ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, and 60

[EPA–HQ–OAR–2017–0355; FRL–9982–89–OAR]

RIN 2060–AT67

Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing three distinct actions, including Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (EGUs). First, EPA is proposing to replace the Clean Power Plan (CPP) with revised emissions guidelines (the Affordable Clean Energy (ACE) rule) that inform the development, submittal, and implementation of state plans to reduce greenhouse gas (GHG) emission from certain EGUs. In the proposed emissions guidelines, consistent with the interpretation described in the proposed repeal of the CPP, the Agency is proposing to determine that heat rate improvement (HRI) measures are the best system of emission reduction (BSER) for existing coal-fired EGUs. Second, EPA is proposing new regulations that provide direction to both EPA and the states on the implementation of emission guidelines. The new proposed implementing regulations would apply to this action and any future emission guideline issued under section 111(d) of the Clean Air Act (CAA). Third, the Agency is proposing revisions to the New Source Review (NSR) program that will help prevent NSR from being a barrier to the implementation of efficiency projects at EGUs.

DATES:

Comments. Comments must be received on or before October 30, 2018. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before October 1, 2018.

Public hearing: EPA is planning to hold at least one public hearing in response to this proposed action. Information about the hearing, including location, date, and time, along with instructions on how to register to speak at the hearing, will be published in a second **Federal Register** document.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2017–0355, at *https://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov.* See **SUPPLEMENTARY INFORMATION** for detail about how EPA treats submitted comments. *Regulations.gov* is our preferred method of receiving comments.[1] However, other submission methods are accepted:

- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2017–0355 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2017–0355.
- *Mail:* To ship or send mail via the United States Postal Service, use the following address: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2017–0355, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* Use the following Docket Center address if you are using express mail, commercial delivery, hand delivery, or courier: EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. Delivery verification signatures will be available only during regular business hours.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Mr. Nicholas Swanson, Sector Policies and Programs Division (Mail Code D205–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–4080; fax number: (919) 541–4991; and email address: *swanson.nicholas@epa.gov.*

SUPPLEMENTARY INFORMATION:

Docket. EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2017–0355. All documents in the docket are listed in *Regulations.gov.* Although listed, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *Regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue 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 EPA Docket Center is (202) 566–1742.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2017–0355. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *https://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *https://www.regulations.gov* or email. This type of information should be submitted by mail as discussed below.

EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

The *https://www.regulations.gov* website allows you to submit your comments anonymously, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA without going through *https://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any

[1] Comments submitted on the proposed repeal will be considered in the promulgation of this rulemaking so there is no need to resubmit comments that have already been timely submitted.

digital storage media you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *https://www.epa.gov/dockets.*

Throughout this proposal, EPA is soliciting comment on numerous aspects of the proposed rule. EPA has indexed each comment solicitation with an alpha-numeric identifier (*e.g.,* ''C–1'', ''C–2'', ''C–3'', . . .). EPA included similar identifiers in the advance notice of proposed rulemaking (ANPRM) and asked commenters to identify the main topic area that corresponded with their comment. In this proposal, we are modifying this approach to include a unique identifier for each individual comment solicitation to provide a consistent framework for effective and efficient provision of comments.

Accordingly, we ask that commenters include the corresponding identifier when providing comments relevant to that comment solicitation. We ask that commenters include the identifier in either a heading, or within the text of each comment (*e.g.,* ''In response to solicitation of comment C–1, . . .'') to make clear which comment solicitation is being addressed. We emphasize that we are not limiting comment to these identified areas and encourage provision of any other comments relevant to this proposal.

Submitting CBI. Do not submit information containing CBI to EPA through *https://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to EPA, mark the outside of the digital storage media as CBI and then identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* above. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2017–0355.

Preamble acronyms and abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, EPA defines the following terms and acronyms here:

ACE Affordable Clean Energy Rule
AEO Annual Energy Outlook
ANPRM Advance Notice of Proposed Rulemaking
BACT Best Available Control Technology
BSER Best System of Emission Reduction
Btu British Thermal Unit
CAA Clean Air Act
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CFR Code of Federal Regulation
CO_2 Carbon Dioxide
CPP Clean Power Plan
EGU Electric Utility Generating Unit
EIA Energy Information Administration
EPA Environmental Protection Agency
FIP Federal Implementation Plan
FR Federal Register
GHG Greenhouse Gas
HRI Heat Rate Improvement
IGCC Integrated Gasification Combined Cycle
kW Kilowatt
kWh Kilowatt-hour
MW Megawatt
MWh Megawatt-hour
NAAQS National Ambient Air Quality Standards
NGCC Natural Gas Combined Cycle
NO_X Nitrogen Oxides
NSPS New Source Performance Standards
NSR New Source Review
OMB Office of Management and Budget
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
RIA Regulatory Impact Analysis
RTC Response to Comments
SIP State Implementation Plan
SO_2 Sulfur Dioxide
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
VFD Variable Frequency Drive

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

I. General Information

A. Executive Summary

EPA is proposing the Affordable Clean Energy (ACE) rule as a replacement to the CPP (promulgated on October 23, 2015, 80 FR 64662), which sets GHG emission guidelines for existing EGUs. This proposal relies in part on the legal analysis presented in the CPP repeal that was proposed on October 16, 2017, 82 FR 48035. In the proposed repeal, EPA asserted that the BSER in the CPP exceeded EPA's authority because it established the BSER using measures that applied to the power sector as whole, rather than measures that apply at and to, and can be carried out at the level of, individual facilities. This proposed action aligns with EPA's statutory authority and obligation because, as EPA has done in the dozens of NSPSs issued to date, the BSER is to be determined by evaluating technologies or systems of emission reduction that are applicable to, at, and on the premises of the facility for an affected source. This proposal will ensure that coal-fired power plants (the most carbon dioxide (CO_2) intensive portion of the electricity generating fleet) address their contribution to climate change by reducing their CO_2 intensity (*i.e.,* the amount of CO_2 they emit per unit of electricity generated).

Accordingly, the proposed ACE rule consists of three discrete sections. First, EPA is proposing to determine the BSER for existing EGUs based on HRI measures that can be applied at an affected source. EPA also proposes a corresponding emission guideline clarifying the roles of EPA and the states under CAA section 111(d). EPA's primary role in implementing CAA section 111(d) is to provide emission guidelines that inform the development, submittal, and implementation of state plans, and to subsequently determine whether submitted state plans are approvable. Per the CAA, once EPA publishes a final emission guideline, states have the primary role of developing standards of performance consistent with application of the BSER. Congress also expressly required that EPA allow states to consider source-specific factors—including, among other factors, the remaining useful life of the affected source—in applying a standard of performance. In this way, the state and federal roles complement each other as EPA has the authority and responsibility to determine a nationally applicable BSER while the states have the authority and responsibility to establish and apply existing source standards of performance, in consideration of source-specific factors.

Second, EPA is proposing new implementing regulations that apply to this action and any future emission guidelines promulgated under CAA section 111(d). The purpose of proposing new implementing regulations is to harmonize our 40 CFR part 60 subpart B regulations with the statute by making it clear that states have broad discretion in establishing and applying emissions standards consistent with the BSER. The discussion for the proposed revisions is found in Section VII below.

Third, EPA is proposing to give the owners/operators of EGUs more latitude to make the efficiency improvements that are consistent with EPA's proposed BSER without triggering onerous and costly NSR permit requirements. This change will allow states, in establishing standards of performance, to consider HRIs that would otherwise not be cost-effective due to the burdens incurred from triggering NSR. The discussion of this issue is included in Section VII.

As with other regulations of this nature, this notice concludes with a summary of the impacts of this proposal and is supported by a Regulatory Impact Analysis (RIA) that can be found in the docket for this action. As reported in the RIA, EPA evaluated three illustrative policy scenarios modeling HRI at coal-fired EGUs. EPA estimates that there are cost savings under two of the three illustrative scenarios, with average annual compliance costs ranging from a cost savings of about \$0.5 billion to a cost of about \$0.3 billion. As noted previously, this action is preceded by a proposed repeal of the CPP.[2] That proposal included a detailed legal analysis demonstrating that ''building blocks'' two and three of the CPP exceeded EPA's authority. That analysis is incorporated into this proposal. Because two of the three ''building blocks'' used to establish the CPP emission guidelines were legally flawed (and because ''building block'' one was not designed in such a manner that it could or was intended to stand on its own without the other building blocks), EPA proposed that the CPP emission guidelines be withdrawn. With the ACE rule, EPA proposes to possibly replace the CPP with a rule that corrects the fundamental legal flaws in the CPP to more appropriately balance federal and state responsibilities under CAA section 111(d), and revise the NSR program as it applies to affected EGUs to better accommodate energy efficiency projects.

This proposed action has been informed by comments submitted in response to the ANPRM, published December 28, 2017, *see* 82 FR 61507. EPA notes that it does not intend to respond to the comments received on the ANPRM. If commenters believe that any of their previously submitted comments are still applicable, they should resubmit those comments to this rulemaking to ensure they are considered.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, EPA will post a copy of this proposed action at *https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-emission-guidelines-greenhouse.* Following publication in the **Federal Register**, EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

II. Background

A. Regulatory and Judicial History of GHG Requirements for EGUs

When passing and amending the CAA, Congress sought to address and remedy the dangers posed by air pollution to human beings and the environment. While the text of the CAA does not reflect an explicit intent on the part of Congress to address the potential effects of elevated atmospheric GHG concentrations, the Supreme Court in *Massachusetts* v. *EPA,* 549 U.S. 497 (2007), concluded that Congress had drafted the CAA broadly enough so that GHGs constituted air pollutants within the meaning of the CAA. EPA subsequently determined that emissions of GHGs from new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. *See* 74 FR 66496 (December 15, 2009). This determination required EPA to regulate GHG emissions from motor vehicles.

In 2009, and again in 2016, the EPA Administrator issued findings under sections 202(a) and 231(a)(2)(A) of the Clean Air Act, respectively, that the current, elevated concentrations of six well-mixed GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare of current and future generations in the

[2] The accompanying RIA focuses on presenting the difference between the CPP and the concepts in ACE, but also includes a scenario with no CPP, providing sufficient information to understand the impact of a full repeal of the CPP, a two-step approach in which the CPP is repealed and then an alternative BSER is put in place or a case in which the Agency revises the BSER promulgated in the CPP.

United States.[3] In 2015, after determining that GHGs from EGUs merited regulation under CAA section 111, EPA promulgated standards of performance for new, modified, and reconstructed EGUs under section 111(b). 80 FR 64510. Consequentially, this led to EPA's obligation to develop a 111(d) rule for existing EGUs, as described in Section III. EPA believes that the BSER in ACE is consistent both with our legal authorities under 111(d) and with what is technically feasible and appropriate for coal-fired power plants. Therefore, EPA believes that the emission reductions required from state plans are the appropriate amount for a 111(d) rule.

While the market in the power sector is driving GHG emissions down, the EPA, by proposing this emission guideline, is reinforcing the market in many respects and also ensuring that available emission reductions that are not market driven are achieved. Many regulations are promulgated to correct market failures, which otherwise lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address ''negative externalities'' whereby the market does not internalize the full opportunity cost of production borne by society as public goods such as air quality are unpriced.

While recognizing that optimal social level of pollution may not be zero, GHG emissions impose costs on society, such as negative health and welfare impacts, that are not reflected in the market price of the goods produced through the polluting process. For this regulatory action the good produced is electricity. If a fossil fuel-fired electricity producer pollutes the atmosphere when it generates electricity, this cost will be borne not by the polluting firm but by society as a whole, thus the producer is imposing a negative externality, or a social cost of emissions. The equilibrium market price of electricity may fail to incorporate the full opportunity cost to society of generating electricity. Consequently, absent a regulation on emissions, the EGUs will not internalize the social cost of emissions and social costs will be higher as a result. This regulation will work towards addressing this market failure by causing affected EGUs to begin to internalize the negative externality associated with CO_2 emissions.

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

Further discussion of GHG impacts, as well as the benefits of this proposal, can be found in the RIA for this action. As detailed in Chapter 3 of the RIA, EPA evaluated three illustrative policy scenarios representing ACE. These scenarios are projected to result in a decrease of annual CO_2 emissions of about 7 million to 30 million short tons relative to a future without a CAA section 111(d) regulation affecting the power sector.

Along with the 111(b) standard, EPA issued, under CAA section 111(d), its ''Clean Power Plan,'' consisting of GHG emission guidelines for *existing* EGUs, which states would use to develop emission standards as mentioned above. 80 FR 64662 (October 23, 2015). In February 2016, the U.S. Supreme Court stayed implementation of the CPP pending judicial review. *West Virginia* v. *EPA,* No. 15A773 (S.Ct. Feb. 9, 2016).

In March 2017, President Trump issued Executive Order 13873, which among other things, directed EPA to reconsider the CPP. After considering the statutory text, context, legislative history and purpose, and in consideration of EPA's historical practice under CAA section 111 as reflected in its other existing CAA section 111 regulations and of certain policy concerns, EPA proposed to repeal the CPP. *See* 82 FR 48035. In a separate but related action, EPA published an ANPRM to solicit comment on what EPA should include in a potential new existing source regulation under CAA section 111(d), including soliciting comment on aspects of the respective roles of the states and EPA in that process, on the BSER in context of the statutory interpretation contained in the proposed repeal of the CPP, on what systems of emission reduction might be available and appropriate, and the potential flexibility that could be afforded under the NSR program to improve the implementation of a potential new existing source regulation for EGUs under CAA section 111(d). 82 FR 61507 (December 28, 2017). EPA received more than 270,000 comments on the ANPRM, which have informed this proposed rulemaking.

In ACE, EPA is proposing to determine that the BSER for GHG emissions from existing coal-fired EGUs is heat rate improvements that can be applied at the source, consistent with the legal interpretation expressed in the proposed repeal. The Agency is also, in this action, clarifying the respective roles of the states and EPA under CAA section 111(d), including by proposing revisions to the regulations, in 40 CFR part 60 subpart B, implementing that section. Section 111(d)(1) of the CAA states that EPA's ''Administrator shall prescribe regulations which shall establish a procedure . . . under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance.'' *See* 42 U.S.C. 7411(d). CAA section 111(d)(1) also requires the Administrator to ''permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' *Id.*

As the plain language of the statute provides, EPA's authorized role under CAA section 111(d)(1) is to develop a procedure for states to establish standards of performance for existing sources. Indeed, the Supreme Court has acknowledged the role and authority of states under section 111(d): This provision allows ''each State to take the first cut at determining how best to achieve EPA emissions standards within its domain.'' *Am. Elec. Power Co.* v. *Connecticut,* 131 S. Ct. 2527, 2539 (2011). The Court addressed the statutory framework as implemented through regulation, under which EPA promulgates emission guidelines and the states establish performance standards: ''For existing sources, EPA issues emissions guidelines; in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction, [42 U.S.C.] § 7411(d)(1).'' *Id.* at 2537–38.

As contemplated by CAA section 111(d)(1), states possess the authority and discretion to establish appropriate standards of performance for existing sources. CAA section 111(a)(1) defines ''standard of performance'' as ''a standard of emissions of air pollutants which reflects'' what is colloquially referred to as the ''Best System of Emission Reduction'' or ''BSER''—*i.e.,* ''the degree of emission limitation achievable through the application of the *best system of emission reduction* which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' 42 U.S.C. 7411(a)(1) (emphasis added).

In order to effectuate the Agency's role under CAA section 111(d)(1), EPA promulgated implementing regulations in 1975 to provide a framework for subsequent EPA rules and state plans under section 111(d). *See* 40 CFR part 60, subpart B (hereafter referred to as the ''implementing regulations''). The implementing regulations reflect EPA's principal task under CAA section 111(d)(1), which is to develop a procedure for states to establish standards of performance for existing sources through state plans. EPA is proposing to promulgate an updated version of the implementing regulations as part of ACE (see Section VII). Per the new proposed implementing regulations, EPA effectuates its role by publishing, an ''emission guideline'' [4] that, among other things, contains EPA's determination of the BSER for the category of existing sources being regulated. *See* 40 CFR 60.22a(b) [''Guideline documents published under this section will provide information for the development of State plans, such as: . . . (4) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated.''] In undertaking this task, EPA ''will specify different emissions guidelines . . . for different sizes, types and classes of . . . facilities when costs of control, physical limitations, geographic location, or similar factors make subcategorization appropriate.'' 40 CFR 60.22(b)(5).

In short, under EPA's new proposed regulations implementing CAA section 111(d), which tracks with the existing implementing regulations in this regard, the guideline document serves to ''provide information for the development of state plans.'' 40 CFR 60.22a(b), with the ''emission guideline,'' reflecting BSER as determined by EPA, being the principal piece of information states rely on to develop their plans that establish standards of performance for existing sources.

Because the CAA cannot necessarily be applied to GHGs in the same manner as other pollutants, *Utility Air Regulatory Group,* 134 S. Ct. 2427, 2455 (2014) (Alito, J., concurring in part and dissenting in part), it is fortuitous that CAA section 111(d) recognizes that states possess considerable flexibility in developing their plans in response to the emissions guideline(s) established by EPA. Specifically, the Act requires that EPA permit states to consider, ''among other factors, the remaining useful life'' of an existing source in applying a standard of performance to such sources. CAA section 111(d)(1).

Additionally, while CAA section 111(d)(1) clearly authorizes states to develop state plans that establish performance standards and provides states with certain discretion in determining appropriate standards, CAA section 111(d)(2) provides EPA specifically a role with respect to such state plans. This provision authorizes EPA to prescribe a plan for a state ''in cases where the State fails to submit a satisfactory plan.'' CAA section 111(d)(2)(A). EPA therefore is charged with determining whether state plans developed and submitted under section 111(d)(1) are ''satisfactory,'' and the proposed new implementing regulations at 40 CFR 60.27a accordingly provides timing and procedural requirements for EPA to make such a determination. Just as guideline documents may provide information for states in developing plans that establish standards of performance, they may also provide information for EPA to consider when reviewing and taking action on a submitted state plan, as the new proposed implementing regulations at 40 CFR 60.27a(c) references the ability of EPA to find a state plan as ''unsatisfactory because the requirements of (the implementing regulations) have not been met.'' [5]

B. Executive Order 13783 and EPA's Review of the CPP

On March 28, 2017, President Trump issued Executive Order 13783, which affirms the ''national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation.'' *See* Executive Order 13783, Section 1(a). The Executive Order directs all executive departments and agencies, including EPA, to ''immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.'' *Id.* Section 1(c). The Executive Order further affirms that it is ''the policy of the United States that necessary and appropriate environmental regulations comply with the law.'' *Id.* Section 1(e). Moreover, the Executive Order specifically directs EPA to review and initiate reconsideration proceedings to ''suspend, revise, or rescind'' the CPP, ''as appropriate and consistent with law.'' *Id.* Section 4(a)–(c).

In a document signed the same day as Executive Order 13783, and published in the **Federal Register** at 82 FR 16329 (April 4, 2017), EPA announced that, consistent with the Executive Order, it was initiating its review of the CPP and providing notice of forthcoming proposed rulemakings consistent with the Executive Order.[6] In the course of EPA's review of the CPP, the Agency also reevaluated its interpretation of CAA section 111, and, on that basis, the Agency proposed to repeal the CPP. *See* 82 FR 48035.

This action proposes a BSER for GHGs from existing EGUs in line with the interpretation presented in the proposed CPP repeal. *See* 82 FR 48038–42. Comments submitted on the proposed repeal will be considered in the promulgation of this rulemaking so there is no need to resubmit comments that have already been timely submitted.

C. Industry Trends

Carbon dioxide emissions in the power sector have steadily declined in recent years due to a variety of power industry trends, which are expected to continue. The reduction in power sector CO_2 emissions is the result of industry trends away from coal-fired generation and toward low- and zero-emitting generation sources. These trends have been driven by market factors, reduced electricity demand, and policy and regulatory efforts. These trends have resulted in a notable change to the country's overall generation mix, as more natural gas and renewable energy is used to generate electricity relative to coal-fired electricity. The price of natural gas is expected to remain low for the foreseeable future as improvements in drilling technologies and techniques continue to reduce the cost of extraction. In addition, the existing fleet of coal-fired EGUs is aging and there are very few new coal-fired generation

[4] *See* Section VII.A. for proposed changes to the definition of ''emission guideline'' as part of EPA's proposed new implementing regulations.

[5] *See also* 40 FR 53343 (''If there is to be substantive review, there must be criteria for the review, and EPA believes it is desirable (if not legally required) that the criteria be made known in advance to the States, to industry, and to the general public. The emission guidelines, each of which will be subjected to public comment before final adoption, will serve this function.'').

[6] EPA also withdrew the proposed federal plan and model trading rules, proposed amendments to certain regulations under 40 CFR part 60, subpart B, implementing CAA section 111(d), and proposed rule regarding the Clean Energy Incentive Plan. 82 FR 16144 (April 3, 2017).

projects under development. With a continued (but reduced) tax credit and declining capital costs, solar capacity will continue to grow through 2050 while tax credits that phase out for plants entering service through 2024 provide incentives for new wind capacity in the near-term. Some power plant generators have announced that they expect to continue to change their generation mix away from coal-fired generation toward natural-gas fired generation, renewables and more deployment of energy efficiency measures. All of these trends, in total, are expected to result in declining power sector CO_2 emissions.

In the near-term, according to the U.S. Energy Information Administration's (EIA) 2018 Annual Energy Outlook, ''the cumulative effect of increased coal plant retirements, lower natural gas prices and lower electricity demand in the AEO2018 Reference case is a reduction in the projected [CO_2] emissions from electric generators, even without the [CPP]. In 2020, electric power sector CO_2 emissions are projected to be 1.72 billion metric tons, which is 120 million metric tons (7 percent) lower than the projected level of CO_2 emissions in the AEO2017 Reference case without the CPP.'' [7] In other words, these declining emission trends have continued to develop even in the absence of implementation of the CPP.

In consideration of these ongoing and projected power sector trends and a resulting decline in power sector CO_2 emissions, EPA is soliciting comment on whether and how to consider such trends in developing CO_2 emission guidelines for the power sector. A comparison of EIA projections to EPA analysis for the original proposed CPP demonstrates that the rapid changes in the power sector are leading to CO_2 emission reductions at a faster rate than projected even a few years ago when the CPP was promulgated (Comment C–1). EPA also notes that CO_2 emissions are projected to increase over time in some EIA AEO side cases, and, given the uncertainties associated with long-term emission projections, solicits comments on the applicability of those alternative results.

Because of the rapid pace of these power sector changes, it is difficult for sector analysts to fully account for these changing trends in near-term and long-term sector-wide projections. This means that regulatory decisions made today could be based on information that may very well be outdated within the next several years. If that is the case, work put in by federal and state regulatory agencies—as well as by the affected sources themselves—to address section 111(d) requirements could quickly be overtaken by external market forces which could make those efforts redundant or, even worse, put them in conflict with industry trends that are already reducing CO_2 emissions.

[7] U.S. EIA, *Annual Energy Outlook 2018 with projections to 2050* (February 6, 2018), at 102, available at *https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.*

III. Legal Authority

A. Authority To Revisit Existing Regulations

EPA's ability to revisit existing regulations is well-grounded in the law. Specifically, EPA has inherent authority to reconsider, repeal or revise past decisions to the extent permitted by law so long as the Agency provides a reasoned explanation. The CAA complements EPA's inherent authority to reconsider prior rulemakings by providing the Agency with broad authority to prescribe regulations as necessary. 42 U.S.C. 7601(a); *see also* Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills, 81 FR 59276, 59277–78 (August 29, 2016). The authority to reconsider prior decisions exists in part because EPA's interpretations of statutes it administers ''[are not] instantly carved in stone,'' but must be evaluated ''on a continuing basis.'' *Chevron U.S.A. Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 863–64 (1984). This is true when, as is the case here, review is undertaken ''in response to . . . a change in administrations.'' *National Cable & Telecommunications Ass'n* v. *Brand X Internet Services,* 545 U.S. 967, 981 (2005). Indeed, ''[a]gencies obviously have broad discretion to reconsider a regulation at any time.'' *Clean Air Council* v. *Pruitt,* 862 F.3d 1, 8–9 (D.C. Cir. 2017).

B. Authority To Regulate EGUs

In the CPP, EPA stated that EPA's then-concurrent promulgation of standards of performance regulating CO_2 emissions from new, modified, and reconstructed EGUs triggered the need to regulate existing sources under CAA section 111(d). 80 FR 64715. In ACE, we are not re-opening any issues related to this conclusion, but for the convenience of stakeholders and the public, we will summarize our explanation here.

We explained in the CPP that CAA section 111(d)(1) requires EPA to promulgate regulations under which states must submit state plans regulating ''any existing source'' of certain pollutants ''to which a standard of performance would apply if such existing source were a new source.'' *Id.* Under CAA section 111(a)(2) and 40 CFR 60.15(a), a ''new source'' is defined as any stationary source, the construction, modification, or reconstruction of which is commenced after the publication of proposed regulations prescribing a standard of performance under CAA section 111(b) applicable to such source. We noted that, at that time, we were concurrently finalizing a rulemaking under CAA section 111(b) for CO_2 emissions from affected EGUs, which provided the requisite predicate for applicability of CAA section 111(d). *Id.*

EPA explained in the 111(b) rule (80 FR 64529) that ''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.'' EPA further explained that, because EGUs had previously been listed, it was unnecessary to make an additional finding. The Agency also noted that, under section 111(b)(1)(A), findings are category specific and not pollutant specific, so a new finding is not needed with regard to a new pollutant. The Agency further asserted that, even if it were required to make a finding, given the large amount of CO_2 emitted from this source category (the largest single stationary source category of emissions of CO_2 by far) that EGUs would easily meet that standard. The Agency further noted that, given the large amount of emissions from the source category, it was not necessary in that rule ''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.'' 80 FR 64531.

That CAA section 111(b) rulemaking remains on the books, although EPA is currently considering revising it. Accordingly, it continues to provide the requisite predicate for applicability of CAA section 111(d). Any comments on the issues discussed in this subsection would be more appropriately addressed to the docket on EPA's intended forthcoming proposal with regard to the new source rule.

C. Legal Authority for Determination of the BSER

As discussed above, EPA's authorized role under CAA section 111(d) is to establish a procedure under which states submit plans establishing standards of performance for existing sources, reflecting the application of the best system of emission reduction that EPA has determined is adequately demonstrated for the source category. In the CPP, EPA determined that the BSER for CO_2 emissions from existing fossil fuel-fired power plants was the combination of emission rate improvements and limitations on overall emissions by affected power plants that can be accomplished through a combination of three sets of measures, which the EPA called ''building blocks'':

1. Improving heat rate at affected coal-fired steam generating units;
2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for decreased generation from higher-emitting affected steam generating units; and
3. Substituting increased generation from new zero-emitting renewable energy generating capacity for decreased generation from affected fossil fuel-fired generating units.

While building block 1 constituted measures that could be applied directly to a source—that is, integrated into its design or operation—building blocks 2 and 3 employed generation-shifting measures that departed from this traditional, source-specific approach to regulation.

As explained in the proposed repeal, after reconsidering the statutory text, context and legislative history, and in consideration of EPA's historical practice under CAA section 111 as reflected in its other existing section 111 regulations, the Agency proposes to return to a reading of section 111(a)(1) (and its constituent term, ''best system of emission reduction'') as being limited to emission reduction measures that can be applied to or at an individual stationary source. That is, such measures must be based on a physical or operational change to a building, structure, facility or installation at that source rather than measures the source's owner or operator can implement at another location. For a more detailed discussion of EPA's proposed interpretation, see 82 FR 48039–42.

In proposing ACE, EPA offers additional legal rationale to support its determination that heat-rate improvements constitute the BSER. EPA solicits comment on these additional legal interpretations (Comment C–2).

First, as explained in the CPP preamble, reduced utilization ''does not fit within our historical and current interpretation of the BSER.'' *See* 80 FR 64780; *see also id.* at 64762 (''EPA has generally taken the approach of basing regulatory requirements on controls and measures designed to reduce air pollutants from the production process without limiting the aggregate amount of production.'') Whereas some emission reduction measures (such as a scrubber) may have an incidental impact on a source's production levels, reduced utilization is directly correlated with a source's output. Moreover, predicating a CAA section 111 standard on a source's non-performance would inappropriately inject the Agency into an owner/operator's production decisions. In returning to our historical understanding of and practice under section 111, we reiterate that reduced utilization is not a valid system of emission reduction for purposes of establishing a standard of performance. EPA believes our proposed interpretation that the BSER be limited to measures that can be applied at or to a source does not command a different result.

Second, as explained in the proposed repeal notice, interpretative constraints that may apply to interpreting CAA section 111(a)(1) (*i.e.,* determining what types of measures that may be considered as the BSER) for purposes of setting a new source performance standard under section 111(b) reasonably may be applied to interpreting the BSER for purposes of setting existing source standards under section 111(d) as well (and, given that ''standard of performance'' is given a unitary definition for purposes of the entire statutory section, applying the same interpretative constraints may in fact be required). For example, we proposed that ''the BSER should be interpreted as a source-specific measure, in light of the fact that [Best Available Control Technology, or BACT] standards, for which the BSER is expressly linked by statutory text, are unambiguously intended to be source-specific.'' [8] *See* 82 FR 48042.

Under the CAA and applicable regulations, certain preconstruction permits must contain emissions limitations based on application of BACT for certain regulated pollutants. EPA recommends that permitting authorities follow a five-step ''top-down'' BACT analysis, which calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness.[9] The options are then assessed in consideration of technical, energy, environmental and economic factors until an option is selected as BACT.

In reviewing our BACT guidance, we have identified additional interpretive constraints that may be applied to CAA section 111. Specifically, in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases,* we explained that a BACT analysis ''need not necessarily include inherently lower polluting processes *that would fundamentally redefine the nature of the source* proposed by the permit applicant.'' *Id.* at 26 (emphasis added). Furthermore, we explained that ''BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.'' *Id.* Indeed, ''EPA has recognized that the initial list of control options for a BACT analysis does not need to include 'clean fuel' options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel type (*i.e.,* coal, natural gas or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process.'' *Id.* at 27. EPA has even noted that ''applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity).'' [10] Although in the CPP we believed that EPA's ''redefining the source'' policy was not relevant for purposes of section 111(d), *see* CPP RTC Chapter 1A, 170–72, we now believe that such a policy is relevant in light of the relationship between BACT and BSER. In the response to comments accompanying the CPP, EPA rejected the relevance to BSER under section 111 of the Agency's general policy against ''redefining the source'' in the context of PSD/BACT. EPA now believes that it was incorrect in its response, and that it is worth examining this point in some detail because it encapsulates several key aspects of the CPP's interpretation

[8] *See* 40 CFR 52.21(b)(12); *see also* 42 U.S.C. 7479(3).

[9] The five steps are: (1) Identify all available control technologies; (2) eliminate technically infeasible options; (3) rank remaining control technologies; (4) evaluate most effective controls and document results; and (5) select the BACT.

[10] New Source Review Workshop Manual, at B.13 (Draft) (October 1990), available at *https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.*

of section 111 in general and section 111(d) in particular that EPA now proposes to conclude in ACE are not appropriate interpretations of the statute.

In its response to comments, EPA largely based its rejection of the relevance of PSD to BSER on what it saw as the salient distinctions between the sources subject to, and mode of operation of, the two statutory programs. In this regard, EPA spoke of the ''distinct context of the PSD program, which involves the case-by-case review of the construction of an *individual stationary source.* . . . BACT is not applicable to unmodified existing sources *nor is it applied on a source category basis.* The CAA's PSD program is *administered primarily by state and local permitting authorities* as [an] individualized preconstruction requirement under CAA section 165. Under section 111(d), the Administrator identifies a list of adequately demonstrated control options in use by the industry, selects the best of those control options after considering cost and other factors, *then selects an achievable limit for the category* through the application of the BSER across the industry. . . .'' (Emphases added.)

Here, EPA's response disregarded the fact that under CAA section 111(d), the statute explicitly tasks states—not the Administrator—with ''establishing standards of performance'' for existing sources, and that the statute expressly requires EPA to allow the state to take into account source-specific factors when doing so. A ''standard of performance'' is defined at 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'' BSER. (Emphasis added.) Therefore, it is the state, not EPA, that is tasked in the first instance with ''select[ing] an achievable limit'' for existing sources—and section 111(d)'s emphasis on source-specific factors at the very least renders questionable EPA's unqualified assertion that BSER for existing sources ''is applied on a source category basis.'' In the instant proposal, EPA proposes to give full meaning to these textual and structural features of the existing-source program under section 111(d) that render it in important respects distinct from the new-source program under section 111(b) and similar to the source-by-source PSD program: Section 111(d), unlike section 111(b), is implemented in the first instance by the states, and it is expressly linked to source-specific factors. These similarities counsel against EPA's prior rejection of the relevance of the general policy under PSD against ''redefining the source.''

Furthermore, speaking of the generation-shifting measures that constituted the second and third ''building blocks'' of the CPP, EPA asserted that ''those measures are part of the business purposes and objectives *within the power sector.* Accordingly, the BSER, which incorporates building blocks 2 and 3, cannot be said to force a fundamental redefinition *of the business of generating electric power.*'' (Emphases added.) The emphasized phrases reveal the influence of EPA's statutory interpretation underlying the CPP: That EPA can regulate under CAA section 111 at the level of an entire industrial sector, and that the business that it is regulating is ''generating electric power'' writ large—rather than a recognition in line with the statute's text and structure, and EPA's practice prior to the CPP, of regulating the performance of individual sources through measures carried out at and by the individual source.

EPA rested on its discretionary prerogative: ''EPA's policies under CAA section 165 regarding the construction of individual sources are not controlling for purposes of establishing *category-wide standards for existing sources* under CAA section 111(d). Even if the PSD 'redefining the source' policies were applicable in this context, *it would be within the Administrator's discretion to consider requiring a fundamental redesign* of a newly constructed or modified source[ ]. EPA's case-by-case application of CAA section 165 in the PSD program does not limit the Administrator's *discretion in establishing an emission guideline for an entire category of existing sources* under CAA section 111(d).'' (Emphases added.) EPA has explained, both in the proposed repeal and the instant proposal, why it is proposing to conclude that the statute does not, in fact, delegate discretion to the Administrator to ''establish . . . for an entire category of existing sources'' standards that can only be accomplished by ''a fundamental redesign'' of that category, of the generation mix, and of the division of jurisdiction over electricity generation within the federal government and between the federal government and the states. But to the extent that the Agency, due to the fact that Congress did not expressly forbid such an approach, does possess that discretion, today it proposes not to exercise it.

Third, notwithstanding the relationship between BACT and BSER, we believe that measures ''redefining the source'' should be excluded from consideration for purposes of CAA section 111(d). *See, e.g., Sierra Club* v. *EPA,* 499 F.3d 653, 655 (7th Cir. 2007) (''Refining the statutory definition . . . to exclude redesign is the kind of judgment by an administrative agency to which a reviewing court should defer.''). Indeed, the policy against redefining a source is even more sensible when applied to existing sources. Under section 111(d), regulated sources are well past the proposal stage and redefining such sources would likely require, at a minimum, significant modification and could even require decommissioning, redesign and new construction. Accordingly, we propose to recognize that the BSER analysis need not include options that would ''fundamentally redefine the source,'' irrespective of the application of that policy under PSD. For purposes of ACE, therefore, we did not consider natural gas repowering (*i.e.,* converting from a coal-fired boiler to a gas-fired turbine) or refueling (*i.e.,* converting from a coal-fired boiler to a natural gas-fired boiler) as a system of emission reduction for coal-fired steam generating units.

Fourth, the legislative history underlying CAA section 111 confirms that Congress intended this provision to be source oriented. The Senate Committee Report on Senate Bill 4358 explained that ''[t]he provisions for new source performance standards [*i.e.,* S. 4538, section 113] [11] are designed to insure [sic] that new stationary sources *are designed, built, equipped, operated, and maintained* so as to reduce emissions to a minimum.'' S. Committee Rep. to accompany S. 4358 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415–16 (emphasis added). Similarly, ''[e]mission standards developed under [S. 4538, section 114] would be applied to existing stationary sources. However, the Committee recognizes that *certain old facilities may use equipment and processes which are not suited to the application of control technology.*'' *Id.* at 1970 CAA Legis. Hist. at 419 (emphasis added) (noting further that in such cases, the application of standards could be waived).

The proposed interpretive scope of the BSER is reasonable because it focuses the BSER on the performance of the emitting unit itself, rather than the performance of the emitting unit and the transmission system to which it belongs. EPA's area of expertise is control of emissions at the source. EPA is not the expert agency with regard to electricity management. FERC is the expert at the

[11] Section 113 of Senate Bill 4538 would become CAA section 111; section 114 of the Senate Bill would become CAA section 111(d).

federal level and public utility commissions are the experts at the state and local level. Numerous factors might be considered in determining which power plants dispatch on a given system or operate at any given time (*e.g.,* cost of service, voltage support, electricity demand, availability of renewable resources, *etc.*). Moreover, numerous factors are relevant in determining how much new/replacement generation capacity is needed and what types of generating resources best satisfy that need. EPA has no express legal authority and no particular expertise in any of these areas. This is particularly relevant because, as noted below, there are already significant changes taking place within the power sector that are resulting in shifts away from coal-fired generation to new technologies such as renewables. This shift is creating tremendous strain on the power infrastructure even without the added pressures of an EPA mandate to further shift away from additional coal-fired generation. Many experts have expressed concern that these pressures could create reliability problems. As DOE noted in a 2017 report on electricity markets and reliability, ''Ultimately, the continued closure of traditional baseload power plants calls for a comprehensive strategy for long-term reliability and resilience. States and regions are accepting increased risks that could affect the future reliability and resilience of electricity delivery for consumers in their regions. Hydropower, nuclear, coal, and natural gas power plants provide essential reliability services and fuel assurance critical to system resilience. A continual comprehensive regional and national review is needed to determine how a portfolio of domestic energy resources can be developed to ensure grid reliability and resilience.'' [12] Because EPA believes it is not appropriate to further challenge the nation's electricity system while these important technical and policy issues are being addressed. EPA believes that it is reasonable to focus on a ''BSER'' limited to consideration of emission control measures that can be applied at or to coal-fired units, ensuring that regardless of how much coal-fired generation remains, that generation is operated to minimize CO_2 emissions.

Also, the proposed interpretive scope of the BSER is reasonable considering the several important economic, policy and technology shifts occurring in the power sector. The first change is being driven by low natural gas prices that make lower carbon-emitting NGCC units more competitive as compared to higher carbon-emitting coal plants. Another important change is driven by both technology changes and by state and national energy policy decisions that have made renewable energy (*e.g.,* solar and wind energy) more competitive compared to coal and natural gas. The third notable change is driven by aging coal plants, which considering the economic competitive pressures driven by natural gas and renewable generation, are leading companies to conclude that a significant number of coal plants are reaching the end of their useful economic life or are no longer economic to operate.

These trends have driven down GHG emissions from power plants, which were also key components to the BSER as defined in the CPP. In fact, the analysis that EPA has done for ACE (see RIA), as well as analysis by many others (including EIA), show that these trends have already well outpaced the projections that went into the CPP for many states. For this reason, establishing a BSER on assumptions for generation by various sources that accounts for the continuation of these trends into the future would create significant work for both states and sources that may or may not result in emission reductions from ACE if the actual trends once again prove to be stronger than projected.

While some might suggest that this argues that the BSER in ACE should still follow the same approach as the CPP, adjusting this proposal to be even more stringent ignores the fact that the uncertainties that have resulted in faster than projected emission reductions are also uncertain in the opposite direction. From 2005 to 2008, gas prices experienced several unexpected peaks that were not anticipated. If this were to happen in the future, it would make any rule based on CPP-type assumptions significantly more expensive. Similarly, while the recent past has shown continued advances in renewable cost and performance, it is not certain that those trends will be sustained. It should be noted that federal tax subsidies that have been key to this trend are set to expire over the next several years which may play a role in the future.

Because of these significant uncertainties that can have large impacts on electric reliability and the cost of electricity to consumers, EPA believes that this further supports the unreasonableness of basing the BSER on generation-shifting measures. Regardless of the path that the power sector takes, coal-fired power plants are likely to be an important part of the generation mix for the foreseeable future, therefore EPA believes it is reasonable to ensure that the remaining coal-fired generation (which is also the most CO_2 intensive portion of the power sector) focuses on reducing that CO_2 emission intensity to the extent technically feasible considering cost.

EPA believes that a BSER focused on making these plants as efficient as possible is the best way to ensure GHG emission reductions regardless of other factors such as technology changes for other types of generation, changes in fuel price, changes in electricity demand or changes in energy policy that neither environmental regulators nor power companies have the power to control.

IV. Affected Sources

EPA is proposing that an affected EGU subject to regulation upon finalization of ACE is any fossil fuel-fired electric utility steam generating unit (*i.e.,* utility boilers) that is not an integrated gasification combined cycle (IGCC) unit (*i.e.,* utility boilers, but not IGCC units) that was in operation or had commenced construction as of August 31, 2018,[13] and that meets the following criteria.[14] To be an affected EGU, a fossil fuel-fired electric utility steam generating unit must serve a generator capable of selling greater than 25 MW to a utility power distribution system and have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel).

EPA is proposing different applicability criteria than in the CPP to reflect EPA's determination of the BSER for only fossil fuel-fired electric utility steam generating units. In ACE, EPA does not identify a BSER for stationary combustion turbines and IGCC units and, thus, such units are not affected EGUs for purposes of this action (see discussion below in Section V.B). It should be noted, in the CPP's identification of the BSER, no HRIs were identified as the BSER for stationary combustion turbines and IGCC units. Nevertheless, EPA solicits comment on systems of emission reduction that might be the BSER for these types of

[12] U.S. DOE, *Staff Report to the Secretary on Electricity Markets and Reliability* (August 2017) at 14, available at *https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.*

[13] Under section 111(a) of the CAA, determination of affected sources is based on the date that EPA proposes action on such sources. January 8, 2014 is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the **Federal Register** (79 FR 1430).

[14] To be clear, this definition of an affected EGU does not, at this time, include stationary combustion turbines for reasons discussed later in this document.

EGUs (Comment C–3). EPA notes that, under the CPP, certain EGUs were not considered to be affected EGUs, and therefore were exempt from inclusion in a state plan. Similarly, EPA is proposing for ACE, the following EGUs would be excluded from a state's plan: (1) Those units subject to 40 CFR 60 subpart TTTT as a result of commencing modification or reconstruction; (2) steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis; (3) non-fossil units (*i.e.,* units capable of combusting at least 50 percent non-fossil fuel) that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) units that serve a generator along with other steam generating unit(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit) is 25 MW or less; (5) municipal waste combustor unit subject to 40 CFR part 60, subpart Eb; or (6) commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC. EPA solicits comment on whether there should be a different definition of affected EGUs for ACE (Comment C–4).

V. Determination of the BSER

CAA section 111(d)(1) directs EPA to promulgate regulations establishing a CAA section 110-like procedure under which states submit state plans that establish ''standards of performance'' for emissions of certain air pollutants from sources which, if they were new sources, would be subject to new source standards under section 111(b), and that provide for the implementation and enforcement of those standards of performance. The term ''standard of performance'' is defined in 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 [BSER] which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.''

Thus, EPA is authorized to determine the BSER for affected sources. *See also* 40 CFR 60.22. In making this determination, EPA identifies all ''adequately demonstrated'' [15] ''system[s] of emission reduction'' for a particular source category and then evaluates those systems to determine which is the ''best'' [16] while ''taking into account'' the factors of ''cost . . . nonair quality health and environmental impact and energy requirements.'' Because CAA section 111 does not set forth the weight that should be assigned to each of these factors, courts have granted the Agency a great degree of discretion in balancing them. *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (internal citations omitted).

CAA section 111(d)(1) assigns responsibility to the states for establishing standards of performance for affected existing sources—in contrast to section 111(b), which directs EPA to set standards of performance for affected new sources.

A. Identification of the BSER

In ACE, EPA identified several systems of emission reduction for existing fossil-fuel fired steam generating EGUs (*i.e.,* heat rate improvements; carbon capture and storage; and fuel co-firing, including with natural gas and biomass) and evaluated each of these systems to determine which is the ''best'' while taking into account cost, nonair quality health and environmental impact and energy requirements.

EPA proposes to identify ''heat rate improvements'' (which may also be referred to as ''efficiency improvements'') as the BSER for existing fossil-fuel fired steam generating EGUs. The basis for this determination is discussed below. A discussion of other potential CO_2 reduction measures that EPA has determined are not BSER (but which states may allow sources to use for compliance purposes) is also provided below.

The U.S. fleet of existing coal-fired EGUs is a diverse group of units with unique individual characteristics, spread across the country. Coal-fired power plants are customized facilities that were designed and built to meet local and regional electricity needs over the past 100 years, with no two plants being identical. Geography and elevation, unit size, coal type, pollution controls, cooling system, firing method and utilization rate are just a few of the parameters that can impact the overall efficiency and performance of individual units. As a result, heat rates of existing coal-fired EGUs in the U.S. vary substantially. The variation in heat rates among EGUs with similar design characteristics, as well as year-to-year variation in heat rate at individual EGUs, indicate that there is potential for HRIs that can improve CO_2 emission performance for the existing coal-fired EGU fleet, but that this potential may vary considerably at the unit level.

EPA does not currently have sufficient information on adequately demonstrated systems of emission reduction—including HRI opportunities—for existing natural gas-fired stationary combustion turbines. As such, the Agency is currently unable to determine the BSER for such units. In this action, EPA solicits information on adequately demonstrated systems of GHG emission reduction for such units—especially on the efficiency, applicability, and cost of such systems (Comment C–5). This is discussed in greater detail below.

B. HRIs for Steam-Generating EGUs

As mentioned above, EPA proposes in ACE to identify ''heat rate improvements'' as the BSER for existing steam generating fossil fuel-fired EGUs. Heat rate is a measure of efficiency that is commonly used in the power sector. The heat rate is the amount of energy input, measured in British thermal units (Btu), required to generate one kilowatt-hour (kWh) of electricity. The lower an EGU's heat rate, the more efficiently it operates. As a result, an EGU with a lower heat rate will consume less fuel per kWh generated and emit lower amounts of CO_2 and other air pollutants per kWh generated as compared to a less efficient unit. An EGU's heat rate can be affected by a variety of design characteristics, site-specific factors, and operating conditions, including:

- Thermodynamic cycle of the boiler;

[15] Case law under CAA section 111(b) explains that ''[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973). While some of these cases suggest that ''[t]he Administrator may make a projection based on existing technology,'' *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973), the D.C. Circuit has also noted that ''there is inherent tension'' between considering a particular control technique as both ''an emerging technology and an adequately demonstrated technology,'' *Sierra Club* v. *Costle,* 657 F.2d 298, 341 n.157 (D.C. Cir. 1981). *See also NRDC* v. *Thomas,* 805 F.2d 410, n. 30 (D.C. Cir. 1986) (suggesting that ''a standard cannot both require adequately demonstrated technology and also be technology-forcing.''). Nevertheless, EPA appears to ''have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.'' *Sierra Club,* 657 F.2d at 364.

[16] The D.C. Circuit recognizes that EPA's evaluation of the ''best'' system must also include ''the amount of air pollution as a relevant factor to be weighed . . . .'' *Id.* at 326.

- Boiler and steam turbine size and design;
- Cooling system type;
- Auxiliary equipment, including pollution controls;
- Operations and maintenance practices;
- Fuel quality; and
- Ambient conditions.

In the CPP, EPA quantified emission reductions achievable through heat rate improvements on a regional basis (*i.e.,* building block 1). The Agency concluded that EGUs can achieve on average a 4.3 percent improvement in the Eastern Interconnection, a 2.1 percent improvement in the Western Interconnection and a 2.3 percent improvement in the Texas Interconnection. *See* 80 FR 64789. The Agency then applied all three of the building blocks to 2012 baseline data and quantified, in the form of CO_2 emission rates, the reductions achievable in each interconnection in 2030 and selected the least stringent as a national performance rate. *Id.* at 64811–819. EPA noted that building block 1 measures could not by themselves constitute the BSER because of a potential ''rebound effect.'' [17] *Id.* at 64787.

EPA believes that building block 1, as constructed in CPP, does not represent an appropriate BSER, and ACE better reflects important changes in the formulation and application of the BSER in accordance with the CAA. For example, the percent improvement applied as the BSER under CPP was determined at the interconnect-level, and did not take into account remaining useful life or other source-specific factors, which are addressed in this proposed rule.[18] The current fleet of existing fossil fuel-fired EGUs is quite diverse in terms of size, age, fuel type, operation (*e.g.,* baseload, cycling), boiler type, *etc.* Many coal-fired EGUs now operate under load-following and cycling conditions as opposed to the steady baseload operating conditions that were more common a decade ago.

There are available technologies and equipment upgrades, as well as best operating and maintenance practices, that EGU owners or operators may utilize to improve an EGU's heat rate. In the ANPRM, EPA solicited information on a number of technology and equipment upgrades and good practices (specifically including, but not limited to, those that were listed in Tables 1 and 2 of the ANPRM, *see* 82 FR 61514) that have the potential to reduce an EGU's heat rate.

Specifically, the Agency solicited information on: (1) Potential HRIs from technologies and best operating and maintenance practices; (2) costs of deploying the technologies and the best operating and maintenance practices, including applicable planning, capital and operating and maintenance costs; (3) owner and operator experiences deploying the technologies and employing best operating and maintenance practices; (4) barriers to or from deploying the technologies and operating and maintenance practices; and (5) any other technologies or operating and maintenance practices that may exist for improving heat rate, but were not listed in the ANPRM.

EPA received useful information in the comments submitted in response to the ANPRM. Many commenters contended that any evaluation of the HRI potential of the coal-fired EGU fleet must be done on a unit-by-unit basis since the opportunities for HRI are source-specific and dependent upon the individual unit's design, configuration, and operating and maintenance history. Many commenters emphasized the significant influence that the operating mode (*i.e.,* whether the unit operates at consistent baseload conditions or in cycling or load-following mode or as a low capacity factor unit that is subject to frequent startups and shutdowns) has on an individual EGU's heat rate and HRI potential. Many commenters also claimed that owners and operators of fossil fuel-fired EGUs already routinely conduct HRI efforts and, as a result, there are relatively few economic improvement opportunities available.

1. Potential HRI Measures—Technologies and Equipment Upgrades

As mentioned above, numerous technologies and equipment upgrades, as well as best operating and maintenance practices (which are discussed in the next section), have been identified as potential measures to improve an EGU's heat rate. In the ANPRM, EPA solicited information on a large number of technology and equipment upgrades and best operating and maintenance practices that have the potential to reduce an EGU's heat rate. *See* Tables 1 and 2 of the ANPRM, 82 FR 61514.

In this action, EPA is proposing to determine that heat rate improvement is the BSER for affected existing coal-fired EGUs and is proposing a list of ''candidate technologies'' of HRI measures for states to use in establishing standards of performance under CAA section 111(d)(1). States can use the information that EPA provides on the ''degree of emission limitation achievable through application of the [BSER]'' to establish standards of performance for affected EGUs covered by a state's plan.[19] While a large number of HRI measures have been identified in a variety of studies conducted by government agencies and outside groups (*see* Table 3 in ANPRM, 82 FR 61515), some of those identified technologies have limited applicability and many provide only negligible HRI. EPA believes that it would be overly burdensome to require States to evaluate the degree of emission limitation achievable from the application of every single identified HRI measure—including those with negligible benefits—at each source (or subcategory of sources) within their borders. Therefore, EPA has identified a list of the ''most impactful'' HRI measures that we are proposing to serve as technologies, equipment upgrades and best operating and maintenance practices that form the list of ''candidate technologies'' constituting the BSER. The candidate technologies of the BSER is listed in Table 1 below. Best operating and maintenance practices are discussed in the next section. States are expected to evaluate each of the BSER HRI measures in the candidate technologies in establishing a standard of performance for any particular source. The States, in applying a standard of performance, may take into consideration, among other factors, the remaining useful life of the existing source to which the standard would apply. EPA solicits comments on whether other unlisted HRI measures should also be included as part of the BSER and added to the candidate technologies (Comment C–6). EPA also solicits comment on each of the candidate technologies described further below, including whether any additional technologies should be added to the list, and whether there is additional information that EPA should be aware of and consider in determining the BSER and establishing the candidate technologies for HRI measures (Comment C–7).

The technologies and operating and maintenance practices listed and

[17] As discussed below, EPA modeled a range of potential HRIs for ACE and the Agency's analysis indicates that system-wide emission decreases from heat rate improvements will likely outweigh any potential system-wide emission increases. Accordingly, EPA proposes to conclude that the ''rebound effect'' does not preclude a determination that HRIs constitute the BSER.

[18] The Agency solicits comments, nonetheless, on whether and how to retain building block 1 in lieu of the proposed approach.

[19] The states, in applying the unit-specific standard, may also take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies. *See* CAA section 111(d)(1).

described below may not be available or appropriate for all types of EGUs; and some owners or operators will have already deployed some of the technologies and employed some of the best operating and maintenance practices.

TABLE 1—SUMMARY OF MOST IMPACTFUL HRI MEASURES AND RANGE OF THEIR HRI POTENTIAL (%) BY EGU SIZE

HRI measure	<200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved O&M Practices	Can range from 0 to >2.0% depending on the unit's historical O&M practices.					

a. Neural Network/Intelligent Sootblower

Neural networks. Computer models, known as neural networks, can be used to simulate the performance of the power plant at various operating loads. Typically, the neural network system ties into the plant's distributed control system for data input (process monitoring) and process control. The system uses plant specific modeling and control modules to optimize the unit's operation and minimize the emissions. This model predictive control can be particularly effective at improving the plants performance and minimizing emissions during periods of rapid load changes. The neural network can be used to optimize combustion conditions, steam temperatures, and air pollution control equipment.

Intelligent Sootblowers. During operations at a coal-fired power plant, particulate matter (ash or soot) builds up on heat transfer surfaces. This build-up degrades the performance of the heat transfer equipment and negatively affects the efficiency of the plant. Power plant operators use steam injection ''sootblowers'' to clean the heat transfer surfaces by removing the ash build-up. This is often done on a routine basis or as needed based on monitored operating characteristics. Intelligent sootblowers (ISB) are automated systems that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup.

The cost to implement an ISB system is relatively inexpensive if the necessary hardware is already installed. The ISB software/control system is often incorporated into the neural network software package mentioned above. As such, the HRIs obtained via installation of neural network and ISB systems are not necessarily cumulative.

The efficiency improvements from installation of intelligent sootblowers are often greatest for EGUs firing subbituminous coal and lignite due to more significant and rapid fouling at those units as compared to EGUs firing bituminous coal.

b. Boiler Feed Pumps

A boiler feed pump (or boiler feedwater pump) is a device used to pump feedwater into a boiler. The water may be either freshly supplied or returning condensate produced from condensing steam produced by the boiler. The boiler feed pumps consume a large fraction of the auxiliary power used internally within a power plant. Boiler feed pumps can require power in excess of 10 MW on a 500–MW power plant. Therefore, the maintenance on these pumps should be rigorous to ensure both reliability and high-efficiency operation Boiler feed pumps wear over time and subsequently operate below the original design efficiency. The most pragmatic remedy is to rebuild a boiler feed pump in an overhaul or upgrade.

c. Air Heater and Duct Leakage Control

The air pre-heater is a device that recovers heat from the flue gas for use in pre-heating the incoming combustion air (and potentially for other uses such as coal drying). Properly operating air pre-heaters play a significant role in the overall efficiency of a coal-fired EGU. A major difficulty associated with the use of regenerative air pre-heaters is air leakage from the combustion air side to the flue gas side. Air leakage affects boiler efficiency due to lost heat recovery and affects the axillary load since any leakage requires additional fan capacity. The amount of air leaking past the seals tends to increase as the unit ages. Improvements to seals on regenerative air pre-heaters have enabled the reduction of air leakage.

d. Variable Frequency Drives (VFDs)

VFD on ID Fans. The increased pressure required to maintain proper flue gas flow through add-on air pollutant control equipment may require additional fan power, which can be achieved by an induced draft (ID) fan upgrade/replacement or an added booster fan. Generally, older power plant facilities were designed and built with centrifugal fans.

The most precise and energy-efficient method of flue gas flow control is use of VFD. The VFD controls fan speed electrically by using a static controllable rectifier (thyristor) to control frequency and voltage and, thereby, the fan speed. The VFD enables very precise and accurate speed control with an almost instantaneous response to control signals. The VFD controller enables highly efficient fan performance at almost all percentages of flow turndown.

Due to current electricity market conditions, many units no longer operate at base-load capacity and, therefore, VFDs, also known as variable-speed drives on fans can greatly enhance plant performance at off-peak loads. Additionally, because utilities are phasing in their environmental equipment upgrades, new fans are oversized and operated at lower capacities until all additional equipment has been added. Under these scenarios, VFDs can significantly improve the unit heat rate. VFDs as motor controllers offer many substantial improvements to electric motor power requirements. The drives provide benefits such as soft starts, which reduce initial electrical load, excessive torque, and subsequent equipment wear during startups; provide precise speed control; and enable high-efficiency operation of motors at less than the maximum efficiency point. During load turndown, plant auxiliary power could be reduced by 30–60 percent if all large motors in a plant were efficiently controlled by VFD. With unit loads varying throughout the year, the benefits of using VFDs on large-size equipment, such as FD or ID fans, boiler feedwater and condenser circulation water pumps, can have significant impacts. Because plants today usually use either new booster ID fans or new ID fans, the option of investing in VFDs generally appeals to plant operators since they are incurring long outages to install the either new or additional air emission controls equipment. There are circumstances in which the HRI has been estimated to be much higher than that shown in Table 1, depending on the operation of the unit. Cycling units realize the greatest gains representative of the upper range of HRI, whereas units which were designed with excess fan capacity will exhibit the lower range.

VFD on Boiler Feed Pumps. VFDs can also be used on boiler feed water pumps as mentioned previously. Generally, if a unit with an older steam turbine is rated below 350 MW the use of motor-driven boiler feedwater pumps as the main drivers may be considered practical from an efficiency standpoint. If a unit cycles frequently then operation of the pumps with VFDs will offer the best results on heat rate reductions, followed by fluid couplings. The use of VFDs for boiler feed pumps is becoming more common in the industry for larger units. And with the advancements in low pressure steam turbines, a motor-driven feed pump can improve the thermal performance of a system up to the 600–MW range, as compared to the performance associated with the use of turbine drive pumps. Smaller and older units will generally not upgrade to a VFD boiler feed pump drive due to high capital costs.

e. Blade Path Upgrade (Steam Turbine)

Upgrades or overhauls of steam turbines offer the greatest opportunity for HRI on many units. Significant increases in performance can be gained from turbine upgrades when plants experience problems such as steam leakages or blade erosion. The typical turbine upgrade depends on the history of the turbine itself and its overall performance. The upgrade can entail myriad improvements, all of which affect the performance and associated costs. The availability of advanced design tools, such as computational fluid dynamics (CFD), coupled with improved materials of construction and machining and fabrication capabilities have significantly enhanced the efficiency of modern turbines. These improvements in new turbines can also be utilized to improve the efficiency of older steam turbines whose efficiency has degraded over time. Upgrades or overhauls of steam turbines may offer the greatest opportunity for HRI on many units. Significant increases in performance can be gained from turbine upgrades when plants experience problems such as steam leakages or blade erosion. The typical turbine upgrade depends on the history of the turbine itself and its overall performance. The upgrade can entail myriad improvements, all of which affect the performance and associated costs.

f. Redesign/Replace Economizer

In steam power plants, economizers are heat exchange devices used to capture waste heat from boiler flue gas which is then used to heat the boiler feedwater. This use of waste heat reduces the need to use extracted energy from the system and, therefore, improves the overall efficiency or heat rate of the unit. As with most other heat transfer devices, the performance of the economizer will degrade with time and use, and power plant representatives contend that economizer replacements are often delayed or avoided due to concerns about triggering NSR requirements. In some cases, economizer replacement projects have been undertaken concurrently with retrofit installation of selective catalytic reduction (SCR) systems because the entrance temperature for the SCR unit must be controlled to a specific range.

2. Potential HRI Measures—Best Operating and Maintenance Practices

Many unit operators can achieve additional HRI by adopting best operating and maintenance practices. The amount of achievable HRI will vary significantly from unit to unit. In setting a standard of performance for a specific unit or subcategory of units, states should consider the opportunities for HRI from the following actions.

a. Adopt HRI Training for O&M Staff

EGU operators can obtain HRI by adopting ''awareness training'' to ensure that all O&M staff are aware of best practices and how those practices affect the unit's heat rate.

b. Perform On-Site Appraisals To Identify Areas for Improved Heat Rate Performance

Some large utilities have internal groups that can perform on-site evaluations of heat rate performance improvement opportunities. Outside (*i.e.,* third party) groups can also provide site-specific/unit-specific evaluations to identify opportunities for HRI.

c. Improved Steam Surface Condenser—Cleaning

Effective operation of the steam surface condenser in a power plant can significantly improve a unit's heat rate. In fact, in many cases it can pose the most significant hindrance to a plant trying to maintain its original design heat rate. Since the primary function of the condenser is to condense steam flowing from the last stage of the steam turbine to liquid form, it is most desirable from a thermodynamic standpoint that this occurs at the lowest temperature reasonably feasible. By lowering the condensing temperature, the backpressure on the turbine is lowered, which improves turbine performance.

Condenser Cleaning. A condenser degrades primarily due to fouling of the tubes and air in-leakage. Tube fouling leads to reduced heat transfer rates, while air in-leakage directly increases the backpressure of the condenser and degrades the quality of the water. Condenser tube cleaning can be performed using either on-line methods or more rigorous off-line methods. A full economic analysis should be performed to determine which off-line cleaning method is to be used. Such an analysis would result in an optimum offline or reduced-load cleaning schedule that could average between two and three cleanings a year. These analyses consider inputs such as operating data, plant performance, loads, time of year, etc., to accurately assess cleaning schedules for optimum economic performance.

3. Cost of HRI

a. Reasonableness of Cost

As mentioned earlier, under CAA section 111(a)(1), EPA is required to determine ''the best system of emission reduction which (taking into account the cost . . .) . . . has been adequately demonstrated.'' In several cases, the D.C. Circuit has elaborated on this cost factor in various ways, stating that EPA may not adopt a standard for which costs would be ''exorbitant,'' [20] ''greater than the industry could bear and survive,'' [21] ''excessive,'' [22] or ''unreasonable.'' [23] These formulations appear to be synonymous and suggest a cost-reasonableness standard. Therefore, in this action, EPA has evaluated

[20] *Lignite Energy,* 198 F.3d at 933.

[21] *Portland Cement,* 513 F.2d at 508.

[22] *Sierra Club,* 657 F.2d at 343.

[23] *Id.*

whether the costs of HRI are considered to be reasonable.

Any efficiency improvement made by an EGU will also reduce the amount of fuel consumed per unit of electricity output; fuel costs can account for as much as 70 percent of production costs of power. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving HRIs after any savings from reduced fuel expenses. So, over some time period (depending upon, among other factors, the extent of HRIs, the cost to implement such improvements, and the unit utilization rate), the savings in fuel cost associated with HRIs may be sufficient to cover the costs of implementing the HRI measures. Thus, the net costs of HRIs associated with reducing CO_2 emissions from affected EGUs can be relatively low depending upon each EGUs' individual circumstances. It should be noted that this cost evaluation is not an attempt to determine the affordability of the HRI in a business or economic sense (*i.e.,* the reasonableness of the imposed cost is not determined by whether there is an economic payback within a predefined time period). However, the ability of EGUs to recoup some of the costs of HRIs through fuel savings supports a finding that cost recovery is a reasonable factor in determining cost effectiveness.[24]

Most often, when evaluating costs for criteria pollutants—in a BACT analysis, for example—the emphasis is focused on the cost of control relative to the amount of pollutant removed—a metric typically referred to as the ''cost-effectiveness.'' There have been relatively few BACT analyses evaluating GHG reduction technologies for coal-fired EGUs; and, therefore not a large number of GHG cost-effectiveness determinations to compare against as a measure of the cost reasonableness. Nevertheless, in PSD and Title V permitting guidance for GHG emissions, EPA noted that ''it is important in BACT reviews for permitting authorities to consider options that improve the overall energy efficiency of the source or modification—through technologies, processes and practices at the emitting unit. In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per unit of output basis.'' [25] EPA has also noted that a ''number of energy efficiency technologies are available for application to both existing and new coal-fired EGU projects that can provide incremental step improvements to the overall thermal efficiency.'' [26]

b. Cost of the HRI Candidate Technologies Measures

The estimated costs for the BSER candidate technologies are presented below in Table 2. These are cost ranges from the 2009 S&L Study [27] updated to $2016. These costs correspond to ranges of HRI (percent) presented earlier in Table 1.

TABLE 2—SUMMARY OF COST ($2016/KW) OF HRI MEASURES

HRI measure	<200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	4.7	4.7	2.5	2.5	1.4	1.4
Boiler Feed Pumps	1.4	2.0	1.1	1.3	0.9	1.0
Air Heater & Duct Leakage Control	3.6	4.7	2.5	2.7	2.1	2.4
Variable Frequency Drives	9.1	11.9	7.2	9.4	6.6	7.9
Blade Path Upgrade (Steam Turbine)	11.2	66.9	8.9	44.6	6.2	31.0
Redesign/Replace Economizer	13.1	18.7	10.5	12.7	10.0	11.2
Improved O&M Practices	Minimal capital cost.					

In the CPP, EPA estimated the potential national average net HRI by coal-fired EGUs to between 2.1 to 4.3 percent for each interconnection, or about 4 percent nationally, with the improvements coming from some combination of best operating practices and equipment upgrades. The Agency noted in the CPP that the maximum cost of HRI from Table 2 is expected to be less than the $100/kW value used in the CPP proposal, especially as the EGU size increases; and, therefore, the Agency assessed the economic effects of HRI costs that might range from $50 to $100/kW. The technical applicability and efficacy of HRI measures and the cost of implementing them are dependent upon site specific factors and can vary widely from site to site. Because there is inherent flexibility provided to the states in applying the standards of performance, there is a wide range of potential outcomes that are highly dependent upon how the standards are applied (and to what degree states take into consideration other factors, including remaining useful life).

In the RIA accompanying this proposal, the Agency evaluates three illustrative scenarios that recognize the inherent flexibility provided to states in applying standards of performance and provide insight on potential outcomes. For those illustrative scenarios, EPA evaluates costs ranging from $50/kW to $100/kW. EPA requests comment, with analysis, on other cost ranges that may be appropriate.

4. Nonair Quality Health and Environmental Impacts, Energy Requirements, and Other Considerations

As directed by CAA section 111(a)(1), EPA has taken into account nonair quality health and environment requirements, and energy requirements for each of the candidate BSER technologies listed in Tables 1 and 2. None of the candidate technologies, if implemented at a coal-fired EGU, would be expected to result in any deleterious effects on any of the liquid effluents (*e.g.,* scrubber liquor) or solid by-products (*e.g.,* ash, scrubber solids). All of these candidate technologies, when

[24] While some EGUs may not realize the full potential of cost recuperation from fuel savings, we expect that the net costs of implementing heat rate improvements as an approach to reducing CO_2 emissions from fossil fuel-fired EGUs are reasonable.

[25] See page 21, ''PSD and Title V Permitting Guidance for Greenhouse Gases,'' EPA–457/B–11–001, March 2011; *https://www.epa.gov/sites/production/files/2015-12/documents/ghgpermittingguidance.pdf.*

[26] See page 25, ''Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units,'' October 2010; *https://www.epa.gov/sites/production/files/2015-12/documents/electricgeneration.pdf.*

[27] ''Coal-Fired Power Plant Heat Rate Reductions'' Sargent & Lundy report SL–009597 (2009) *https://www.epa.gov/sites/production/files/2015-08/documents/coalfired.pdf.*

implemented, would have the effect of improving the efficiency of the coal-fired EGUs to which they are applied. As such, the EGU would be expected to use less fuel to produce the same amount of electricity as it did prior to the efficiency (heat rate) improvement. None of candidate technologies is expected to impose any significant additional auxiliary energy demand.

Implementation of heat rate improvement measures also would achieve reasonable reductions in CO_2 emissions from affected sources in light of the limited cost-effective and technically feasible emissions control opportunities. In the same vein, because existing sources face inherent constraints that new sources do not, existing sources present different, and in some ways more limited, opportunities for technological innovation or development. Nevertheless, the proposed emissions guidelines encourage technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency.

5. Potential HRI at Existing Coal-Fired EGUs

Government agencies and laboratories, industry research organizations, engineering firms, equipment suppliers, and environmental organizations have conducted studies examining the potential for improving heat rate in the U.S. EGU fleet or a subset of the fleet. Table 3 below provides a list of some reports, case studies, and analyses about HRI opportunities in the United States. EPA is seeking comment on how these studies (and any others that the Agency should be aware of) can inform our understanding of potential HRI opportunities (Comment C–8).

TABLE 3—HRI REPORTS, CASE STUDIES, AND ANALYSES

HRI report organization/publication (author, if known)—title—year [URL]
Government Studies:
Congressional Research Service (Campbell)—Increasing the Efficiency of Existing Coal-fired Power Plants (R43343)—2013 [https://fas.org/sgp/crs/misc/R43343.pdf].
EIA—Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants—2015 [https://www.eia.gov/analysis/studies/powerplants/heatrate/pdf/heatrate.pdf].
EPA—Greenhouse Gas Mitigation Measures—2015 [https://www.regulations.gov/document?D=EPA-HQ-OAR-2013-0602-37114].
NETL—Opportunities to Improve the Efficiency of Existing Coal-fired Power Plants—2009 [http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/OpportImproveEfficExistCFPP-ReportFinal.pdf].
NETL—Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States—2010 [http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ThermalEfficCoalFiredPowerPlants-TechWorkshopRpt.pdf].
NETL—Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions (DOE/NETL–2010/1411)—2010 [http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2010-1411-ImpEfficCFPPGHGRdctns-0410.pdf].
NETL—Options for Improving the Efficiency of Existing Coal-Fired Power Plants (DOE/NETL–2013/1611)—2014 [https://www.netl.doe.gov/energy-analyses/temp/FY14_OptionsforImprovingtheEfficiencyofExistingCoalFiredPowerPlants_040114.pdf].
IEA (Reid)—Retrofitting Lignite Plants to Improve Efficiency and Performance (CCC/264)—2016 [http://bookshop.iea-coal.org/reports/ccc-264/83861].
IEA (Henderson)—Upgrading and Efficiency Improvement in Coal-fired Power Plants (CCC/221)—2013 [http://bookshop.iea-coal.org/reports/ccc-221/83186].
European Commission—Integrated Pollution Prevention and Control Reference Document on Best Available Techniques for Large Combustion Plants—2006 [http://eippcb.jrc.ec.europa.eu/reference/BREF/lcp_bref_0706.pdf].
Industry/Industrial Groups:
EPRI—Range of Applicability of Heat Rate Improvements—2014 [https://www.epri.com/#/pages/product/000000003002003457].
ABB Power Generation—Energy Efficient Design of Auxiliary Systems in Fossil-Fuel Power Plants [https://library.e.abb.com/public/5e627b842a63d389c1257b2f002c7e77/Energy%20Efficiency%20for%20Power%20Plant%20Auxiliaries-V2_0.pdf].
Alstom Engineering (Sutton)—CO_2 Reduction Through Energy Efficiency in Coal-Fired Boilers—2011 [http://www.mcilvainecompany.com/Universal_Power/Subscriber/PowerDescriptionLinks/Jim%20Sutton%20-%20Alstom%20-%203-31-2011.pdf].
GE—Comments of the General Electric Company—2014 [https://www.regulations.gov/document?D=EPA-HQ-OAR-2013-0602-22971].
National Petroleum Council—Electric Generation Efficiency—2007 [http://www.npc.org/Study_Topic_Papers/4-DTG-ElectricEfficiency.pdf].
S&L—Coal-fired Power Plant Heat Rate Reductions (SL–009597)—2009 [https://www.regulations.gov/document?D=EPA-HQ-OAR-2013-0602-36895].
S&L—Coal Fired Power Plant Heat Rate Reduction—NRECA (SL–012541)—2014 [https://www.regulations.gov/document?D=EPA-HQ-OAR-2013-0602-22767 Supp 33].
Storm Technologies—Applying the Fundamentals for Best Heat Rate Performance of Pulverized Coal Fueled Boilers—2009 [http://www.stormeng.com/pdf/EPRI2009HeatRateConference%20FINAL.pdf].
Environmental Groups/Academic Studies:
Lehigh University—Reducing Heat Rates of Coal-fired Power Plants—2009 [http://www.lehigh.edu/~inenr/leu/leu_61.pdf].
NRDC—Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters (12–11–A)—2013 [https://www.nrdc.org/sites/default/files/pollution-standards-report.pdf].
Resources for the Future (Lin *et al.*)—Regulating Greenhouse Gases from Coal Power Plants Under the Clean Air Act (RFF–DP–13–05)—2014 [http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-DP-13-05.pdf].
Sierra Club (Buckheit & Spiegel)—Sierra Club 52 Unit Study—2014 [http://content.sierraclub.org/environmentallaw/sites/content.sierraclub.org.environmentallaw/files/Appendix%201%20-%20Rate%20v%20Load%20Summary.pdf].
Other Publications:
Power Engineering International (Co_X)—Dry Sorbent Injection for SO_X Emissions Control—2017 [http://www.powerengineeringint.com/articles/print/volume-25/issue-6/features/dry-sorbent-injection-for-sox-emissions-control.html].
Power Mag (Korellis)—Coal-Fired Power Plant Heat Rate Improvement Options, Parts 1 & 2—2014 [http://www.powermag.com/coal-fired-power-plant-heat-rate-improvement-options-part-2] [http://www.powermag.com/coal-fired-power-plant-heat-rate-improvement-options-part-1].
Power Mag (Peltier)—Steam Turbine Upgrading: Low-hanging Fruit—2006 [http://www.powermag.com/steam-turbine-upgrading-low-hanging-fruit].

It has been noted that unit-level HRIs, with the resulting reductions in variable operating costs at those improved EGUs, could lead to increases in utilization of those EGUs as compared to other generating options (*i.e.,* ''rebound effect''). *See generally* 80 FR 64745.

As part of the cost-benefit analysis in the RIA for this proposed action, EPA modeled a range of potential HRIs (percent improvement, as described in the RIA). The results of the modeling, for the years of analysis for this rule, predict that there will be no cumulative increases in system-wide emissions relative to a scenario where no action is taken. While the RIA shows that, under certain assumptions, sources that adopt HRI may increase generation, due to their improved efficiency and relatively improved economic competitiveness, they also generally reduce emissions (as a group) because they can generate higher levels of electricity with a lower overall emission rate. Hence, EPA analysis indicates that the system-wide emission decreases due to reduced heat rate are likely to be larger than any system-wide increases due to increased operation. EPA solicits comment on this conclusion (Comment C–9).

C. HRI for Natural Gas-Fired Stationary Combustion Turbines

EPA has also considered opportunities for emission reductions at natural gas-fired stationary combustion turbines as a part of the BSER—at both simple cycle turbines and combined cycle turbines—and previously determined that the available emission reductions would likely be expensive or would likely provide only small overall reductions relative to those that were predicted through application of other systems of emission reduction identified in the CPP building blocks. In the development of the CAA section 111(b) standards of performance for new, modified, and reconstructed EGUs, several commenters provided information on options that may be available to improve the efficiency of existing natural gas-fired stationary combustion turbines. *See* 80 FR 64620. Commenters—including turbine manufacturers—described specific technology upgrades for the compressor, combustor, and gas turbine components that operators of existing combustion turbines may deploy. The commenters noted that these state-of-the-art gas path upgrades, software upgrades, and combustor upgrades have the potential to reduce GHG emissions by a significant amount. In addition, one turbine 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 margin. *See* 80 FR 64620.

In addition to upgrades to the combustion turbine, the operator of a NGCC unit may have the opportunity to improve the efficiency of the heat recovery steam generator and steam cycle using retrofit technologies that may reduce the GHG emissions by 1.5 to 3 percent. These include: (1) Steam path upgrades that 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 the ANPRM, EPA requested comment on the broad availability and applicability of any HRIs for natural gas combustion turbine EGUs. EPA also solicited comment on the Agency's previous determination in the CPP that the available GHG emission reduction opportunities would likely provide only small overall GHG reductions as compared to those from HRIs at existing coal-fired EGUs. *See* 80 FR 64756.

Several commenters suggested that there are significant opportunities for emission reductions via HRIs at natural gas combined cycle EGUs while many other commenters contended that any such emission reductions would be minimal and too expensive. Still, other commenters noted that operational changes—such as lower capacity factor or fluctuations in load (cycling)—affect the heat rate and make it difficult to accurately gauge the availability of HRI opportunities for NGCC EGUs.

However, while numerous comments suggested that there are available HRI opportunities at existing NGCC EGUs, no commenters provided specific information on the availability, applicability, or cost of HRI opportunities for NGCC units—nor did any commenters provide any information on the magnitude of expected heat rate reductions.

To assess potential HRI of existing NGCC EGUs, EPA looked at 11 years of historical gross heat rate data from 2007 to 2017 for existing NGCC EGUs that reported both heat input and gross electricity output to the Agency in 2017. The Agency used the 2007 to 2016 data to calculate a ''benchmark'' heat rate for each unit. EPA evaluated the HRI potential using an approach that is similar to the method used to determine a unit-specific standard that was finalized for modified coal-fired EGUs. The Agency evaluated the HRI potential by comparing the 2017 national annual heat rate with the best annual heat rate in the years from 2007 to 2016 year. The HRI potential was calculated nationally and at each regional interconnection: East, West, and Texas. Nationally the HRI evaluation suggested an average HRI potential of 3.4 percent.

EPA also conducted a literature search and found some papers suggesting potential for improvement in the heat rate. The literature suggested that most HRIs would be accompanied by commensurate capacity increases.[28] EPA takes comment on the estimates in this paper and is seeking any other information commenters have about the performance and cost of potential HRIs for turbines (Comment C–10). We also take comment on whether if EPA determined that HRIs in that range were available for similar costs, it would be appropriate for EPA to reconsider its determination that there are no HRIs that represent the BSER (Comment C–11).

D. Other Considered Systems of GHG Emission Reductions

EPA also considered other systems of GHG emission reductions that may be applied to affected EGUs but is not proposing that they should be part of the BSER for the reasons discussed below. EPA acknowledges that there may be other methods and technologies suitable for adoption at some specific sources, but states and sources are best suited to determine if those alternative measures and technologies are appropriate and/or allowable compliance measures.

1. Carbon Capture and Storage (CCS) [29]

EPA has previously determined that CCS (or partial CCS) should not be a part of the BSER for existing fossil fuel-fired EGUs because it was significantly more expensive than alternative options for reducing emissions and may not be a viable option for many individual facilities. *See* 80 FR 64756. Even assuming that CAA section 111(d) may be used to project technological

[28] Phillips, J.; Levine, P.; ''Gas Turbine Performance Upgrade Options'', FERN Engineering Paper, available at *http://www.fernengineering.com/pdf/gt_upgrade_options.pdf.*

[29] CCS is sometimes referred to as Carbon Capture and Sequestration. It is also sometimes referred to as CCUS or Carbon Capture Utilization and Storage (or Sequestration), where the captured CO_2 is utilized in some useful way and/or permanently stored (for example, in conjunction with enhanced oil recovery). In this document, we consider these terms to be interchangeable and for convenience will exclusively use the term CCS.

advances, EPA must balance innovative technologies against their economic, energy, nonair health and environmental impacts. EPA continues to believe that neither CCS nor partial CCS are technologies that can be considered the BSER for existing fossil fuel-fired EGUs. However, if there is any new information regarding the availability, applicability, costs, or technical feasibility of CCS technologies, commenters are encouraged to provide that information to EPA (Comment C–12).

Similarly, EPA considered whether CCS or partial CCS should be the BSER for natural gas-fired stationary combustion turbines and have determined that, currently, the technology is exorbitantly expensive, has not been adequately demonstrated, and would not be available for a large number of existing sources. Similar technologies—such as use of the novel Allam Cycle[30]—are, while seemingly promising, still in the early demonstration phase.

2. Fuel Co-Firing

EPA has previously determined that co-firing of alternative fuels (biomass or natural gas) in coal-fired utility boilers is not part of BSER for existing fossil fuel-fired sources due to cost and feasibility considerations. *See* 80 FR 64756. Although some fuel co-firing methods are technically feasible for some affected sources, there are factors and considerations that prevent its inclusion as BSER. In general, fuel use opportunities are dependent upon many regional considerations and characteristics (*e.g.,* access to biomass, or natural gas pipeline infrastructure limitations), that prevent its adoption as BSER on a national level (whereas nearly all sources can or have implemented some form of heat rate improvement measures). Another important factor is cost, and broader application of fuel co-firing methods has been shown to be costly. While this proposal does not include fuel co-firing methods as BSER, EPA proposes that they be allowed as compliance options that states may consider (see Section VI). EPA solicits comment, nevertheless, on whether co-firing methods should be included among the list of BSER candidate technologies for states to evaluate when establishing a standard of performance for each affected source in their jurisdiction.

a. Natural Gas Co-Firing

Coal-fired power plants typically use natural gas or other clean fuel (such as low sulfur fuel oil) for start-up operations and, if needed, to maintain the unit in ''warm stand-by.'' Some plants co-fire natural gas simultaneously with coal—either directly as a combustion fuel or in configuration referred to as natural gas reburn, which is used for NOx control. During periods of natural gas co-firing, an EGU's CO_2 emission rate is reduced as natural gas is a less carbon intensive fuel than coal. For example, at 10 percent natural gas co-firing, the net emissions rate (lb/MWh-net) of a typical unit would decrease by approximately 4 percent. On the other hand, co-firing can negatively impact a unit's efficiency due to the high hydrogen content of natural gas and the resulting production of water as a combustion by-product. And depending on the design of the boiler and extent of modifications, some boilers may be forced to de-rate (a reduction in generating capacity) in order to maintain steam temperatures at or within design limits, or for other technical reasons.

In evaluating BSER technology options, CAA section 111(a)(1) directs EPA to take into account nonair quality health and environmental impacts, and energy requirements. EPA is unaware of any significant nonair quality health or environmental impacts associated with natural gas co-firing. However, in taking energy requirements into account, EPA notes that co-firing natural gas in coal-fired utility boilers is not the best, most efficient use of natural gas and, as noted above, can lead to inefficient operation of utility boilers. NGCC stationary combustion turbine units are much more efficient at using natural gas as a fuel for the production of electricity and it would not be an environmentally positive outcome for utilities and owner/operators to redirect natural gas from the more efficient NGCC EGUs to the less efficient coal-fired EGUs in order to satisfy an emission standard at the coal-fired unit.

Moreover, unlike coal, natural gas cannot be stored in quantities sufficient for sustained utilization on site. Accordingly, delivery of natural gas via pipeline is essential for using natural gas at coal-fired EGUs. Many existing coal-fired plants, however, do not have access to natural gas transportation infrastructure and gaining access would be either infeasible (due to technical or timing considerations) or unreasonably costly.[31] For plants that currently co-fire natural gas and have access to an existing natural gas pipeline, many may be capacity constrained (*i.e.,* they are not able to greatly increase purchase volumes with the existing infrastructure). Accordingly, although natural gas fuel prices are currently low and some sources currently co-fire natural gas, on balance, there are notable challenges and concerns with instituting natural gas co-firing on a wide variety of units across the country. Therefore, EPA is not proposing that natural gas co-firing should be part of the BSER.

b. Co-Firing Biomass

The infrastructure, proximity and cost aspects of co-firing biomass at existing coal EGUs are similar in nature and concept to those of natural gas. While there are some existing coal-fired EGUs that currently co-fire with biomass fuel, those are in relatively close proximity to cost-effective biomass supplies; and, there are regional supply and demand dynamics at play. As with the other emission reduction measures discussed in this section, EPA expects that use of some types of biomass may be economically attractive for certain individual sources. However, on a broader scale, biomass co-firing is more expensive and/or less achievable than the measures determined to be part of the BSER. As such, EPA is not proposing that the use of biomass fuels is part of the BSER because too few individual sources will be able to employ that measure in a cost-reasonable manner.

VI. State Plan Development

A. Establishing Standards of Performance

1. Application of the BSER

As discussed in Section III above, EPA has the authority to determine the BSER as part of regulations it promulgates pursuant to CAA section 111(d)(1) (providing that states shall submit plans to EPA establishing ''standards of performance'' for existing sources); *see also* CAA section 111(a)(1) (defining ''standard of performance'' with reference to the ''best system of emission reduction which . . . the Administrator determines has been adequately demonstrated''). For such regulations, EPA has traditionally promulgated emission guidelines governing the process for states to

[30] *https://www.netpower.com/.*

[31] In addition to new pipeline infrastructure, conversion to natural gas co-firing in a coal-fired boiler typically involves installation of new gas burners and supply piping, modifications to combustion air ducts and control dampers, and possibly modifications to the boiler's steam superheater, reheater, and economizer heating surfaces that transfer heat from the hot flue gas exiting the boiler furnace. The conversion may also involve modification and possible deactivation of some downstream air pollution emission control equipment.

submit plans which establish standards of performance which reflect the degree of emission limitation achievable through application of the BSER to each affected source within the state, in addition to the implementing regulations EPA initially promulgated in 1975 to set the general framework under which it would administer section 111(d). The implementing regulations that are also being proposed in this action (see Section VII below for a discussion on the proposed new implementing regulations) contain certain requirements for EPA in promulgating an emission guideline under section 111(d). One requirement of the new proposed implementing regulations (consistent with the previous implementing regulations and section 111(d) of the CAA) is that an EPA-promulgated emission guideline provide information on the degree of emission reduction which is achievable with each system, together with information on the costs, and nonair health and environmental effects, and energy requirements of applying each system to designated facilities.[32] This means that EPA will provide, in addition to the BSER, *information* on the degree of emission reduction that is achievable when the BSER is applied. In the case of this proposed rulemaking and as described above in Section V, EPA is proposing that the BSER is HRI made at the unit level. To meet the requirements of the new proposed implementing regulations, EPA is proposing candidate technologies for HRI measures corresponding to a range of reductions and costs as information regarding the degree of emission reduction achievable through application of the BSER. Because affected EGUs in each state are different and the application of different HRI measures may take into account source-specific factors, EPA is providing expected ranges of HRIs. These ranges are shown in Table 1.

EPA expects that states can use the information that EPA provides on the degree of emission limitation in developing standards of performance for affected EGUs as part of establishing a standard of performance for inclusion in a state's plan pursuant to the requirements of section 111(d)(1). In this case, the ranges of HRIs are provided as guidance for states to use in evaluating the efficacy of implementing each measure identified as part of the BSER candidate technologies at each affected EGU. While the HRI potential range is provided as guidance for the states, the actual HRI performance for each of the candidate technologies will be unit-specific and will depend upon a range of unit-specific factors. The states will use the information provided by EPA as guidance, but will be expected to conduct unit-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies. Once a state evaluates the HRIs identified as part of the BSER in establishing a standard of performance for a particular affected EGU, it is within the state's discretion to take certain factors concerning that source, such as remaining useful life, into consideration when determining how the standard of performance should be applied. The next section describes how states may derive a standard of performance reflecting the degree of emission limitation achievable through application of the BSER.

Additionally, the new proposed implementing regulations require that an emission guideline identify information such as a timeline for compliance with standards of performance that reflect the application of the BSER. *See* proposed 40 CFR 60.22a. However, given the source-specific nature of this proposed emission guideline and reasonably anticipated variation between standards established for sources within a state, EPA believes it more appropriate that a state establish tailored compliance deadlines for its sources based on the standard ultimately determined for each source. Accordingly, the EPA proposes to supersede this aspect of proposed 40 CFR 60.22a, as allowed under the applicability provision under proposed 60.20a, and allow for states to include appropriate compliance deadlines for sources based on the standards of performance determined as part of the state plan process.

EPA is proposing, consistent with the new proposed implementing regulations (subpart Ba), that states will include custom compliance schedules for affected EGUs as part of their state plan. This is another area that states have latitude for taking into account unit specific factors. It should be noted however, that per the proposed new implementing regulations, if a state chooses to include a compliance schedule for a source that extends more than twenty-four months from the submittal of the state plan, the plan must also include legally enforceable increments of progress for that source (*See* proposed 40 CFR 60.24a(d)(1)). The EPA solicits comment on whether states should determine source-specific compliance schedules under this emission guideline, or if a uniform compliance schedule is appropriate, and if so, what length of time is appropriate. (Comment C–13).

2. Determination of a Unit's Standard of Performance

As described in other parts of this section, while EPA's role is to determine the BSER, section 111(d)(1) squarely places the responsibility of establishing a standard of performance for an existing source on the state as part of developing a state plan. EPA is proposing that once EPA determines the BSER, states are expected to evaluate each of the BSER HRI measures that EPA has determined represent BSER in establishing a standard of performance for each source within their jurisdiction. The states, in applying the standards of performance, may take into consideration, among other factors, the remaining useful life of the existing source to which the standard would apply (see Section VI.B.1 for further discussion on remaining useful life and other factors). The proposed BSER is a list of candidate technologies that are HRI measures, which states should evaluate, and potentially apply to existing sources as appropriate based upon the specific characteristics of those units. In general, EPA envisions that, under the proposed program, the states would set standards based on considerations most appropriate to individual sources or groups of sources (*e.g.,* subcategories). These may include consideration of historical emission rates, effect of potential HRIs (informed by the information in EPA's candidate technologies described earlier in Section V), or changes in operation of the units, among other factors the state believes are relevant. As such, states have considerable flexibility in determining emission standards for units, as contemplated by the express statutory text.

Several commenters on the ANPRM suggested that EPA should develop a default methodology for determining appropriate standards of performance that are consistent with the BSER. More specifically, commenters suggested that EPA should use a methodology that is similar to the one finalized for major modifications at coal-fired EGUs under the section 111(b) program—*i.e.,* based on the use of historical heat rate or emissions data for the individual

[32] This is consistent with the statutory definition of ''standard of performance'' at CAA section 111(a)(1) (emphases added): ''a standard for emissions of air pollutants which reflects the *degree of emission limitation achievable* through the application of the best system of emission reduction which (*taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements*) the Administrator determines has been adequately demonstrated.''

source. Commenters also suggested that any approach covering all existing units should use at least ten years' worth of historical data and should be based on rolling averages for multiple year periods (*e.g.,* the fourth highest three-year average during the historical look-back period). Other commenters suggested that the approach used for major modifications was too stringent to apply to all units. EPA understands that if the Agency were to provide a specific and presumptively-approvable methodology for establishing standards of performance, that approach would provide states with certainty in how to develop plans. EPA is not proposing a specific methodology or formula for establishing standards of performance for existing sources in this action. EPA believes that such a presumptive standard could be viewed as limiting a state's ability to deviate from the prescribed methodology and that the approach could ultimately be more limiting than helpful. While EPA is not proposing a presumptive formulaic approach in this action, the Agency is soliciting comment on approaches based on the use of historical heat rate or emissions data for the individual source (Comment C–14). The circumstances and considerations for establishing standards of performance under CAA 111(b) for affected sources that have undergone a modification (*i.e.,* any physical change in or change in the method of operation that increases the hourly emissions of GHG) are not the same as the circumstances and considerations for states should take into account in establishing standards of performance under these proposed emission guidelines, but there are certainly parallels and similarities.

As mentioned earlier, states may take into consideration other factors, including remaining useful life, when applying unit-specific standards of performance. Consideration of these factors may result in the application of the standard of performance in a less stringent manner than would otherwise be suggested by strict implementation of the BSER technologies. This topic is discussed in detail in Section VI.B.

As previously described, this proposal seeks to clarify the Agency's and states' roles under section 111(d). The statute is clear that EPA determines the BSER, and states submit plans that establish standards of performance for existing sources that, under the definition of ''standard of performance in CAA section 111(a)(1), reflect the degree of emission limitation achievable though the application of the BSER. Consistent with the statute, EPA's proposed implementing regulations at 40 CFR 60.22a(b)(2) specify that an emission guideline must include *information* on the degree of emission reduction which is achievable, but does not require that EPA must provide a standard of performance that presumptively reflects such degree of emission reduction which is achievable through application of the BSER, as that is appropriately the states' role. EPA is proposing to clarify that the implementing regulations do not require EPA to provide a presumptive numerical standard as part of its emission guidelines and that the ranges of expected emission reductions that can be achieved in EPA's BSER determination adequately provide sufficient information to the states on the degree of emission limitation that will result from application of the BSER to existing sources to appropriately inform the states' exercise of their authority to develop plans under 111(d).

Given that section 111(d)(1) requires states to submit plans that establish standards of performance for affected sources, EPA believes it is consistent with the spirit of cooperative federalism to provide information sufficient to assist states in the development of state plans, which in turn will provide both states and sources with regulatory certainty via a plan that is approvable under section 111(d)(2) and applicable regulations. As mentioned above, EPA is proposing to provide information regarding ranges of expected reductions associated with the various HRIs identified as the BSER, which will assist states in establishing appropriate standards of performance for affected EGUs. EPA proposes to determine providing such information is consistent with both the implementing regulations at 40 CFR 60.22(b) and CAA section 111(d) regarding the roles of states and EPA determining the degree of emission limitation achievable through application of the BSER.

As described below in Section VI.B, under the statute, the proposed new implementing regulations, and these proposed emission guidelines, states have considerable flexibility in developing their plans and establishing and applying standards of performance to existing sources. One of the areas of flexibility described is in the standard setting process for EGUs. As part of this flexibility, EPA is proposing that states should have broad flexibility on whether and how the state chooses to group, sort, or subcategorize affected EGUs within the state to establish standards of performance. In evaluating affected EGUs, if a state finds that there is an overlap in circumstances around a group of EGUs, it might make sense to implement a uniform methodology for setting a standard of performance across that group. Another area of flexibility is explicitly provided in the statutory text of 111(d)(1) itself. The statute requires that EPA's regulations implementing section 111(d) shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

3. Forms of Standards of Performance

As described further in Section VII.C of this preamble, EPA is proposing a new implementing regulation for section 111(d) which includes a proposed definition of ''standard of performance that aligns with the statutory definition of the term under CAA section 111(a)(1). EPA is further proposing, as part of the new implementing regulations, that a specific emission guideline may contain provisions that supersede the applicability of the implementing regulations. In the context of these emission guidelines, EPA is proposing that an allowable emission rate (*i.e.,* rate-based standard in, for example, lb CO_2/MWh-gross) be the form of standard of performance that states would include in their state plans for affected EGUs. Primarily, an allowable emission rate most closely aligns to EPA's BSER determination for these emission guidelines. When HRIs are made at an EGU, by definition, the CO_2 emission rate will decrease as described above in Section V.B. There is a natural correspondence between the BSER and an allowable emission rate as the standard of performance in this action. Secondly, EPA is proposing that state plans include only the one form of standard of performance (*i.e.,* proposing only an allowable emission rate) to create continuity across states, prevent ambiguity, and to ensure as much simplicity as possible. However, EPA solicits comment on whether other forms of standards of performance should be allowed in state plans and whether a different form of standard should be the primary form that is authorized for state plans under a final emission guideline in response to this proposal (Comment C–15).

EPA is proposing an allowable emission rate of CO_2 as the form of the standard of performance because it creates the most straightforward system for states to determine standards and ensure compliance. This also creates a more streamlined evaluation for EPA to consider in state plan evaluation as there are fewer variables to consider (*e.g.,* projections of utilization which would be required if the standard of performance took a mass-based form).

4. Gross Versus Net Emission Standards

EPA also requests comment on the merits of differentiating between gross and net heat rate (Comment C–16). This may be particularly important when considering the effects of part load operations (*i.e.,* net heat rate would include inefficiencies of the air quality control system at a part load whereas gross heat rate would not). This will also be important in recognizing the improved efficiency obtained from upgrades to equipment that reduce the auxiliary power demand.

B. Flexibilities for States and Sources

Once EPA determines the BSER, section 111(d)(1) of the CAA requires that ''each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source [. . .], and (B) provides for the implementation and enforcement of such standards of performance.'' Section 111(d)(1) further requires EPA to ''permit the State in applying a standard of performance to any particular source under a plan [. . .] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.''

In light of the cooperative-federalist structure of section 111(d) and its express language requiring that EPA allow states to take into account source-specific factors when establishing standards of performance for existing sources, EPA believes it is appropriate in this proposal to provide considerable flexibility for states to set standards of performance for units and also allow states to have considerable latitude for implementing measures and standards for affected EGUs. A detailed discussion of the flexibility that states have in developing standards of performance is provided below in Section VI.B.1. States also have flexibility in the measures and processes that they put in place for affected EGUs to meet their compliance obligations. One of the examples of this is discussed in Section VI.B.2 on averaging and trading. As previously discussed, the BSER's candidate technologies affords states considerable flexibility to determine how to apply standards of performance to affected sources. Several commenters noted in the ANPRM that flexibility for States and affected sources should be part of any replacement rule, with States being able to choose from a wide variety of possible methods for developing a standard of performance, along with options for how to implement the standard through their state plans. Other commenters suggested that any flexible compliance opportunities provided should be directly linked to the determination of the BSER, such that increased compliance flexibility in the state's establishment of a standard of performance for an existing source can only be included to the extent that the flexibility is included as part of the BSER.

Another important and distinctly different element of flexibility in this proposal is the availability of compliance options for affected sources in meeting their standards of performance. To the extent that a state develops a standard of performance for an affected source within its jurisdiction, the state is free to give the source flexibility to meet that standard of performance using either BSER technologies or some other non-BSER technology or strategy. In other words, an affected source may have broad discretion in meeting its standard of performance within the requirements of a state's plan. For example, there are technologies, methods, and/or fuels that can be adopted at the affected source to allow the source to comply with its standard of performance that were not determined to be the BSER, but which may be applicable and prudent for specific units to use to meet their compliance obligations. Examples of non-BSER technologies and fuels include HRI technologies that were not included as candidate technologies, CCS, and fuel co-firing (natural gas or certain biomass). In keeping with past programs that regulated affected sources using a standard of performance, EPA takes no position regarding whether there may be other methods or approaches to meeting such a standard, since there are likely various approaches to meeting the standard of performance that EPA is either unable to include as part of the BSER, or is unable to predict. EPA proposes that affected sources may use both BSER and non-BSER measures to achieve compliance with their state plan obligations.

To demonstrate that measures taken to meet compliance obligations for a source actually reduce its emission rate, EPA proposes that the measures should meet two criteria: (1) They are implemented at the source itself, and (2) they are measurable at the source of emissions using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be easily monitored, reported and verified at a unit. There may be other technologies or compliance measures that meet these general criteria. EPA solicits comment on whether these two criteria are appropriate or not and why, and whether there may be compliance flexibilities that might meet the two proposed criteria (Comment C–17). This proposed rule is intended to generally allow compliance flexibility in state plans where appropriate, to the extent they contribute to meeting any particular standard of performance, consistent with the criteria. EPA is further soliciting comment on whether there are certain non-BSER measures that should be disallowed for compliance, and if so, under what criteria or rationale should measures be disallowed for compliance (Comment C–18).

Section 111(d)(1)(B) additionally requires state plans to include measures that provide for the implementation and enforcement of standards of performance. EPA believes states can meet these requirements by including measures as described in Section VI.C of this proposal regarding state plan components, such as monitoring, reporting, and recordkeeping requirements. EPA solicits comments on what other implementation and enforcement measures may be necessary for states to meet the requirements of section 111(d)(1)(B) (Comment C–19). Additionally, as part of ensuring that regulatory obligations appropriately meet statutory requirements such as enforceability, EPA has historically and consistently required that obligations placed on sources be quantifiable, non-duplicative, permanent, verifiable, and enforceable. EPA is similarly proposing that standards of performance places on affected EGUs as part of a state plan be quantifiable, non-duplicative, permanent, verifiable, and enforceable.

The Agency specifically recognizes that some entities may be interested in using biomass as a compliance option for meeting the state determined emission standard.[33] As with the other non-BSER measures discussed in this section, EPA expects that use of biomass may be economically attractive for certain individual sources even though on a broader scale it may be more expensive or less achievable than the measures determined to be part of the BSER (and therefore EPA is not proposing to determine that it should be included within the BSER, which is properly limited to measures likely to be cost-reasonable for a greater proportion

[33] EPA believes that biomass co-firing can meet the two criteria above because the biomass can be burned at the source and there are different methods that can be used to monitor or calculate the amount of biogenic CO_2 emissions associated with biomass use at a unit.

of existing sources than we believe biomass to be at this time).

Certain kinds of biomass, including that from managed forests, have the potential to offer a wide range of economic and environmental benefits, including carbon benefits. However, these benefits can typically only be realized if biomass feedstocks are sourced responsibly, which can include ensuring that forest biomass is not sourced from lands converted to non-forest uses. States that intend to propose the use of forest-derived biomass for compliance by affected units may refer to EPA's April 2018 statement on its intended treatment of biogenic CO_2 emissions from stationary sources that use forest biomass for energy production.[34] [35] As discussed in the recent statement, EPA's policy is to treat biogenic CO_2 emissions resulting from the combustion of biomass from managed forests at stationary sources for energy production as carbon neutral.36 EPA will continue to evaluate the applicability of this policy of treating forest-biomass derived biogenic CO_2 as carbon neutral based on relevant information, including data from interagency partners on updated trends in forest carbon stocks.

EPA solicits comments on the inclusion of forest-derived biomass as a compliance option for affected units to meet state plan standards under this rule (Comment C–20). The Agency also solicits comment on the inclusion of non-forest biomass (*e.g.,* agricultural, waste stream-derived) for energy production as a compliance option, and what value to attribute to the biogenic CO_2 emissions associated with non-forest biomass feedstocks (Comment C–21). EPA recognizes that CCS technology (described above in this section) could be applied in conjunction with biomass use.

1. State Discretion To Consider Remaining Useful Life and Other Factors in Setting Standards of Performance

Section 111(d)(1) requires that EPA's regulations must permit states to take into account, among other factors, an affected source's remaining useful life when establishing an appropriate standard of performance. In other words, Congress explicitly envisioned under section 111(d)(1) that states could implement standards of performance that vary from EPA's emission guidelines under appropriate circumstances.

Congress explicitly mentions consideration of remaining useful life in 111(d). Ultimately remaining useful life impacts cost. When EPA develops a BSER, EPA typically considers factors such as cost relative to assumptions about a typical unit. If the remaining useful life of a particular unit is less, that will generally increase the cost of control because the time to amortize capital costs is less. When congress mentions other factors, EPA believes that these are generally other factors that may substantially increase costs relative to a more typical unit.

As such, EPA is proposing, as part of the proposed implementing regulations, to permit states to take into account remaining useful life, among other factors, in establishing a standard of performance for a particular affected source, consistent with section 111(d)(1)(B). EPA solicits comments on the manner in which states should be permitted to exercise their statutory authority to take into account remaining useful life and on what ''other factors'' might appropriately be besides remaining useful life (Comment C–22). As described in Section VII.F., EPA further proposes as part of the new implementing regulations that the following factors give meaning to section 111(d)(1)(B):

- Unreasonable cost of control resulting from plant age, location, or basic process design;
- Physical impossibility of installing necessary control equipment; or

Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable. Given that there are unique attributes and aspects of each affected source, there are important factors that influence decisions to invest in technologies to meet a potential performance standard. These include timing considerations like expected life of the source, payback period for investments, the timing of regulatory requirements, and other unit-specific criteria. The state may find that there are space or other physical barriers to implementing certain HRIs at specific units. Or the state may find that some heat rate improvement options are either not applicable or have already been implemented at certain units. EPA understands that many of these ''other factors'' that can affect the application of the BSER candidate technologies distill down to a consideration of cost. Applying a specific candidate technology at an affected EGU can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO_2 reductions. Accordingly, EPA proposes that these factors are the types that are specific to the facility (or class of facilities) that make a variance from the emission guideline significantly more reasonable, as allowed under proposed 40 CFR 60.24a(e)(3). EPA, therefore, proposes to allow states to take these factors into account in establishing a standard of performance for state plans in response to this emission guideline. EPA further solicits comments on what are other factors that states should be allowed to consider in establishing a standard of performance, per the proposed variance provision (Comment C–23).

As previously described, EPA proposes that states that utilize the proposed variance provision in the new implementing regulations to establish a less stringent standard of performance for an affected EGU and/or a compliance schedule that is longer than that contemplated in EPA's final emission guideline must demonstrate as part of their state plan submission that such application of the provision meets the criteria described in the factors in Section VII.D. EPA also recognizes that for some sources, the criteria may result in determining that no measures in the candidate technologies are applicable. Two examples of this might be a unit with a very short remaining useful life or a unit that has already implemented all of the candidate technologies of the BSER. In cases such as these, a state should still establish a standard of performance. In the case of a unit with a short remaining useful life, EPA takes comment on what such a standard might look like (Comment C–24). For instance, a state could set a standard using both an emission rate and a compliance deadline to address this instance. The emission standard would only be applicable if a source did not shut down by the compliance deadline. In the case of an affected EGU that has already implemented all of the candidate technologies, EPA would expect that a state set a standard of performance that would reflect an emission rate that is at least as stringent as ''business as usual'' for that source without allowing for any backsliding on performance. EPA requests comment on these proposed treatments of a source that either has a short remaining useful

[34] *https://www.epa.gov/sites/production/files/2018-04/documents/biomass_policy_statement_2018_04_23.pdf.*

[35] This policy statement aligns with provisions in the Consolidated Appropriations Act, 2018, which calls for EPA, the Department of Energy and the Department of Agriculture to establish policies that, consistent with their missions, jointly ''reflect the carbon-neutrality of forest bioenergy and recognize biomass as a renewable energy source, provided the use of forest biomass for energy production does not cause conversion of forests to non-forest use.'' *https://www.congress.gov/115/bills/hr1625/BILLS-115hr1625enr.pdf.*

life or has already implemented all of the HRIs identified as the BSER.

EPA is also generally soliciting comment on whether there are considerations in allowing states to utilize this proposed variance provision in the new implementing regulations in response to the final emission guideline, including the potential interaction of the compliance flexibilities proposed in this proposal with utilization of the provision (Comment C–25). For example, could states authorize trading as a compliance mechanism for affected EGUs and additionally invoke this provision, or would utilizing both trading and this provision in establishing standards in a state plan potentially result in such standards going beyond what section 111(d) permits (*i.e.,* would allowing for both trading and a variance with respect to the same standard result in a standard that is impermissibly less stringent than what application of the BSER in conjunction with invocation of this provision would result in)? EPA welcomes comments on the legality and appropriateness of utilizing this provision generally, and in the context of specific compliance flexibilities that states may employ in developing their plans (Comment C–26).

Another consideration for states in determining a standard of performance with consideration to unique aspects at an affected EGU is the interaction between BSER and NSR. EPA is aware that the prospect of triggering NSR, and its associated permitting requirements, may have discouraged sources from implementing some heat rate improvements previously. In Section VIII of this preamble, EPA discusses proposed changes to alleviate NSR burdens for EGUs undertaking heat rate improvements. The proposed action on NSR would ultimately impact the level of reductions reflected in the standard of performance that a state establishes for its sources. In considering each of the candidate technologies, EPA believes it is appropriate for states to consider the potential that the application of HRI may trigger NSR for some sources, and associated NSR requirements could ultimately impact the cost of HRI and the way the state applies standards to an affected EGU. EPA solicits comment on any factors that may play a role in a state setting a standard of performance with consideration to NSR (Comment C–27).

2. Averaging and Trading

EPA solicits comment on the question of whether CAA section 111(d) authorizes states to include averaging and trading between existing sources in the plans they submit to meet the requirements of a final emission guideline (Comment C–28). Section 111(d)(1) provides that states shall submit a plan which (A) establishes standards of performance for any existing source of certain air pollutants to which a 111(b) standard would apply if they were new sources, and (B) provides for the implementation and enforcement of such standards of performance. EPA's regulations under section 111(d) must permit the state, in applying a standard of performance to any particular existing source under a state plan, to consider, among other factors, the remaining useful life of that source.

To be clear, this section discusses averaging in the context of averaging across a facility and across multiple existing sources. For a discussion on EPA allowing individual EGU emissions averaging over a period of time, see Section VI.C.

EPA is proposing to allow states to incorporate, as a part of their plan, emissions averaging among EGUs across a single facility. The Agency's determination of the BSER is predicated on measures that can be implemented at the facility level and averaging across a facility is consistent with the proposed BSER. EPA is proposing that averaging at a facility only be applicable to affected EGUs (*i.e.* coal-fired steam EGUs) for several reasons. First, if averaging could include non-affected EGUs, this might not result in real reductions, but simply result in averaging with lower-emitting emitting fossil-fuel-fired EGUs such as NGCC units that would have been operating anyway. Further, even if it did result in generation shifting to lower emitting units it is contrary to the intention of the rule which is to focus on reducing the rate at coal-fired EGUs when they run, not to reduce the amount they run. Second, EPA is currently considering whether NGCC units should become affected EGUs. How NGCC units fit into an averaging program will be determined if a determination is made that they are affected EGUs in this program. Third, EPA is proposing that facility-wide averaging only apply to affected EGUs because it would mirror the BSER determination for this rule. The EPA solicits comment on whether this type of facility-wide averaging of affected EGUs is appropriate and whether there should be other types of considerations involved (Comment C–29). EPA is also taking comment on the possibility of averaging affected EGUs with non-affected EGUs within a facility in the limited case when they represent incremental new non-emitting capacity (Comment C–30). This would be consistent with a compliance option such as integrated solar.

Notwithstanding EPA's discussion above, EPA believes that there are both legal and practical concerns may weigh against the inclusion of averaging and trading between existing sources in state plans at any level more broad than averaging between sources across a particular facility. First, EPA is concerned that averaging and trading across affected sources (or between affected sources and non-affected sources, *e.g.,* wind turbines) would be inconsistent with our proposed interpretation of the BSER as limited to measures that apply at and to an individual source. Because state plans must establish standards of performance—which by definition ''reflect . . . the application of the [BSER],'' CAA section 111(a)(1)—implementation and enforcement of such standards should correspond with the approach used to set the standard in the first place. Applying a different analytical approach to standard-setting may result in asymmetrical regulation (for example, a state's implementation measures might result in a more stringent standard than could otherwise be derived from application of the BSER).[37]

Second, EPA believes that if section 111(d) authorized states to include trading and averaging between sources in their plans, the express provision under 111(d)(1) authorizing states to consider existing sources' remaining useful life and other factors when establishing and applying standards of performance could be viewed as superfluous. Once a state takes into consideration a source's remaining useful life and other factors (*e.g.,* unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility of installing necessary control equipment; whether the source has already undertaken some of the measures encompassed in the BSER; or other factors), then additional compliance flexibilities may not be required or otherwise appropriate. Indeed, averaging and trading by themselves would appear to eliminate the need to take into consideration a source's remaining useful life: If a source cannot meet a performance standard (or if it is impractical or inadvisable to require that source to do so), but if the state, in its plan, is authorized to permit that

[37] While CAA section 116 allows for states to adopt more stringent state laws, and provides that the CAA does not preempt such state laws, it does not provide that those more stringent standards are federalized.

source to average or otherwise obtain credits for its performance with other sources' performance, there may have been no need for Congress to specifically require EPA to permit states to conduct a remaining-useful-life analysis. Moreover, the source-focused language in 111(d)(1) both generally weighs in favor of EPA's proposed interpretation of the BSER as limited to source-specific measures, and specifically weighs against interpreting section 111(d) to authorize state plans to include averaging and trading.

Third, multiple practical concerns regarding emissions averaging and trading between sources inform EPA's concerns regarding inclusion of those mechanisms in state plans under section 111(d) and its solicitation of comment on this issue. These concerns include the relative complexity of development and implementation of a state plan that includes averaging or trading, as well as the difficulty in ensuring robust compliance with standards of performance by means of averaging or trading. Trading programs necessitate developing adequate means of evaluation, monitoring, and verification (EM&V) to ensure that standards of performance are actually complied with, and these programmatic aspects increase the burden on states in developing a satisfactory state plan, and on sources in demonstrating compliance. Additionally, either a mass-based or rate-based trading program potentially brings into question of whether the state has established standards of performance that appropriately reflect the BSER. Under a trading program, a single source could potentially shut down or reduce utilization to such an extent that its reduced or eliminated operation generates adequate compliance instruments for a state's remaining sources to meet their standards of performance without implementing any additional measures at any other source. This compliance strategy might undermine EPA's BSER, which EPA is proposing to determine as a menu of heat rate improvements. It would also undermine the purpose of section 111 in a broader sense. The section is directed toward the *improvement* of performance of new sources, and, through section 111(d)'s specific procedures, of existing sources. It is *not,* under EPA's proposed interpretation of section 111 (and contrary to the interpretation underlying the CPP), directed toward the aggregate emissions of an industrial sector as a whole, at either the state or national level. Adopting an interpretation of section 111(d) that could lead to relying on the shutdown or reduced operation of one or a small handful of sources in order to cap or limit the source category's aggregate emissions, while not resulting in the improved performance of any other source, may be contrary to the structure and purpose of section 111 as a whole and section 111(d) specifically.

However, EPA recognizes that there are significant benefits of averaging and trading across affected sources and is interested in whether emissions averaging could be a way to provide flexibility while still focusing on a core tenet of the BSER for this rule: Reducing emissions per MWH of coal-fired generation. Since averaging traditionally focuses only on the emission rate during hours of operation, it focuses on encouraging lowering emissions per MW generated and not on encouraging generation shifting away from the affected source category. The EPA welcomes comment on whether there is a way to allow trading between affected EGUs across affected sources while not encouraging generation shifting (Comment C–31).

EPA is soliciting comment on whether section 111(d) should be read not to authorize states to include trading and averaging between sources, EPA is also interested in affording flexibility to states and sources in meeting their respective obligations and solicits public comment on whether this proposed interpretation and conclusion is compatible with that goal. EPA is primarily interested in comments pertaining to whether averaging could and should be allowed for trading, and to what degree (*i.e.,* averaging across a state, or trading) (Comment C–32). If a commenter believes that averaging across multiple affected sources should be allowed as part of a state's plan, EPA requests comment on how the averaging system should conceptually work (Comment C–33). EPA requests comment on how allowing averaging across multiple affected sources would or would not undermine the BSER determination (Comment C–34). If a commenter believes that trading should be allowed as part of a state's plan, EPA requests comment on what type of EM&V criteria should be included for the compliance instruments (Comment C–35). If a commenter believes that trading should be allowed as part of a state's plan, EPA requests comment on whether sources should be allowed to bank compliance instruments (Comment C–36). If a commenter believes that averaging across multiple affected sources should be allowed as part of a state's plan, EPA requests comment on what mechanisms states would need to employ to ensure compliance is maintained and tracked for purposes of providing for the implementation and enforcement of the standards of performance (Comment C–37). If a commenter believes that averaging across multiple affected sources should be allowed as part of a state's plan, EPA requests comment on which and/or if technology should be limited in the averaging program (Comment C–38). If a commenter believes that averaging across multiple affected sources should be allowed as part of a state's plan, EPA requests comment on whether affected EGUs across state lines could be able to average and what measures state plans should include to provide for the implementation and enforcement of such multi-state averaging (Comment C–39). EPA further requests comment on the issues of statutory interpretation laid forth above, whether they are appropriate interpretations of section 111(d) specifically and section 111 generally, in terms of the provision's text, structure, and purpose (Comment C–40). EPA additionally solicits comment on whether such averaging, trading, or ''bubbling'' compliance flexibilities as are available under other sections of title I of the CAA suggest that such flexibilities should be afforded under state plans under section 111(d) (Comment C–41).

C. Submission of State Plans

Section 111(d)(1) of the Clean Air Act requires that in addition to establishing standards of performance for affected sources, such plans must also provide for the implementation and enforcement of such standards. As described in Section VII, EPA is proposing new implementing regulations for section 111(d), which in part carry over a number of the same provisions currently present in the existing implementing regulations under 40 CFR part 60, subpart B. EPA is proposing that these provisions apply for states to meet the requirement that state plans include implementation and enforcement measures. EPA requests comment on whether these provisions are appropriate to apply for purposes of meeting obligations under a final rule in response to this proposal, or whether other implementation or enforcement measures should be required (Comment C–42).

Additionally, EPA is proposing that states must include appropriate monitoring, reporting, and recordkeeping requirements to ensure that state plans adequately provide for the implementation and enforcement of standards of performance. Each state will have the flexibility to design a monitoring program for assessing compliance with the standards of performance identified in the plan. Most potentially affected coal-fired EGUs already continuously monitor CO_2 emissions, heat input, and gross electric output and report hourly data to EPA under 40 CFR part 75. Accordingly, if a state plan establishes a standard of performance for a unit's CO_2 emissions rate (*e.g.,* lb/MWh), EPA proposes that states may elect to use data collected by EPA under 40 CFR part 75 to meet the required monitoring, reporting, and recordkeeping requirements under this emission guideline.

EPA also notes that states have it within their discretion to establish averaging times for affected EGUs. Averaging the emission rate of an affected EGU over different time periods may have different effects on the demonstration of compliance for an EGU to the state. EPA solicits comment on whether there should be any bounds or consideration to the averaging times that states are allowed to consider (Comment C–43).

EPA is further proposing to apply generally the proposed new implementing regulations for timing, process and required components for state plan submissions and implementation for state plans required under for affected EGUs. The new implementing regulations are described in detail in Section VII. In addition to application of the implementing regulations to state plans in response to a final emission guideline under this proposal, EPA is also proposing that state plans be comprehensively submitted electronically through an EPA provided platform. EPA solicits comment on whether electronic submittals are appropriate and less burdensome to states (Comment C–44) and whether this should be the sole means of submitting state plans (Comment C–45). EPA believes that electronic submittals will ease the burden of state plan submittals for both states and EPA.

In section 60.5740a of the regulatory text for this proposal, there is description and list of what a state plan must include. EPA solicits comment on whether this list is comprehensive to submit a state plan (Comment C–46).

VII. Proposed New Implementing Regulations for Section 111(d) Emission Guidelines

Distinct from EPA's proposed emission guidelines for the regulation of GHGs for existing affected EGUs, EPA is also proposing to promulgate new regulations to implement section 111(d) regulations. As previously described, the current implementing regulations at 40 CFR part 60, subpart B were promulgated in 1975 [*See* 40 FR 53346.]. Section 111(d)(1) of the CAA explicitly requires that EPA establish regulations similar to those under section 110 of the CAA to establish a procedure for states to submit plans to EPA. The implementing regulations have not been significantly revised since their original promulgation in 1975. Notably, the implementing regulations do not reflect section 111(d) in its current form as amended by Congress in 1977, and do not reflect section 110 in its current form as amended by Congress in 1990. Accordingly, EPA believes that certain portions of the implementing regulations do not appropriately align with section 111(d), contrary to that provision's mandate that EPA's regulations be ''similar'' to the provisions under section 110. Therefore, EPA is proposing to promulgate new implementing regulations that are in accordance with the statute in its current form. As previously discussed, agencies have the ability to revisit prior decisions, and EPA believes it is appropriate to do so here in light of the potential mismatch between certain provisions of the implementing regulations and the statute.[38]

EPA is proposing to largely carry over the current implementing regulations in 40 CFR part 60, subpart B to a new subpart that will be applicable to EPA's emission guidelines and state plans or federal plans associated with such emission guidelines, both those contemplated in this proposal and for any others that may be published or promulgated either concurrently or subsequent to final promulgation of the new implementing regulations. For purposes of regulatory certainty, EPA believes it is appropriate to apply these new implementing regulations prospectively, and retain the existing implementing regulations as applicable to section 111(d) emission guidelines and associated state plans that were promulgated previously. Additionally, the existing implementing regulations at 40 CFR part 60, subpart B are applicable to regulations promulgated under CAA section 129, and associated state plans. EPA intends to retain the applicability of the existing implementing regulations with respect to rules and state plans associated with section 129, and the proposed new implementing regulations are intended to apply only to section 111(d) regulations and associated state plans issued solely under the authority of section 111(d). EPA requests comments on this proposed applicability of both the existing and new implementing regulations (Comment C–47).

EPA is aware that there are a number of cases where state plan submittal and review processes are still ongoing for existing 111(d) emission guidelines. Because EPA is proposing changes to the timing requirements to more closely align 111(d) with both general SIP submittal timing requirements and because of the realities of how long these actions take, EPA is proposing to apply the changes to timing requirements to both emission guidelines published after the new implementing regulations are finalized, and to all ongoing emission guidelines already published under section 111(d). EPA is soliciting comment on the proposed timing requirements for prospective emission guidelines under the new implementing regulations and the alignment of ongoing emission guidelines by amending their respective regulatory text to incorporate the new timing requirements. (Comment C–48). EPA is proposing to apply the timing changes to all ongoing 111(d) regulations for the same reasons that EPA is changing the timing requirements prospectively. Based on years of experience with working with states to develop SIPs under section 110, EPA believes that given the comparable amount of work, effort, coordination with sources, and the time required to develop state plans that more time is necessary for the process. Giving states three years to develop state plans is more appropriate than the nine months provided for under the existing implementing regulations considering the workload. These practical considerations regarding the time needed for state plan development are also applicable and true for recent emission guidelines where the state plan submittal and review process are still ongoing.

For those provisions that are being carried over from the existing implementing regulations into the new implementing regulations, EPA believes the placement of those provisions under a new subpart is a ministerial action that does not require reopening the substance of those provisions for notice and comment. EPA is not intending to substantively change those provisions from their original promulgation, and continues to rely on the record under

[38] The authority to reconsider prior decisions exists in part because EPA's interpretations of statutes it administers ''[are not] instantly carved in stone,'' but must be evaluated ''on a continuing basis.'' *Chevron U.S.A. Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 863–64 (1984). Indeed, ''[a]gencies obviously have broad discretion to reconsider a regulation at any time.'' *Clean Air Council* v. *Pruitt,* 862 F.3d 1, 8–9 (DC Cir. 2017).

which they were promulgated. Therefore, EPA is not soliciting comment on the following provisions, which remain substantively the same from their original promulgation: 40 CFR 60.21a(a)–(d), (g)–(j) (Definitions); 60.22a(a), 60.22a(b)(1)–(3), (b)(5), (c) (Publication of emission guidelines); 60.23a(a)–(c), (d)(3)–(5), (e)–(h) (Adoption and submittal of State plans; public hearings); 60.24a(a)–(d), (f) (Standards of performance and compliance schedules); 60.25a (Emission inventories, source surveillance, reports); 60.26a (Legal authority); 60.27a(a), (e)–(f) (Actions by the Administrator); 60.28a(b) (Plan revisions by the State); 60.29a (Plan revisions by the Administrator).

EPA is also sensitive to potential confusion over whether these new implementing regulations would apply to an emission guideline previously promulgated or to state plans associated with a prior emission guideline, so EPA is proposing that the new implementing regulations are applicable only to emission guidelines and associated plans developed after promulgation of this regulation, including the emission guideline being proposed as part of this action for GHGs and existing affected EGUs. EPA solicits comment on this proposed applicability of the new implementing regulations (Comment C–49).

While EPA is carrying over a number of requirements from the existing implementing regulations, EPA is proposing specific changes to better align the regulations with the statute. These changes are reflected in the proposed regulatory text for this action, and EPA solicits comments on both the substance of these changes and the proposed regulatory text (Comment C–50). These changes include:

- An explicit provision allowing a specific emission guideline to supersede the requirements of the new implementing regulations;
- Changes to the definition of ''emission guideline'';
- Updated timing requirements for the submission of state plans;
- Updated timing requirements for EPA's action on state plans;
- Updated timing requirements for EPA's promulgation of a federal plan;
- Updated timing requirement for when increments of progress must be included as part of a state plan;
- Completeness criteria and a process for determining completeness of state plan submissions similar to CAA section 110(k)(1) and (2);
- Updated definition replacing ''emission standard'' with ''standard of performance;''
- Usage of the internet to satisfy certain public hearing requirements;
- No longer making a distinction between public health-based and welfare-based pollutants in an emission guideline; and,
- Updating the variance provision to be consistent with CAA section 111(d)(1)(B).

EPA is proposing to include a provision in the new implementing regulations that expressly allows for any emission guideline to supersede the applicability of the implementing regulations as appropriate. EPA cannot foresee all of the unique circumstances and factors associated with a particular future emission guideline, and therefore different requirements may be necessary for a particular 111(d) rulemaking that EPA cannot envision at this time. The proposed provision is parallel to one contained in the 40 CFR part 63 General Provisions implementing section 112 of the CAA. EPA solicits comments on the inclusion of such provision as part of the implementing regulations for section 111(d) (Comment C–51).

Because EPA is updating the implementing regulations and many of the provisions from the existing implementing regulations are being carried over, EPA wants to be clear and transparent with regard to the changes that are being made to the implementing regulations. As such, EPA is providing Table 4 that summarizes the changes being made. EPA also has included in the docket for this action a red-line-strike-out of the changes that are being proposed.

TABLE 4—SUMMARY OF CHANGES TO THE IMPLEMENTING REGULATIONS

New implementing regulations—subpart Ba for all future 111(d) emission guidelines	Existing implementing regulations—subpart B for all previously promulgated 111(d) emission guidelines
Explicit authority for a new 111(d) emission guideline requirement to supersede these implementing regulations.	No explicit authority.
Use of term ''guideline document''; does not require EPA to provide a presumptive emission standard.	Use of term ''emission guideline''; arguably required EPA to provide a presumptive emission standard.
Use of term ''standard of performance''	Use of term ''emission standard''.
''Standard of performance'' allows states to include design, equipment, work practice, or operational standards when EPA determines it's not feasible to prescribe or enforce a standard pf performance, consistent with the requirements of CAA section 111(h).	''Emission standard'' allows states to prescribe equipment specifications when EPA determines it's clearly impracticable to establish an emission standard.
State submission timing: 3 years from promulgation of a final emission guideline.	State submission timing: 9 months from promulgation of a final emission guideline.
EPA action on state plan submission timing: 12 months after determination of completeness.	EPA action on state plan submission timing: 4 months after submittal deadline.
Timing for EPA promulgation of a federal plan, as appropriate: 2 years after finding of failure to submit a complete plan, or disapproval of state plan.	Timing for EPA promulgation of a federal plan, as appropriate: 6 months after submittal deadline.
Increments of progress are required if compliance schedule for a state plan is longer than 24 months after the plan is due.	Increments of progress are required if compliance schedule for a state plan is longer than 12 months after the plan is due.
Completeness criteria and process for state plan submittals	No previous discussion.
Usage of the internet to satisfy certain public hearing requirements	No previous discussion.
No distinction made in treatment between health-based and welfare-based pollutants; variance provision available regardless of type of pollutant.	Different provisions for health-based and welfare-based pollutants; state plans must be as stringent as EPA's emission guideline for health-based pollutants unless variance provision is invoked.

A. Changes to the Definition of ''Emission Guideline''

The existing implementation regulations under 40 CFR 60.21(e) contain a definition of ''emission guideline'', defining it as a guideline which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities. This definition additionally references that an emission guideline may be set forth in 40 CFR part 60, subpart C or a ''final guideline document'' published under 40 CFR 60.22(a). While the implementing regulations do not define the term ''final guideline document,'' 40 CFR 60.22 generally contains a number of requirements pertaining to the contents of guideline documents, which are intended to provide information for the development of state plans. *See* 40 CFR 60.22(b). The preambles for both the proposed and final existing implementing regulations suggest that an ''emission guideline'' would be a guideline provided by EPA that presumptively reflects the degree of emission limitation achievable by the BSER. EPA believes it is important to at least provide information on such degree of emission limitation in order to guide states in their establishment of standards of performance as required under CAA section 111(d). However, EPA does not believe anything in CAA section 111(a)(1) or section 111(d) compels EPA to provide a presumptive emission standard that reflects the degree of emission limitation achievable by application of the BSER. Accordingly, as part of the new implementing regulations, EPA proposes to re-define ''emission guideline'' as a final guideline document published under § 60.22a(a), which includes information on the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction and any nonair quality health and environmental impact and energy requirements) EPA has determined has been adequately demonstrated for designated facilities.

B. Updates to Timing Requirements

The timing requirements in the existing implementing regulations for state plan submissions, EPA's action on state plan submissions and EPA's promulgation of federal plans generally track the timing requirements for SIPs and federal implementation plans (FIPs) under the 1970 version of the Clean Air Act. Congress revised these SIP/FIP timing requirements in section 110 as part of the 1990 Clean Air Act amendments. EPA proposes to accordingly update the timing requirements regarding state and federal plans under section 111(d) to be consistent with the current timing requirements for SIPs and FIPs under section 110. The existing implementing regulations at 40 CFR 60.23(a)(1) requires state plans to be submitted to EPA within nine months after publication of a final emission guideline, unless otherwise specified in an emission guideline. EPA is proposing, as part of new implementing regulations, to provide states with three years after the notice of the availability of the final emission guideline to adopt and submit a state plan to EPA. Because of the amount of work, effort, and time required for developing state plans that include unit-specific standards, and implementation and enforcement measures for such standards, EPA believes that extending the submission date of state plans from nine months to three years is appropriate. Because states have considerable flexibility in implementing section 111(d), this timing also allows states to interact and work with the Agency in the development of state plan and minimize the chances of unexpected issues arising that could slow down eventual approval of state plans. EPA solicits comment on generally providing states with three years after the publication of the final emission guidelines, and solicits comment on any other timeframes that may be appropriate for submission of state plans given the flexibilities EPA intends to provide through its emission guidelines (Comment C–52). EPA also proposes to give itself discretion to determine in a specific emission guideline that a shorter time period for the submission of state plans particular to that emission guideline is appropriate. Such authority is consistent with CAA section 110(a)(1)'s grant of authority to the Administrator to determine that a period shorter than three years is appropriate for the submission of particular SIPs implementing the NAAQS.

Following submission of state plans, EPA will review plan submittals to determine whether they are ''satisfactory'' as per CAA section 111(d)(2)(A). Given the flexibilities section 111(d) and emission guidelines generally accord to states, and EPA's prior experience on reviewing and acting on SIPs under section 110, EPA is proposing to extend the period for EPA review and approval or disapproval of plans from the four-month period provided in EPA implementing regulations to a twelve-month period after a determination of completeness (either affirmatively by EPA or by operation of law, see below for EPA's proposal on completeness) as part of the new implanting regulations. This timeline will provide adequate time for EPA to review plans and follow notice-and-comment rulemaking procedures to ensure an opportunity for public comment on EPA's proposed action on a state plan. EPA solicits comment on extending the timing of EPA's action on a state plan from 4 months of when a plan is due to 12 months from determination that a state plan submission is complete (Comment C–53).

EPA additionally proposes to extend the timing from six months in the existing implementing regulations to two years, as part of new implementing regulations, for EPA to promulgate a federal plan for states that fail to submit an approvable state plan in response to a final emission guideline. This two-year timeline is consistent with the FIP deadline under section 110(c) of the CAA. EPA solicits comment on change in timing for EPA to promulgate a federal plan from six months to two years (Comment C–54). EPA solicits comment on extending deadline for promulgating a final (*i.e.,* after appropriate notice and comment) federal plan for a state to two years after either (1) EPA finds that a state has failed to submit a complete plan, or (2) EPA disapproves a state plan submission (Comment C–55).

C. Compliance Deadlines

The existing implementing regulations require that any compliance schedule for state plans extending more than 12 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. 40 CFR 60.24(e)(1). However, as described in section VII.B, the EPA is proposing certain updates to the timing requirements for the submission of, and action on, state plans. Consequently, it follows that the requirement for increments of progress should also be updated in order to align with the proposed new timelines. Given that the EPA is proposing a period of up to 18 months for its action on state plans (*i.e.* 12 months from the determination that a state plan submission is complete, which could occur up to six months after receipt of the state plan), EPA believes it is appropriate that the requirement for increments of progress should attach to plans that contain compliance periods that are longer than the period provided for EPA's review of such plans. This way, sources subject to a plan have more certainty that their regulatory compliance obligations would not change between the period between when a state plan is due and when EPA acts on a plan. Accordingly, EPA proposes that increments of progress will be included for state plans that contain compliance schedules longer than 24 months from the date when state plans are due for a particular emission guideline. EPA solicits comments on whether this 24-month component, or some other period of time, is appropriate as a trigger for requiring increments of progress as part of a plan's compliance schedule.

D. Completeness Criteria

Similar to requirements regarding determinations of completeness under section 110(k)(1), EPA is proposing completeness criteria that provide the Agency with a means to determine whether a state plan submission includes the minimum elements necessary for EPA to act on the submission. EPA would determine completeness simply by comparing the state's submission against these completeness criteria. In the case of SIPs under CAA section 110(k)(1), EPA promulgated completeness criteria in 1990 at Appendix V to 40 CFR part 51 (55 FR 5830; February 16, 1990). EPA proposes to adopt criteria similar to the criteria set out at section 2.0 of Appendix V for determining the completeness of submissions under CAA section 111(d).

EPA notes that the addition of completeness criteria in the framework regulations does not alter any of the submission requirements states already have under any applicable emission guideline. The completeness criteria proposed by this action are those that would generally apply to all plan submissions under section 111(d), but specific emission guidelines may supplement these general criteria with additional requirements.

The completeness criteria that EPA is proposing in this action can be grouped into administrative materials and technical support. For administrative materials, the completeness criteria mirror criteria for SIP submissions because the two programs have similar administrative processes. Under these criteria, the submittal must include the following:

(1) A formal letter of submittal from the Governor or the Governor's designee requesting EPA approval of the plan or revision thereof.

(2) Evidence that the state has adopted the plan in the state code or body of regulations. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date.

(3) Evidence that the state has the necessary legal authority under state law to adopt and implement the plan.

(4) A copy of the official state regulation(s) or document(s) submitted for approval and incorporated by reference into the plan, signed, stamped and dated by the appropriate state official indicating that they are fully adopted and enforceable by the state. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submission must indicate the changes made to the approved plan by redline/strikethrough.

(5) Evidence that the state followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption/issuance of the plan.

(6) Evidence that public notice was given of the plan or plan revisions with procedures consistent with the requirements of 40 CFR 60.23, including the date of publication of such notice.

(7) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23.

(8) Compilation of public comments and the state's response thereto.

The technical support required for all plans must include each of the following:

(1) Description of the plan approach and geographic scope.

(2) Identification of each designated facility; identification of emission standards for each designated facility; and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility.

(3) Identification of compliance schedules and/or increments of progress.

(4) Demonstration that the state plan submission is projected to achieve emissions performance under the applicable emission guidelines.

(5) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole.

(6) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

EPA intends that these criteria be generally applicable to all CAA section 111(d) plans submitted on or after final new implementing regulations are promulgated, with the proviso that specific emission guidelines may provide otherwise.

Consistent with the requirements of CAA section 110(k)(1)(B) for SIPs, EPA is proposing to determine whether a state plan is complete (*i.e.,* meets the completeness criteria) no later than 6 months after the date, if any, by which a state is required to submit the plan. EPA further proposes that any plan or plan revision that a State submits to EPA, and that has not been determined by EPA by the date 6 months after receipt of the submission to have failed to meet the minimum completeness criteria, shall on that date be deemed by operation of law to be a complete state plan. Then, as previously discussed, EPA is relatedly proposing to act on a state plan submission within 12 months after determining a plan is complete, either through an affirmative determination or by operation of law.

When plan submissions do not contain the minimum elements, EPA is proposing to find that a state has failed to submit a complete plan through the same process as finding a state has made no submission at all. Specifically, EPA would notify the state that its submission is incomplete and therefore, that it has not submitted a required plan, and EPA would also publish a finding of failure to submit in the **Federal Register**, which triggers EPA's obligation to promulgate a federal plan for the state. This determination that a submission is incomplete and the state has failed to submit a plan is ministerial in nature and requires no exercise of discretion or judgment on the Agency's part, nor does it reflect a judgment on the eventual approvability of the submitted portions of the plan.

E. Standard of Performance

As previously described, the implementing regulations were promulgated in 1975 and effectuated the 1970 version of the Clean Air Act as at it existed at that time. The 1970 version of section 111(d) required state plans to include ''emission standards'' for existing sources, and consequently the implementing regulations refer to this term. However, as part of the 1977 amendments to the CAA, Congress replaced the term ''emission standard'' in section 111(d) with ''standard of performance.'' EPA has not since revised the implementing regulations to reflect this change in terminology. For clarity's sake and to better track with statutory requirements, EPA is proposing to include a definition of ''standards of performance'' as part of the new implementing regulations, and to consistently refer to this term as appropriate within those regulations in lieu of referring to an ''emission standard.'' Additionally, the current definition of ''emission standard'' in the implementing regulations is incomplete and requires clean-up regardless. For example, the definition encompasses equipment standards, which is an alternative form of standard provided for in CAA section 111(h) under certain circumstances. However, section 111(h) provides for other forms of alternative standards, such as work practice standards, which are not covered by the existing regulatory definition of ''emission standard.'' Furthermore, the definition of ''emission standard'' encompasses allowance systems, a reference that was added as part of EPA's Clean Air Mercury Rule. 70 FR 28605. This rule was vacated by the D.C. Circuit, and therefore this added component to the definition of ''emission standard'' had no legal effect because of the court's vacatur. Consistent with the court's opinion, EPA signaled its intent to remove this reference as part of its Mercury Air Toxics rule. 77 FR 9304. However, in the final regulatory text of that rulemaking, EPA did not take action removing this reference, and it remains as a vestigial artifact.

For these reasons, EPA is proposing to replace the existing definition of ''emission standard'' with a definition of ''standard of performance'' that tracks with the definition provided for under CAA section 111(a)(1). This means a standard of performance for existing sources would be defined as a standard for emissions or air pollutants which reflects the degree of emission limitation achievable through the application by the state of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. EPA is further proposing to incorporate into a definition of standard of performance CAA section 111(h)'s allowance for design, equipment, work practice, or operational standards as alternative standards of performance under the statutorily prescribed circumstances. Currently, the existing implanting regulations allow for state plans to prescribe equipment specifications when emission rates are ''clearly impracticable'' as determined by EPA. CAA section 111(h)(1) by contrast allows for alternative standards such as equipment standards to be promulgated when standards of performance are ''not feasible to prescribe or enforce,'' as those terms are defined under CAA section 111(h)(2). Given the potential discrepancy between the conditions under which alternative standards may be established based on the different terminology used by the statute and existing implementing regulations, EPA proposes to use the ''not feasible to prescribe or enforce'' language as the condition for the new implementing regulations under which alternative standards may be established.

EPA solicits comment on all of these means of tracking and incorporating the section 111(a)(1) and 111(h) for purposes of a regulatory definition of ''standard of performance,'' and requests comment on any other considerations for such definition (Comment C–56).

F. Variance

EPA believes that the existing implementing regulations' distinction between public health-based and welfare-based pollutants is not a distinction unambiguously required under section 111(d) or any other applicable provision of the statute. EPA does not believe the nature of the pollutant in terms of its impacts on health and/or welfare impact the manner in which it is regulated under this provision. Particularly, 60.24(c) requires that for health-based pollutants, a state's standards of performance must be of equivalent stringency to EPA's emission guidelines. However, section 111(d)(1)(B) requires that EPA's regulations must permit states to take into account, among other factors, an affected source's remaining useful life when establishing an appropriate standard of performance. In other words, Congress explicitly envisioned under section 111(d)(1)(B) that states could implement standards of performance that vary from EPA's emission guidelines under appropriate circumstances. Notably, the implementing regulations at 40 CFR 60.24(f) contain a variance provision that allow for states to also apply less stringent standards on sources under certain circumstances. However, the variance provision attaches to the distinction between health-based and welfare-based pollutants, and is available to the states only under EPA's discretion. The variance provision was also promulgated prior to Congress's addition of the requirement in section 111(d)(1)(B) that EPA permit states to take into account remaining useful life and other factors, and the terms of the regulatory provision and statutory provision do not match one another, meaning that the variance provision may not account for all of the factors envisioned under section 111(d)(1)(B). Given all of these factors, EPA is proposing to not make a distinction between health-based and welfare-based pollutants and attach requirements contingent upon this distinction as part of the new implementing regulations. EPA is also proposing a new variance provision to permit states to take into account remaining useful life, among other factors, in establishing a standard of performance for a particular affected source, consistent with section 111(d)(1)(B).

Given that there are unique attributes and aspects of each affected source, these other factors may be ones that influence decisions to invest in technologies to meet a potential performance standard. Such other factors may include timing considerations like expected life of the source, payback period for investments, the timing of regulatory requirements, and other unit-specific criteria. EPA solicits comments on how a new variance provision can permit states to take into account remaining useful life and other factors, and what other factors might appropriately be (Comment C–57). EPA is also soliciting comment on whether the factors outlined in the existing variance provision at 40 CFR 60.24(f) are appropriate to carry over to a new variance provision if they adequately give meaning to the requirements of section 111(d)(1)(B) (Comment C–58). Those factors are:

- Unreasonable cost of control resulting from plant age, location, or basic process design;
- Physical impossibility of installing necessary control equipment; or
- Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

VIII. New Source Review Permitting of HRIs

A. What is New Source Review?

The NSR program is a preconstruction permitting program that requires stationary sources of air pollution to obtain permits prior to beginning construction. The NSR program applies both to new construction and to modifications of existing sources. New construction and modifications of stationary sources that emit or increase emissions of ''regulated NSR pollutants'' [39] at or above certain thresholds defined in either the CAA or the NSR regulations are subject to major NSR requirements, while smaller emitting sources and modifications may be subject to minor NSR requirements.[40] A pollutant is a ''regulated NSR pollutant'' if it meets at least one of four requirements, which are, in general, any pollutant for which EPA has promulgated a NAAQS or a NSPS, certain ozone depleting substances, and ''[a]ny pollutant that otherwise is subject to regulation under the Act.'' *See, e.g.,* 40 CFR 52.21(b)(50). For purposes of NSR, hazardous air pollutants are excluded. *Id.*

NSR permits for major sources emitting pollutants for which the area is classified as attainment or unclassifiable, and for other pollutants regulated under the CAA, are referred to as prevention of significant deterioration (PSD) permits. NSR permits for major sources emitting pollutants for which the area is in nonattainment are referred to as nonattainment NSR (NNSR) permits. The pollutant(s) at issue and the air quality designation of the area where the facility is located or proposed to be built determine the specific permitting requirements.[41] Among other requirements, the CAA requires sources subject to PSD to meet emission limits based on Best Available Control Technology (BACT) as specified by section 165(a)(4), and the CAA requires sources subject to NNSR to meet the Lowest Achievable Emissions Rate (LAER) pursuant to section 173(a)(2). These technology requirements for major NSR permits are not predetermined by a rule or state plan, but are case-by-case determinations made by the permitting authority.[42] Other requirements to obtain a major NSR permit vary depending on whether the source needs a PSD or an NNSR permit.

The test to determine whether a source is subject to major NSR differs for new stationary sources and for modifications to existing stationary sources. A new source is subject to major NSR permitting requirements if its potential to emit (PTE) any regulated NSR pollutant equals or exceeds the statutory emission threshold. For sources in attainment areas, the major source threshold is either 100 or 250 tons per year, depending on the type of source.[43] The major source threshold for sources in nonattainment areas is generally 100 tons per year, although lower thresholds apply to sources located in areas classified at higher levels of nonattainment.

A modification at an existing major source is subject to major NSR permitting requirements when it is a ''major modification,'' which occurs when a source undertakes a physical change or change in method of operation (*i.e.,* a ''project'') [44] that would result in both (1) a significant emissions increase from all emission units that are part of the project, and (2) a significant net emissions increase from the source, which is determined by a source-wide analysis that considers creditable emission increases and decreases occurring at the source as a result of other projects over a 5-year contemporaneous period. *See, e.g.,* 40 CFR 52.21(b)(2)(i). For this analysis, the NSR regulations define emissions rates that are ''significant'' for each NSR pollutant. *See, e.g.,* 40 CFR 52.21(b)(23). In calculating the emissions increase that will result from a proposed project, existing NSR regulations require a comparison of the ''projected actual emissions'' (PAE) to the ''baseline actual emissions'' (BAE). The PAE is currently defined as the maximum *annual* rate that the modified unit is projected to emit a pollutant in any one of the 5 years (or 10 years if the design capacity increases) after the project, excluding any increase in emissions that (1) is unrelated to the project, and (2) could have been accommodated during the baseline period (commonly referred to as the ''demand growth exclusion''). *See, e.g.,* 40 CFR 52.21(b)(41). For electric utility steam generating units (EUSGU), the BAE is defined as the average *annual* rate of actual emissions during any 24-month period within the last 5 years. *See, e.g.,* 40 CFR 52.21(b)(48)(i). For non-EUSGUs, the BAE is defined the same as for EUSGUs, except that the 24-month period can be within the last 10 years. *See, e.g.,* 40 CFR 52.21(b)(48)(ii).[45]

As noted above, new stationary sources and modifications of stationary sources that do not require a major NSR permit may instead require a minor NSR permit prior to construction. Minor NSR permits are primarily issued by state and local air agencies. Minor NSR requirements are approved into an implementation plan in order to achieve and maintain national ambient air quality standards (NAAQS). *See* CAA section 110(a)(2)(C).[46] The Act, EPA regulations and EPA guidance each specify minor NSR requirements, although the requirements are not as prescriptive as those covering the major NSR program. This reduced specificity affords agencies flexibility in designing their minor NSR programs. Since the minor NSR program deals with smaller sources and smaller increases in air pollution, the control requirements that are identified for a minor NSR permit tend to be less stringent than a BACT or LAER requirement for a major NSR permit. In addition, the time to process a permit for a minor NSR source or a minor modification is generally faster than for a major NSR permit, due to having fewer requirements.

B. Interaction of NSR and the ACE Rule

Since emission guidelines that are established pursuant to CAA section 111(d) apply to units at existing sources, the way in which the NSR programs treat modifications of existing sources is implicated by implementation of a CAA section 111(d) program. Specifically, in complying with the emission guidelines, a state agency may develop

[39] 40 CFR 51.165(a)(1)(xxxvii), 40 CFR 52.21(b)(50).

[40] The one exception to this approach is for GHG. Regardless of the GHG emissions resulting from construction of a new source or modification, the source will not be required to obtain a major NSR permit unless the emissions of another regulated NSR pollutant equal or exceed the major NSR threshold. 80 FR 50199 (August 19, 2015); *Utility Air Regulatory Group* v. *EPA,* 134 S. Ct. 2427 (2015).

[41] PSD applies on a regulated NSR pollutant-by-regulated NSR pollutant basis. The PSD requirements do not apply to regulated NSR pollutants for which the area is designated as nonattainment. NNSR could only be applicable with regard to a source's emissions of criteria pollutants, as those are the only pollutants with respect to which areas are designated as attainment or nonattainment.

[42] The term 'best available control technology' means an emission limitation . . . which the permitting authority, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility . . .'' 42 U.S.C. 7479(3); *see e.g., supra* Section III.C; PSD and Title V Permitting Guidance for Greenhouse Gases (Mar. 2011), available at *https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf.*

[43] The NSR major source and major modification emission thresholds are expressed in short tons (*i.e.,* 2000 lbs.).

[44] The NSR regulations expressly exempt certain activities from being considered a physical change or change in method of operation, including routine maintenance, repair and replacement, increases in hours of operation or production rate, and change in ownership. *See, e.g.,* 40 CFR 52.21(b)(2)(iii).

[45] While we are discussing federal regulations, a state or local permitting authority may have different regulations to define NSR applicability if approved by EPA into its implementation plan.

[46] EPA's regulations at 40 CFR 51.160–51.169 apply to state permitting programs; however, these provisions cover both major and minor sources. The requirements that apply to strictly minor sources are limited to sections 51.160–51.164. In addition, in 2011 EPA created the Indian country minor NSR permitting program, which authorizes EPA regional offices to issue minor source permits on tribal lands. These regulations are located at 40 CFR 49.101–49.104 and 49.151–49.164.

a CAA section 111(d) plan that results in an affected source undertaking a physical or operational change. As explained above, under the NSR program undertaking a physical or operational change may require that the source obtain a preconstruction permit for the proposed change, with the type of NSR permit depending on the amount of the emissions increase resulting from the change and the air quality at the location of the source. Thus, a source that is adding equipment or otherwise making changes to its facility, on either its own volition or to comply with a national or state level requirement, will typically need some type of NSR permit prior to making such changes to its facility. EPA sought to exempt environmentally beneficially pollution control projects from NSR requirements in a 2002 rule that codified longstanding EPA policy, but this rule was struck down in court. *New York* v. *EPA,* 413 F.3d 3, 40–42 (DC Cir. 2005) (*New York I*).

With respect to the proposed action, should it be promulgated, states will be called upon to develop a section 111(d) plan that evaluates BSER technologies for each of their EGU sources and assigns emission reduction compliance obligations to their affected EGUs. Assuming the promulgated action adopts the same form as this proposal, the state may require a source with an affected EGU to achieve a HRI of a specified percentage. As described in Section VI.B of this preamble, a HRI project is designed to lower the heat rate of the EGU, which correlates to the unit consuming less fuel per kWh and emitting lower amounts of CO_2 (and other air pollutants) per kWh generated as compared to a less efficient unit. Along with this increase in energy efficiency, the EGU which undergoes the HRI project will typically experience greater unit availability and reliability, all of which contribute to lower operating costs. EGUs that operate at lower costs are generally preferred in the dispatch order by the system operator over units that have higher operational costs,[47] and EPA's regulatory impact analysis (RIA) for this action (located in the docket) shows that improving an EGU's heat rate will lead to increased generation due to its improved efficiency and relative economics. As the EGU increases its generation, to the extent the EGU operates beyond its historical levels by a meaningful amount, it could result in an increase in emissions on an annual basis, as calculated pursuant to the current NSR regulations. Specifically, if a source is undertaking a HRI project and its future emissions (*i.e.,* PAE) are projected to increase above its historical emissions (*i.e.,* BAE) in an amount greater than the relevant ''significant'' level, the source could be required to obtain a major NSR permit for the modification.

Thus, it is possible that a source undertaking a HRI project at its EGU would project, or actually experience, an increase in operation of its EGU and a corresponding increase in annual emissions. This would require the source, at a minimum, to conduct an analysis to determine whether the project by itself is projected to lead to a significant emissions increase (at step one of the two-step analysis that determines whether a project constitutes a ''major modification''). If so, the source would have to conduct a netting analysis to determine whether there is also a significant net increase when contemporaneous increases and decreases from other projects are considered (step two of that analysis). If both of these types of increases would be projected to occur, this could result in the source being subject to additional pollutant control requirements (*e.g.,* BACT or LAER), in addition to the substantial extra time and cost of applying for a major NSR permit prior to undertaking the HRI project. Such could be the consequence despite the fact that the project would lower the EGU's output-based emissions rate for its air pollutants, and despite the fact that the resulting effect on the dispatch order could yield an emission reduction from a system-wide standpoint.

Similarly, over the years, some stakeholders have asserted that the NSR rules discourage companies from exercising the discretion to undertake energy efficiency improvement projects, which they assert results in less environmentally protective outcomes from a system-wide standpoint. Stakeholders have claimed that triggering major NSR permitting requirements can increase the costs of beneficial plant improvement projects, like HRIs, and often contribute to a company's decision to forego the projects. For instance, a commenter on the CPP proposal stated that ''many coal-fired plants may refrain from making improvements based on the financial risk associated with potentially triggering a New Source Review, which may result in the requirement to invest in additional emissions controls . . . . [T]he [permitting] requirements could increase costs of potential heat rate improvements and therefore are a potential impediment which should be recognized in the rule's calculations.'' [48]

In promulgating the CPP, EPA noted that these stakeholders expressed concerns of the potential NSR permitting effects from a state implementing the rule, stating ''[w]hile there may be instances in which an NSR permit would be required, we expect those situations to be few . . . states have considerable flexibility in selecting varied measures as they develop their plans to meet the goals of the emission guidelines. One of these flexibilities is the ability of the state to establish emission standards in their CAA section 111(d) plans in such a way so that their affected sources, in complying with those standards, in fact would not have emissions increases that trigger NSR. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the emission standards in their CAA section 111(d) plan, the source's emissions would not increase in a way that trigger NSR requirements.'' 80 FR 64920 (October 23, 2015). The CPP also explained that sources can voluntarily take enforceable limits on hours of operation, in the form of a synthetic minor source limitation, in order to avoid triggering major NSR requirements that would otherwise apply to the source. 80 FR 64781, 64920.

However, these concerns regarding the applicability of NSR take on even greater significance and may not be as easily avoided in the context of this proposed rule, which constrains the compliance options available in the CPP to within-the-fenceline measures and may therefore more directly result in individual sources making HRIs.

Individuals within the academic community have examined the NSR interplay with making efficiency gains at existing coal plants. A 2014 report projected that 80 percent of non-retiring coal-fired units have emissions rates for NO_X and SO_2 at levels that exceed those typically required under NSR and concluded that the units would have to install additional controls for NO_X or sulfur dioxide (SO_2) if these HRI projects triggered the applicability of

[47] *See, e.g.,* Comments of Florida Municipal Elec Association on the U.S. Environmental Protection Agency's ANPRM entitled, ''State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,'' 82 FR 61507 (December 28, 2017) at 11 (EPA–HQ–OAR–2017–0545–0155); *see also https://www.eia.gov/todayinenergy/detail.php?id=7590.*

[48] Electric Power Research Institute comments U.S. Environmental Protection Agency's Proposed Rule ''Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units,'' 79 FR 34830 (June 18, 2014) at 12–13 (EPA–HQ–OAR–2013–0602–21697).

NSR.[49] For these units then, the potential requirement to undertake a HRI to satisfy 111(d) may result in substantial time, effort, and money to comply with the requirements of major NSR. In addition, the potential need to permit so many of the projects being required under a 111(d) plan could substantially increase the burden for permit agencies in processing permit applications. To help reduce the effect this may have on the effective and prompt implementation of a revised CAA section 111(d) standard for EGUs, EPA is proposing revisions to the NSR regulations in this action.

C. ANPRM Solicitation and Comments Received

Through the ANPRM, EPA took comment on the topic of how the NSR program overlays with emission guidelines established under CAA section 111(d). EPA specifically acknowledged the concerns raised previously by stakeholders regarding the potential for a source to make energy efficient improvements that could trigger major NSR requirements. Furthermore, as EPA did in the CPP, EPA described current approaches available within the NSR program to avoid triggering NSR requirements. These include the ability for a source to obtain a synthetic minor source limitation, which restricts its hours of operation and its emissions below major NSR levels, and the Plantwide Applicability Limit (PAL), which allows a source to operate within a source-wide emissions cap to avoid triggering NSR for changes.

The ANPRM solicited input on possible actions that EPA can take to harmonize and streamline the NSR applicability or the NSR permitting processes for an amended rule. EPA requested comment on ways to minimize the impact of the NSR program on the implementation of a performance standard for EGU sources under CAA section 111(d), specifically asking ''[w]hat rule or policy changes or flexibilities can EPA provide as part of the NSR program that would enable EGUs to implement projects required under a CAA section 111(d) plan and not trigger major NSR permitting while maintaining environmental protections?'' 82 FR 61519 (Dec. 28, 2017).

Several ANPRM commenters reiterated concerns that were raised on the CPP proposal regarding the NSR program—specifically that, if an air agency, as part of its plan to comply with emission guidelines established pursuant to CAA section 111(d), requires an affected source to make modifications (*e.g.,* HRI projects), it could potentially trigger major NSR requirements. Some commenters alleged that the NSR program unfairly treats sources that are undertaking changes to become more energy efficient by requiring a costly and time consuming permitting burden. As expressed by one industry representative, ''EGUs engaging in HRI projects can face NSR pre-construction permitting requirements consisting of, at a minimum, costly, detailed analyses and permitting delays. In some cases, this has resulted in costly and protracted litigation, and expensive new emission control requirements, both of which result in substantial time delays for these projects. These concerns remain should unit operators pursue HRI upgrades . . . that could trigger NSR in an effort to comply with . . . revised CAA section 111(d) GHG emissions guidelines.'' [50] Another commenter noted that the major NSR permitting process ''is time and resource intensive'' and, including pre-permit application work, ''can take as long as 3 years or longer.'' [51] The same commenter noted that ''[the] uncertainty of permit timing can hinder investment decisions as much as the actual permit schedule delays.'' [52] Some commenters indicated that the current flexibilities offered within the NSR program are not sufficient to avoid placing a significant permitting burden on EGUs *and* permitting agencies, which could result in substantial delays during the planned implementation stage.[53] To avoid such outcomes, a number of commenters suggested that EPA undertake actions to clarify or change the NSR regulations, including, for example, revising the NSR modification applicability to be based on pounds per kilowatt-hour (lb/kW-h) [54] or rejecting as BSER any project that would result in triggering NSR.[55]

However, other commenters disagreed. For instance, the Natural Resources Defense Council (NRDC) suggested that changes to the NSR program ''are unwarranted.'' [56] They added that EPA needs to remain in the boundary of the controlling judicial decisions in considering what approaches could be used to reduce the number of existing sources that will be subject to NSR permitting while crafting CAA section 111(d) plans. NRDC focused the basis of many of its concerns on the court's opinion in *New York* v. *EPA,* 443 F.3d 880 (D.C. Cir. 2006) (*New York II*), which vacated EPA's attempt to more clearly define ''routine maintenance, repair, and replacement'' (RMRR) projects that are exempt from major NSR by EPA's rules. NRDC also referenced the following observation from an earlier decision by the same court that vacated the ''pollution control project exclusion'' that EPA finalized in 2002: ''Absent clear congressional delegation, however, EPA lacks authority to create an exemption from NSR by administrative rule.'' [57]

D. Proposing NSR Changes for Improved ACE Implementation

1. Overview

EPA acknowledges the NSR program may have unintended consequences for implementation of this emission guidelines for GHG emissions from existing EGUs. Based on the comments received on the ANPRM and EPA's experience with the NSR program generally, EPA recognizes the potential for triggering major NSR permitting when sources undertake HRI projects. EPA further recognizes that the prospect of a protracted permitting process and a possible requirement to install pollution control equipment at the emissions unit can create a disincentive for sources to voluntarily make energy efficiency

[49] Sarah K. Adair, David C. Hoppock, Jonas J. Monast (from Duke University's Nicholas Institute for Environmental Policy Solutions and School of Law, ''*New Source Review and coal plant efficiency gains: How new and forthcoming air regulations affect outcomes*''; Elsevier, Energy Policy 70 (2014), 183–192.

[50] Edison Electric Institute comments on the U.S. Environmental Protection Agency's ANPRM entitled, ''State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,'' 82 FR 61507 (December 28, 2017) at 22 (EPA–HQ–OAR–2017–0545–0221).

[51] General Electric Company (GE) comments on the U.S. Environmental Protection Agency's ANPRM entitled, ''State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,'' 82 FR 61507 (December 28, 2017) at 29–30 (EPA–HQ–OAR–2017–0545–0271).

[52] *Id.* at 30.

[53] *See, e.g.,* Ohio Environmental Protection Agency comments on the U.S. Environmental Protection Agency's ANPRM entitled, ''State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,'' 82 FR 61507 (December 28, 2017) at 9, 32 (EPA–HQ–OAR–2017–0545–0246).

[54] GE comments, *supra* note at 33.

[55] Indiana Municipal Power Agency comments on the U.S. Environmental Protection Agency's ANPRM entitled, ''State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,'' 82 FR 61507 (December 28, 2017) at 3 (EPA–HQ–OAR–2017–0545–0204).

[56] Natural Resources Defense Council comments on the U.S. Environmental Protection Agency's ANPRM entitled, ''State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,'' 82 FR 61507 (December 28, 2017) at 14–17 (EPA–HQ–OAR–2017–0545–0358).

[57] *New York* v. *EPA,* 413 F.3d 3, 41 (D.C. Cir. 2005) (*New York I*) (*citing Sierra Club* v. *EPA,* 129 F.3d 137, 140 (D.C. Cir. 1997)).

improvements. Many of these concerns with the NSR program were raised nearly two decades ago, and formed the cornerstone of EPA's initiative in the early 2000's to reform the NSR program.[58]

But this dynamic takes on a new character in the context of a regulation that may result in a source undertaking a HRI or another project to meet a standard of performance as determined by the state. When a state's 111(d) plan requires an EGU to comply with a standard of performance, sources cannot choose to forego a project in an effort to avoid NSR permitting as they could with improvement projects they were otherwise considering. Despite recent actions by EPA to streamline the NSR program, the reality remains that a source that undertakes a HRI project may trigger major NSR under the current NSR applicability test when required to undertake a HRI project as part of a state's 111(d) plan. As has been noted by commenters on the ANPRM, this can require the source to undertake significant planning and analysis with the process to receive a preconstruction permit, sometimes taking 3 or more years. This added time and cost to sources and the associated burden on permitting agencies could hinder the effective and prompt implementation of state 111(d) plans.

In this context, our approach in the CPP of encouraging agencies to minimize the triggering of major NSR for their affected EGUs by conducting emissions analyses as part of their CAA section 111(d) plan development does not appear to be a sufficient solution. While EPA supports states having the primary authority to implement the air programs, state agencies should not be burdened with having to determine a ''work around'' for the NSR program requirements in developing their plans to implement the emission guidelines for affected EGUs. The responsibility of ensuring that emission guidelines under 111(d) are clearly articulated and easily implementable rests squarely with EPA. Thus, EPA addressing the time delays and costs that can result from NSR requirements could be one tool for helping ensure the successful implementation of a national program for controlling GHG emissions from existing EGUs.

It is important for a state that is developing a CAA section 111(d) plan to completely understand the full costs being imposed on their affected sources in order for the state to make informed decisions in applying a standard of performance to each of their existing sources (much like a state would consider, among other factors, the remaining useful life of each source). However, EPA has historically not considered the costs of complying with other CAA programs, like NSR, when determining BSER for a source category under section 111. This was in part because, for many years, EPA applied a policy of excluding pollution control projects from NSR. But, as noted earlier in this section, EPA's attempt to codify such a policy in the NSR regulations was struck down by the D.C. Circuit in 2005. Since that decision, EPA has not written a significant number of rules under section 111, and the rules that EPA has written have not presented a need to consider this question. However, due to the nature of the electric utility industry and the types of candidate control measures being considered in this proposal, it may be appropriate to consider NSR compliance costs in this instance. Specifically, the BSER measures chosen in this rule may result in a source undertaking a physical change that significantly increases its annual emissions and triggers major NSR permitting requirements such that permitting costs are unavoidable. However, due to the case-specific analysis required to determine NSR applicability, it would likely be difficult for a state to adequately predict and quantify the effect of a HRI on an EGU's operational costs, change in dispatch order, and other variables that would factor into whether the source needs a major NSR permit or, perhaps, a minor NSR permit. In addition, even if a state can reasonably predict an EGU's emissions increase resulting from a HRI project such that it can expect the source will need a major NSR permit, it would likely be difficult to predict the expected permitting costs since the emission control and other permitting requirements are case-by-case determinations and can therefore vary significantly due to a number of factors, including how well the source is already controlled, the emissions from nearby sources and their contribution to air quality concerns, whether the source is located in an attainment or nonattainment area, and the potential for the air permit to trigger other requirements (*e.g.,* Endangered Species Act, National Historic Preservation Act). In some cases, a source triggering major NSR may be required to conduct extensive modeling and install additional pollution controls for non-GHG pollutants. Thus, the case-by-case nature of the NSR program can lead to uncertainty for a state that is creating its 111(d) plan and wanting to ensure that the plan fully appreciates the projected compliance costs for its affected EGUs.

EPA is, therefore, inviting comment on whether it is appropriate to consider the costs of NSR compliance in the BSER analysis under section 111(d), assuming that triggering NSR cannot otherwise be avoided through actions by the source or through revisions to the NSR regulations that are proposed by EPA in this rule or if EPA does not finalize revisions to the NSR regulations (Comment C–59). In addition, EPA solicits comment on how a state or local permitting agency may estimate or project the cost for the source to comply with any NSR requirements that may flow from a selected BSER, and on how the potential for delays because of an influx of NSR permit applications may be accounted for in setting an implementation schedule for 111(d) plans (Comment C–60).

Recognizing that EPA issuing this 111(d) rule would mean that a source may no longer be in a position to forego a HRI project due to unwanted permitting costs, EPA has continued to look for ways to reduce the costs of NSR requirements, while being mindful of the requirements of the CAA and the court decisions on prior NSR reform rules that were referenced by some commenters. In this light, EPA believes that a past option for revising the NSR regulation that EPA has considered may warrant further consideration to address this concern. In 2005 and 2007, EPA previously proposed adopting an hourly emissions rate test for NSR applicability for EGUs. While this rulemaking was never completed, EPA believes that it warrants a fresh look in a new context here where NSR program flexibility takes on added significance as a means to facilitate the HRI projects that are expected to be undertaken should the proposed ACE rule be finalized. This same idea was also raised by a few

[58] In May 2001, President Bush's National Energy Policy Development Group issued findings and key recommendations for a National Energy Policy. This document included numerous recommendations for action, including a recommendation that the EPA Administrator, in consultation with the Secretary of Energy and other relevant agencies, review NSR regulations, including administrative interpretation and implementation. The recommendation requested that EPA issue a report to the President on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection. The report to the President was issued on June 13, 2002, and is available at *https://www.epa.gov/nsr/new-source-review-report-president.* In the report to the President, EPA concluded ''[as] applied to existing power plants and refineries . . . the NSR program has impeded or resulted in the cancellation of projects which would maintain and improve reliability, efficiency and safety of existing energy capacity. Such discouragement results in lost capacity, as well as lost opportunities to improve energy efficiency and reduce air pollution.'' New Source Review Report to the President at 3.

commenters on the ANPRM.[59] Thus, EPA is soliciting comment on whether a narrower range of options for implementing an hourly emissions test for NSR for EGUs would both help promote energy efficiency and the effectiveness of implementing the ACE rule, while at the same time being consistent with the NSR provisions in CAA and past judicial decisions interpreting those provisions (Comment C–61).

2. The 2007 Supplemental Rule Proposal

In 2007, EPA proposed to revise the NSR provisions to include an NSR applicability test for EGUs that is based on maximum hourly emissions. 72 FR 26202 (May 8, 2007). The 2007 proposed action was a ''supplemental'' notice of proposed rulemaking (SNPRM), because the 2007 proposal followed an earlier action by EPA that proposed a more limited form of the hourly emissions test for NSR applicability. 70 FR 61081 (October 20, 2005) (NPRM). These proposals followed EPA's NSR regulatory reform efforts of 2002 and 2003, when EPA promulgated final regulations that implemented several of the recommendations in the New Source Review Report to the President.[60] Those earlier regulatory actions, however, left the NSR provisions for electric utilities largely unchanged.

The 2007 SNPRM requested comment on two basic options, and various alternatives within each of the two options, for changing the test for determining an emissions increase from an EGU undergoing a physical or operational change. The proposal included emissions test alternatives based on an EGU's maximum *achieved* hourly emissions rate—applying either a ''statistical approach'' or a ''one-in-5-year baseline approach''—and an EGU's maximum *achievable* hourly emissions rate, which mirrored the NSPS modification applicability test. While EPA did not propose rule amendments in the 2005 NPRM, in 2007 EPA proposed to amend 40 CFR part 51 to include a new provision at § 51.167, which largely mirrored the NSPS modification provisions in § 60.2 and § 60.14. The 2007 SNPRM provided EPA's legal and policy basis for incorporating an hourly emissions increase test within the NSR program for EGUs.

For the proposed maximum achieved hourly test alternatives, an EGU owner/operator would determine whether an emissions increase would occur by comparing the pre-change maximum actual hourly emissions rate to a projection of the post-change maximum actual hourly emissions rate. In establishing the baseline, both alternatives considered the unit's actual performance during the 5-year period immediately preceding the physical or operational change. For the one-in-5-year baseline approach, the emissions rate would be computed based on what the unit actually achieved for any single hour within the 5-year period immediately before the physical or operational change. For the statistical approach, the owner/operative would analyze continuous emission monitoring system (CEMS) or predictive emission monitoring system (PEMS) data from the 5 years preceding the physical or operational change to determine the maximum actual pollutant emissions rate. The statistical approach would utilize actual recorded data from periods of representative operation to calculate the maximum actual emissions rate associated with the pre-change maximum actual operating capacity in the past 5 years.

The purpose behind developing the statistical approach was to address concerns from comments received on the 2005 NPRM ''that maximum achievable emissions could differ from maximum achieved emissions for a given EGU for any given period as a result of factors independent of the physical or operational change, including variability of the sulfur content in the coal being burned.'' 72 FR 26219 (May 8, 2007). In the 2007 SNPRM, EPA acknowledged that the highest hourly emissions do not always occur at the point of highest capacity utilization, due to fluctuations in process and control equipment operation, as well as in fuel content and firing method. The proposed statistical procedure would consequently ensure that the maximum achieved hourly emissions test identified the maximum hourly pollutant emissions value. Specifically, the statistical procedure would estimate the highest value (99.9 percentage level) in the period represented by the data set compiled from hourly average CEMS or PEMS measured emission rates and corresponding heat input data. EPA asserted that this approach would mitigate some of the uncertainty associated with trying to identify the highest hourly emissions rate at the highest capacity utilization. EPA asserted then that ''over a period that is representative of normal operations, in general the maximum achievable and maximum achieved hourly emissions test would lead to substantially equivalent results.'' 72 FR 26220.

For the proposed maximum achievable hourly test alternatives, the major NSR regulations would apply at an EGU if a physical or operational change results in any increase above the maximum hourly emissions achievable at that unit during the 5 years prior to the change. Pre-change and post-change hourly emissions rates would be determined according to the NSPS provisions in § 60.14(b). Hourly emission increases would be determined using emission factors, material balances, continuous monitor data, or manual emission tests.

In the 2007 SNPRM, EPA argued that a maximum hourly emissions test would simplify major NSR applicability determinations and implementation. EPA contended that ''the achieved and achievable [hourly emissions] tests eliminate the burden of projecting future emissions and distinguishing between emissions increases caused by the change from those due solely to demand growth, because any increase in the emissions under the hourly emissions tests would logically be attributed to the change. Both the achieved and achievable tests reduce recordkeeping and reporting burdens on sources because compliance will no longer rely on synthesizing emissions data into rolling average emissions.'' 72 FR 26206 (May 8, 2007).

While the 2005 action had proposed to replace the current NSR annual emissions increase test with an hourly test, the 2007 action proposed the same option as well as an option to retain the annual emissions test along with an hourly test. For the combined hourly and annual emissions option, if a change would not increase the hourly emissions of the EGU, major NSR would not apply; however, if hourly emissions would increase after the change, then projected annual emissions would be reviewed using the existing NSR applicability test. The 2007 SNPRM expressed a preference for this combined applicability option.

In the 2007 SNPRM, the proposed changes to the NSR emissions test were in part justified by the substantial EGU emission reductions from other air programs enacted since 1980 and the capped emissions approaches used for

[59] *See, e.g.,* Arizona Public Service Company comments on the U.S. Environmental Protection Agency's ANPRM entitled, ''State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,'' 82 FR 61507 (Dec. 28, 2017) at 6 (EPA–HQ–OAR–2017–0545–0286);Unions for Jobs & Environmental Progress comments on the U.S. Environmental Protection Agency's ANPRM entitled, ''State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units,'' 82 FR 61507 (Dec. 28, 2017) at 14–17 (EPA–HQ–OAR–2017–0545–0162).

[60] *See supra* note.

SO_2 and nitrogen oxides (NO_X) since the CAA Amendment of 1990. The analyses conducted for that 2007 SNPRM concluded that, by 2020, more EGUs would install controls than they would in complying with a number of emission cap-based EPA rules that were in play at the time (*i.e.,* Clean Air Interstate Rule, Clean Air Mercury Rule, and Clean Air Visibility Rule). The analysis maintained that the hourly emissions test would allow units to operate more hours each year, and the more hours a unit operates, the more it will control emissions to remain under the emission caps. It concluded that there would be essentially no changes in national emissions of SO_2 and NO_X by coal-fired power plants, and essentially no impact on county-level emissions or local air quality.

These 2005 and 2007 proposed rules were neither finalized nor withdrawn by EPA. The rulemaking docket for these actions is EPA–HQ–OAR–2005–0163.

3. Legal Basis for Using Hourly Emission Rates To Identify Increases in Emissions

The 2007 SNPRM followed EPA's NPRM from 2005 that would have *replaced* the NSR program's annual emissions test with an hourly test. The proposed regulatory approach taken in 2005 was based on the decision in *United States* v. *Duke Energy Corp.,* 411 F.3d 539 (4th Cir. 2005), in which the court held that the NSPS and NSR programs must have a uniform emissions test. There, in the context of an NSR enforcement case, the meaning of the CAA's definition of ''modification,'' and the proper interpretation of the provisions of the NSR regulations (as promulgated in 1980) that spoke to how an ''emissions increase'' was to be determined were at issue. The Fourth Circuit held that the CAA requires that those NSR regulations ''conform'' to their NSPS counterpart. 411 F.3d at 548. According to the Fourth Circuit, because Congress had relied on a cross-reference to CAA section 111(a)(4)'s definition of ''modification'' (*i.e.,* the original NSPS definition) to define ''modification'' for purposes of the NSR program, this created an ''effectively irrebuttable presumption'' that the two definitions must be the same.'' *Id.* at 550.

The case then went to the Supreme Court, and the Supreme Court disagreed. In *Environmental Defense* v. *Duke Energy Corporation,* 549 U.S. 561 (2007), the Supreme Court held that there was ''no effectively irrebuttable presumption that the same defined term in different provisions of the same statute must be interpreted identically. Context counts.'' 549 U.S. at 575–76 (internal citation and quotation marks omitted). Moving beyond the procedural question of whether the Fourth Circuit had applied the proper tools of statutory construction, the Court also engaged the underlying substantive question, finding that ''[n]othing in the text or the legislative history'' suggests that Congress intended to *require* that the programs be tied together and thereby ''eliminat[e] the customary agency discretion to resolve questions about a statutory definition by looking to the surroundings of the defined term.'' *Id.* at 576.

Of particular significance here, the Supreme Court also addressed the possibility that the two regulatory programs could be read together as set and subset, such than an NSPS-type modification was a prerequisite to an NSR-type modification—*i.e.,* that ''before a project can become a 'major modification' under the PSD regulations, it must meet the definition of 'modification' under the NSPS regulations.'' 549 U.S. at 581 n.8. This reading ''sounds right,'' the Court opined,'' but then observed that, in its view, the NSPS and NSR regulations as they were then written did not support such a reading. *Id.* Although the Court had no occasion to address whether the Clean Air Act *allows,* rather than directs, EPA to define ''modification'' the same way in both the NSPS and NSR programs, EPA believes that the answer is clearly yes. The Court does generally ''presume that the same term has the same meaning when it occurs here and there in a single statute,'' 549 U.S. at 575, and, as Justice Thomas pointed out in his concurrence, in the case of the CAA's definition of ''modification,'' Congress's use of a cross-reference ''carries more meaning than mere repetition of the same word in a different statutory context.'' *Id.* at 583 (Thomas, J., concurring).[61]

In the 2007 SNPRM, EPA argued that the Supreme Court decision left room for EPA to revise the regulations when it has a rational basis for doing so. 72 FR 26202, 26204 (May 8, 2007); *see also Environmental Defense* v. *Duke Energy Corp.,* 549 U.S. 561, 576 (2007) (''EPA's construction [of the definition of modification] need do no more than fall within the limits of what is reasonable, as set by the Act's common definition.'') EPA also argued that a maximum hourly emissions test for NSR is an appropriate exercise of EPA's discretion citing *Chevron U.S.A., Inc.* v. *NRDC, Inc.* 467 U.S. 37,865 (1984). *Chevron* provides that when a statute is silent or ambiguous with respect to a specific issue, the relevant inquiry for a reviewing court is whether the Agency's interpretation of the statutory provision is permissible. In this case, the Clean Air Act is silent on how to determine whether a physical change or change in method of operation ''increases the amount of any air pollutant emitted.'' 42 U.S.C. 7411(a)(4); *New York I,* 413 F.3d at 22 (''[T]he CAA . . . is silent on how to calculate such 'increases' in emissions.''). Accordingly, EPA has broad discretion to propose a reasonable method by which to calculate the ''amount'' of an emissions ''increase'' for purposes of NSR applicability.

In the 2007 action, EPA also explained how an applicability test based on maximum achievable hourly emissions is, in fact, a test based on actual emissions. The reason is that, as a practical matter, ''for most, if not all EGUs, the hourly rate at which the unit is actually able to emit is substantively equivalent to that unit's historical maximum hourly emissions. That is, most, if not all EGUs will operate at their maximum actual physical and operational capacity at some point in a 5-year period. In general, the highest emissions occur during the period of highest utilization. As a result, both the maximum achievable and maximum achieved hourly emissions increase tests allow an EGU to utilize all of its existing capacity, and in this aspect the hourly rate at which the unit is actually able to emit is substantively equivalent under both tests.'' 72 FR 26219 (May 8, 2007).

Thus, EPA considered the approaches proposed in the 2007 SNPRM to be consistent with the D.C. Circuit precedent which held that the 2002 NSR Reform Rule's ''Clean Unit'' provision was beyond EPA's authority because Congress intended to apply NSR to increases in actual emissions, even though the decision deferred to EPA on the method for calculating baseline emissions. *Compare New York I,* 413 F.3d at 40 *with id.* at 20. In *New York I,* the D.C. Circuit found that the ''Clean Unit'' provision was unlawful because it ''measures 'increases' in terms of Clean Unit status instead of actual emissions.'' 413 F.3d at 39. In defense of the provision, EPA had asserted that the CAA is ''silent'' as to whether an emissions increase ''must be measured in terms of actual emissions, potential

[61] To this point, as Justice Thomas explains, the majority's analysis of the relationship between the NSR and NSPS programs is dicta, because the NSR regulations, as then written, could not be permissibly read to mean the same as the NSPS regulations, and CAA section 307(b) prohibits review of the NSR regulations in the context of an enforcement action. *Duke Energy,* 549 U.S. at 582 (Thomas, J. concurring) (explaining that Justice Thomas joins only Part III.B of the majority opinion).

emissions, or some other currency,'' and that EPA was therefore owed deference to interpret what type of ''increases'' are relevant for the modification analysis. *Id.* The D.C. Circuit, however, disagreed. The court found that section 111(a)(4)'s reference to ''the *amount* of any air pollutant *emitted* by [the] source plainly refers to actual emissions'' and cannot encompass potential emissions. *Id.* at 40 (emphases in original). According to the court, ''the plain language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions.'' *Id.*

At the same time, the D.C. Circuit affirmed that EPA has wide discretion to interpret the definition of ''modification'' within these bounds. The court rejected challenges brought to the 2002 NSR Reform Rule's then-new baseline period provision, finding that ''[i]n enacting the NSR program, Congress did not specify how to calculate 'increases' in emissions,'' with the result that it was left to EPA ''to fill that gap while balancing the economic and environmental goals of the statute.'' 413 F.3d at 27. Because the CAA is ''silent on how to calculate . . . 'increases' in emissions'' for purposes of determining ''modification,'' the court said, *id.* at 22, EPA has discretion to give meaning to that term by adopting a baseline period that '' 'represents a reasonable accommodation of' '' the Agency's environmental, economic, and administrative concerns. *Id.* at 23 (*quoting Chevron,* 467 U.S. at 845). The D.C. Circuit went on to say that ''[d]ifferent interpretations of the term 'increases' may have different environmental and economic consequences,'' and in ''administering the NSR program and filling in the gaps left by Congress, EPA has the authority to choose an interpretation that balances those consequences.'' *Id.* at 23–24. The court added that this choice may be informed by both EPA's ''extensive experience and expertise'' in this technical and complex regulatory program and by the ''incumbent administration's view of wise policy.'' *Id* at 24.

As for NRDC's argument in comments on the ANPRM that narrowing the scope of projects subject to NSR requirements would be contrary to the D.C. Circuit's *New York II* decision, EPA notes that what was before the court in that case was an effort by EPA to further define what type of projects are considered RMRR and thus excluded from the types of ''physical change[s] in, or change[s] in the method of operation of'' a source that may trigger NSR. *New York II,* 443 F.3d at 883. While the case focused on the ''physical change'' criterion of ''modification,'' the court's decision does provide some guidance on EPA's discretion to interpret ''emissions increase.'' The court in *New York II* found that the Equipment Replacement Rule, as promulgated in 2003, violated the CAA because its bright-line RMRR test, which took into account the value of the particular components being replaced, was inconsistent with CAA section 111(a)'s broad applicability to ''any physical change'' that results in increased emissions, subject to only *de minimis* exclusions. *Id.* at 890. But in so finding, the D.C. Circuit contrasted what it found to be the clear meaning of ''any physical change'' with ''Congress's use of the word 'increase,' '' which ''necessitated further definition regarding rate and measurement for the term to have any contextual meaning.'' *Id.* at 888–889. Accordingly, contrary to NRDC's assertions, *New York II* confirms the finding in *New York I* that, other than requiring that they be measured in terms of actual emissions, the CAA leaves to EPA the discretion to determine how emission increases will be defined for the purposes of NSR modification.

4. This Proposal

Consistent with our policy goal of encouraging efficient use of existing energy capacity and managing the burden on states of developing and implementing their CAA section 111(d) plans, EPA is proposing to amend the NSR regulations to include an hourly emissions increase test for EGUs. These proposed changes could be one tool that states may use to help ensure the efficient and effective implementation of their 111(d) plans.[62]

EPA is proposing some of the same alternatives for an hourly emissions test that EPA proposed in 2007. The 2007 SNPRM solicited comment on 12 alternatives, but EPA is narrowing the number of alternatives for this revised proposal and solicitation of comment. In this case, EPA is proposing only alternatives in which the hourly test is paired with the current NSR annual emissions test (*i.e.,* Option 1 in the 2007 SNPRM) and only the alternatives that have an input-based format (*i.e.,* Alternatives 1, 3, and 5 in the 2007 SNPRM). Table 1 reflects the three alternatives being proposed in this action, and how they fit within the structure of the proposed combined annual and hourly emissions test for NSR applicability.

TABLE 5—PROPOSED MAJOR NSR APPLICABILITY FOR AN EXISTING EGU [63]

Step 1: Physical Change or Change in the Method of Operation.
Step 2: Hourly Emissions Increase Test.
- Alternative 1—Maximum achieved hourly emissions; statistical approach; input basis.
- Alternative 2—Maximum achieved hourly emissions; one-in-5-year baseline; input basis.
- Alternative 3—Maximum achievable hourly emissions; input basis.

Step 3: Significant Emissions Increase Determined Using the Actual-to-Projected-Actual Emissions Test as in the Current NSR Rules.
Step 4: Significant Net Emissions Increase as in the Current NSR Rules.

Thus, under this proposed approach, the major NSR program would include a four-step applicability process (with the second step inserted as proposed, while retaining the other steps): (1) A physical change or change in the method of operation as in the current major NSR regulations; (2) an hourly emissions increase test (either maximum achieved hourly emissions rate or maximum achievable hourly emissions rate, each on an input-basis (lb/hr)); (3) a significant emissions increase as in the current major NSR regulations; and (4) a significant net emissions increase as in the current major NSR regulations. For a major modification to occur, under Step 1, a physical change or change in the method of operation must occur. If there is a physical change or change in

[62] As noted above, EPA is inviting comment regarding whether, if we do not address NSR permitting burden with this proposal, we should provide a mechanism for state and local permitting agencies to consider the costs and delays associated with NSR permitting. *See* Section VIII.C.1 of this preamble.

[63] For clarity, this table lists all of the steps in the NSR major modification applicability determination under the three alternatives being proposed in this action. This current action does not propose to change any of the current NSR applicability steps besides inserting Step 2.

method of operation, under Step 2, that change must result in an hourly emissions increase at the existing EGU. If a post-change hourly emissions increase is projected, a source must then proceed to determine whether there is also a significant emissions increase and a significant net emissions increase. In such cases, under Step 3, the owner/operator would determine whether an emissions increase would occur using the actual-to-projected-actual annual emissions test as provided in the current regulations. There would be no conversion from annual to hourly emissions. Finally, in Step 4, as in the current regulations, if a significant emissions increase is projected to occur, the source would still not be subject to major NSR unless there was a determination that a significant net emissions increase would occur.

This proposed approach would not alter the provisions in the current major NSR regulations pertaining to a significant emissions increase and a significant net emissions increase. Therefore, the NSR regulations would retain the definitions of net emissions increase, significant, projected actual emissions, and baseline actual emissions. *See* 40 CFR 51.166(b)(3), 51.166(b)(23), 51.166(b)(40), 51.166(b)(47).[64] The regulations would also retain all provisions in the current regulations that refer to major modifications, including, but not limited to, those in 40 CFR 51.166(a)(7)(i) through (iii), (b)(9), (b)(12), (b)(14)(ii), (b)(15), (b)(18), (i)(1) through (9), (j)(1) through (4), (m)(1) through (3), (p)(1) through (7), (r)(1) through (7), and (s)(1) through (4).[65]

To incorporate the four-step modification provisions, EPA is proposing to add two new sections to the major NSR program rules. The first, 40 CFR 51.167, would specify that State Implementation Plans may include a new Step 2 for major NSR applicability at existing EGUs, including those for both attainment and nonattainment areas. The second, 40 CFR 52.25, would contain the requirements for major NSR applicability for existing EGUs where EPA is the reviewing authority or EPA has delegated our authority to a state or local air permitting agency. EPA is also proposing to make the same changes where necessary to conform the general provisions in parts 51 and 52 to the requirements of the major NSR program, such as in the definition of modification in 40 CFR 52.01. The new sections at § 51.167 and § 52.25 will be separate and distinct from the other NSR provisions and this will allow our rules to apply this new proposed Step 2 to EGUs while keeping the current distinction in our NSR rules that applies different applicability requirements for EUSGUs and non-EUSGUs that are not EGUs.

While EPA is proposing that this NSR hourly emissions test would apply to all EGUs, as defined in 40 CFR 51.124(q), EPA is soliciting comment on whether to confine the applicability of the hourly test to a smaller subset of the power sector, such as only the affected EGUs that are making modifications to comply with their state's standards of performance pursuant to these section 111(d) emissions guidelines (*i.e.,* pursuant to this document's proposed provisions at § 60.5775a and § 60.5780a) (Comment C–62). In addition, while the 2007 SNPRM solicited comment on whether such a test should be limited to the geographic areas covered by several of EPA's rules at the time, because the ACE rule would potentially affect EGUs in all of the contiguous U.S., EPA is proposing in this action to not limit its applicability to specific geographic areas. We are specifically proposing that it would apply to EGUs in all areas of the United States. Finally, although the 2007 SNPRM requested comment on whether the proposed NSR hourly emissions test should be limited to increases of SO_2 and NO_X emissions (due to the analysis that supported the 2007 SNPRM), EPA is proposing in this action that the NSR hourly emissions test would apply to all regulated NSR pollutants because the candidate technologies being considered under this proposal may affect annual emissions of not only GHGs but of all pollutants from the power sector (and because EPA is not relying on the previous proposal's analysis that focused on SO_2 and NO_X emissions). EPA solicits comment on these approaches to applicability for the proposed NSR hourly emission increase test.

Recognizing that existing case law dictates that the phrase ''increases the amount of any air pollutant'' in CAA section 111(a)(4) refers to increases in actual emissions for NSR purposes, in 2007 EPA argued that an hourly achievable test is equivalent to a measure of actual emissions because ''for most, if not all EGUs, the hourly rate at which the unit is actually able to emit is substantively equivalent to that unit's historical maximum hourly emissions.'' 72 FR 26219 (May 8, 2007). EPA is taking comment on this prior assertion and whether recent changes to the energy sector may have rendered it invalid (Comment C–63). EPA is also asking for comment on whether if, practically speaking, maximum achieved and maximum achievable hourly rates are equivalent for most if not all EGUs, EPA has the flexibility under the CAA to implement an hourly achievable emissions test for NSR (Comment C–64).

As noted in the preceding section, EPA's proposal in 2007 to adopt an hourly emissions increase test for NSR included an analysis demonstrating that (1) the proposed regulations would not have an undue adverse impact on local air quality, and (2) increases in the hours of operation at EGUs, to the extent they may increase under a maximum hourly rate test for NSR, would not notably increase national SO_2, NOx, $PM_{2.5}$, VOC, or CO emissions from the power sector. The analysis in 2007 concluded that the more efficiently and the more cost-effectively an EGU operates, the more likely it is to install controls due to other EPA air regulations. While time has passed since the analyses in the 2007 SNPRM were conducted, the analysis conducted for the ACE rule similarly reflects that, for scenarios that include varying levels and costs of efficiency improvements (reflecting, in part, the proposed changes to NSR in this action), total national emissions of CO_2 and other pollutants will essentially stay the same or be slightly reduced when compared with a CPP repeal. While it is possible that some individual units may experience an increase in annual emissions due to increases in operation, it is very difficult to project with confidence at which of the units this would actually occur. This is partly due to the framework of the current NSR annual emissions test, which considers a number of source-specific variables—including operational history of the unit, projected emissions that may be exempted due to demand growth, other units competing for dispatch, and availability of creditable emission decreases at the facility—that could result in the source ultimately not being subject to major NSR. Consequently, the analysis conducted for the ACE rule estimates the cost and benefits of the different scenarios in a categorical sense and does not attempt to identify the particular sources at which major NSR permitting may be required absent the type of revisions to the NSR regulations proposed here or incorporate a specific cost for NSR permitting within any of the scenarios. This is due in part to limitations in the feasibility of such analysis and in part to the structure of

[64] Analogous provisions are found in 40 CFR 51.165, 52.21, and appendix S to 40 CFR part 51.

[65] Analogous provisions are found in 40 CFR 51.165, 52.21, and appendix S to 40 CFR part 51.

section 111(d) and the state-plan development phase which would follow a finalization of this proposed rule. EPA requests comment on the concern about the potential emission increases as part of the proposed NSR changes that some stakeholders have raised (Comment C–65).

While recognizing that fewer sources will trigger major NSR under an hourly emissions increase, we note that even if a source undertaking a heat rate improvement is not subject to major NSR requirements, it will often require a minor NSR permit from its permitting agency. As noted in Section VIII.A of this preamble, the minor NSR program applies to new and modified sources that are not subject to major NSR permitting. The purpose of a minor NSR program is, along with major NSR, to ensure that sources of air emissions are properly regulated so that the NAAQS are attained and protected. For example, under EPA's tribal minor NSR program, the reviewing authority (*i.e.,* EPA or a delegated Tribe) must ensure that the NAAQS are protected through the permitting process. The reviewing authority has the option to require an air quality impact analysis for individual permits if they deem it necessary based on air quality concerns.[66] All minor NSR permits require a public notice process and the permit may potentially require the installation of air pollution controls based on an assessment by the permitting authority.

Furthermore, states use measures contained in their State Implementation Plan (SIP) to ensure that local air quality impacts are addressed or minimized to the extent possible. A SIP may include (1) state-adopted control measures which consist of either regulations or source-specific requirements (*e.g.,* orders and consent decrees); (2) state-submitted ''non-regulatory'' components (*e.g.,* maintenance plans and attainment demonstrations); and (3) additional requirements promulgated by EPA to satisfy a mandatory requirement in Section 110 or Part D of the CAA.

Supplementing the Agency's legal and policy rationale provided in the 2007 SNPRM, EPA is taking comment on an important factor that EPA believes supports for moving forward with the addition of an NSR hourly emissions test for EGUs: EPA is now proposing a rule that could result in sources being required to perform HRIs (as determined by their state 111(d) plans) rather than sources independently deciding to do them (Comment C–66). EPA believes this added factor of the 111(d) GHG emission guidelines for EGUs directing sources to consider HRIs when complying with their state plans may make the case for adopting an NSR hourly emissions test for EGUs more compelling. EPA requests comment on the extent to which EPA should allow the adoption of an NSR hourly emissions test for EGUs in light of EPA's decision to issue these proposed emission guidelines for the power sector (Comment C–67).

EPA is also taking comment on other ways to minimize or eliminate any adverse impact that NSR may have on implementing section 111(d) plans for EGUs (Comment C–68). Specifically, have there been court decisions since *New York I* and *New York II* that can be read to afford EPA more flexibility with respect to its reading of the definition of ''modification'' in the context of the NSR program?

For example, when EPA undertook the challenge of applying the PSD program to GHGs, the Supreme Court pointed to several instances where EPA had permissibly narrowed the scope of the general CAA definition of ''air pollutant'' based on the surrounding context of provisions within which the term is used, including the NSR program. *UARG* v. *EPA,* 134 S.Ct. 2427, 2439–41 (2014). Based in part on this observation, the Court rejected EPA's strict interpretation that the term ''air pollutant'' must apply to greenhouse gases in the context of the definition of ''major emitting facility'' in section 169(1) of the Act in spite of the Agency's recognition that such a reading would dramatically expand the reach of the PSD program to smaller scale construction that Congress had never intended to cover. *Id.* at 2442. In a like manner, does EPA have more flexibility with regard to its interpretation of the definition of ''modification'' in the context of the PSD program than the D.C. Circuit has previously recognized? Where the D.C. Circuit's reading of the definition of ''modification'' in the PSD context would produce results that frustrates Congressional objectives in the CAA section 111 programs, does the reasoning of the Supreme Court in *UARG* supply a basis for EPA to develop a narrower form of a pollution control project exclusion from NSR?

The requirements of the CAA section 111 program were intended to work in harmony with NSR and other provisions of the Act. The complementary relationship of the programs is evident from the statutory requirements. Both programs are intended to protect air quality from stationary sources of pollution, and they rely on many of the same CAA provisions and definitions—namely, the programs' framework for existing sources are both rooted in the same definition for ''modification.'' In addition, there are instances in which the CAA cross links the programs such that a requirement from one program bears an influence on the other program. For example, in accordance with CAA section 169(3), an applicable standard of performance under NSPS establishes the minimum level of stringency for BACT for a source getting a PSD permit. Similarly, LAER must reflect an emission rate that is does not exceed the allowable emission rate under any applicable NSPS. CAA section 171(3). Thus, the NSPS program sets the minimum performance standards for new stationary sources as part of program to ensure air quality is protected, and NSR authorizes the construction or modification of sources of air pollution, taking into account the NSPS as it examines what the source needs to do to control its emissions in order to adequately protect or improve air quality.

Thus, EPA believes the two programs are intended to complement—not conflict with—each other. However, because changes considered under 111(d) plans could result in a source triggering NSR under the current NSR rules and increasing the costs to the point that undertaking HRI are less financially feasible for some sources, can EPA apply the reasoning of *UARG* to read the definition of ''modification'' in this context to afford more flexibility to exempt sources from NSR requirements when they are compelled to make changes by an NSPS (Comment C–69)?

5. State Adoption

As the hourly emissions test for NSR would be one tool for implementing the ACE rule, EPA expects that some states may determine that they do not need or desire to change the NSR applicability requirements for EGUs. Consequently, EPA does not intend the NSR hourly emissions test to be a mandatory element of state programs (as EPA had proposed in 2007). EPA is proposing for this action that states would have the discretion to decide whether to incorporate the NSR hourly emissions test for EGUs into their rules. However, state and local permitting authorities that are issuing permits on behalf of EPA under a delegation agreement will be required to apply the NSR hourly emissions test for EGUs, since they would follow the Federal NSR program provided in 40 CFR part 52 (which would be amended to include section

[66] 40 CFR 49.154(d). We note that many state (and local) minor NSR permitting programs have similar methods for ensuring that the NAAQS are protected.

52.25). EPA solicits comment on allowing states this flexibility to adopt the proposed NSR rule changes and on any other considerations with respect to state (or local/district agency) adoption and implementation of the proposed NSR changes (Comment C–70).

6. Severability

Although EPA proposes to finalize these NSR revisions as part of an integrated action with the rest of this proposal, EPA views the revisions to the definition of BSER, revisions to the implementing regulations, and emission guideline proposed in this proposal as appropriate policies in their own right and on their own terms. EPA intends that the NSR revisions, if finalized, would be severable from the other provisions on judicial review. EPA solicits comment on whether it would be appropriate to finalize the NSR revisions as a separate action from the remainder of the proposal (Comment C–71).

7. Submitting Comments

Please submit all comments on this NSR section docket established for this rulemaking (Docket ID number EPA–HQ–OAR–2017–0355). To the extent that you previously commented on the October 20, 2005 NPRM and/or May 8, 2007 SNPRM and desire for your comments to be considered for this proposed action, please resubmit them.

IX. Impacts

A. What are the air impacts?

In the Regulatory Impact Analysis (RIA) for this proposed rulemaking, the Agency provides a full benefit cost analysis of four illustrative scenarios. The four illustrative scenarios include a scenario modeling the full repeal of the CPP (which can also be conceptualized as the legal state of affairs as of the date of this proposal, given the Supreme Court stay of the CPP) and three policy scenarios modeling heat rate improvements (HRI) at coal-fired EGUs. Throughout the RIA, these three illustrative policy scenarios are compared against a base case, which includes the CPP. By analyzing against the CPP, the reader can understand the combined impact of the CPP repeal and proposed ACE rule. Inclusion of a no CPP case allows for an understanding of the repeal alone and also allows the reader to evaluate the impact of the policy cases against a no CPP scenario. The RIA assumes a mass-based implementation of the CPP for existing affected sources, and does not assume interstate trading. The three illustrative policy scenarios represent potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs. These policy scenarios illustrate the analysis of the world without the CPP, the world with this proposal, and the difference in the effects of this proposal and those of the CPP.

The illustrative policy scenarios model different levels and costs of HRIs applied uniformly at all affected coal-fired EGUs in the contiguous U.S. beginning in 2025. EPA has identified the BSER to be HRI. Each of these illustrative scenarios assumes that the affected sources are no longer subject to the state plan requirements of the CPP (*i.e.,* the mass-based requirements assumed for CPP implementation in the base case for the RIA). The cost, suitability, and potential improvement for any of these HRI technologies is dependent on a range of unit-specific factors such as the size, age, fuel use, and the operating and maintenance history of the unit. As such, the HRI potential can vary significantly from unit to unit. EPA does not have sufficient information to assess HRI potential on a unit-by-unit basis. To avoid the impression that EPA can sufficiently distinguish likely standards of performance across individual affected units and their compliance strategies, this analysis assumes different HRI levels and costs are applied uniformly to affected coal-fired EGUs under each of three illustrative policy scenarios:

The first illustrative scenario, 2 Percent HRI at $50/kW, represents a policy case that reflects modest improvements in HRI absent any revisions to NSR requirements. For many years, industry has indicated to the Agency that many sources have not implemented certain HRI projects because the burdensome costs of NSR cause such projects to not be viable. Thus, absent NSR reform, HRI at affected units might be expected to be modest. Based on numerous studies and statistical analysis, the Agency believes that the HRI potential for coal-fired EGUs will, on average, range from one to three percent at a cost of $30 to $60 per kilowatt (kW) of EGU generating capacity. The Agency believes that this scenario (2 percent HRI at $50/kW) reasonably represents that range of HRI and cost.

The second illustrative scenario, 4.5 Percent HRI at $50/kW, represents a policy case that includes benefits from the proposed revisions to NSR, with the HRI modeled at a low cost. As mentioned earlier, the Agency is proposing revisions to the NSR program that will provide owners and operators of existing EGUs greater ability to make efficiency improvements without triggering the provisions of NSR. This scenario is informative in that it represents the ability of all coal-fired EGUs to obtain greater improvements in heat rate because of NSR reform at the $50/kW cost identified earlier. EPA believes this higher heat rate improvement potential is possible because without NSR a greater number of units may have the opportunity to make cost effective heat rate improvements such as steam turbine upgrades that have the potential to offer greater heat rate improvement opportunities.

The third illustrative scenario, 4.5 Percent HRI at $100/kW, represents a policy case that includes the benefits from the proposed revisions to NSR, with the HRI modeled at a higher cost. This scenario is informative in that it represents the ability of a typical coal-fired EGU to obtain greater improvements in heat rate because of NSR reform but at a much higher cost ($100/kW) than the $50/kW cost identified earlier. Particularly for lower capacity units or those with limited remaining useful life, this could ultimately translate into HRI projects with costs beyond what most states might determine to be reasonable.

Combined, the 4.5 percent HRI at $50/kW scenario and the 4.5 percent HRI at $100/kW scenario represent a range of potential costs for the proposed policy option that couples HRI with NSR reform. Modeling this at $50/kW and $100/kW provides a sensitivity analysis on the cost of the proposed policy including NSR reform. The $50/kW cost represents an optimistic bounding where NSR reform unleashes significant new opportunity for low-cost heat rate improvements. The $100/kW cost scenario, while informative, represents a high-end bound that could overstate potential because, particularly for lower capacity factor units and those with limited remaining useful life, these would represent project costs that states would likely find to be unreasonable.

The Agency understands that there may be interest in comparing the three illustrative policy scenarios against an alternative baseline that does not include the CPP. For those interested in comparing the potential impacts of the policy scenarios in a world without the CPP, results from the three illustrative policy scenarios may be compared against an alternative baseline results from the illustrative No CPP scenario. The presentation of an alternative baseline is consistent with Circular A–4, which states, ''When more than one baseline is reasonable and the choice of baseline will significantly affect estimated benefits and costs, you should consider measuring benefits and costs against alternative baselines'' [67] In addition, the full suite of model outputs and additional comparisons tables are available in the rulemaking docket.

EPA evaluates the potential regulatory impacts of the illustrative No CPP scenario and the three illustrative policy scenarios using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2023–2037 from the perspective of 2016, using both a three percent and seven percent beginning-of-period discount rate. In addition, the Agency presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. In the RIA, the regulatory impacts are evaluated for the specific years of 2025, 2030, and 2035.

Emissions are projected to be higher under the three illustrative policy scenarios and the illustrative No CPP scenario than under the base case, as the base case includes the CPP. Table 6 shows projected emission increases relative to the base case for CO_2, SO_2 and NO_X from the electricity sector. Table 7 shows the same emissions change information, except relative to the No CPP alternative baseline.

TABLE 6—PROJECTED CO_2, SO_2, AND NO_X ELECTRICITY SECTOR EMISSION INCREASES, RELATIVE TO THE BASE CASE (CPP) (2025–2035)

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
No CPP			
2025	50	36	32
2030	74	60	47
2035	66	44	43
2% HRI at $50/kW			
2025	37	35	24
2030	61	53	39
2035	55	34	39
4.5% HRI at $50/kW			
2025	32	40	21
2030	60	53	39
2035	59	43	43
4.5% HRI at $100/kW			
2025	20	32	14
2030	47	45	32
2035	44	29	33

TABLE 7—PROJECTED CO_2, SO_2, AND NO_X ELECTRICITY SECTOR EMISSION CHANGES, RELATIVE TO THE NO CPP ALTERNATIVE BASELINE

[2025–2035]

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
Base Case (CPP)			
2025	−50	−36	−32
2030	−74	−60	−47
2035	−66	−44	−43
2% HRI at $50/kW			
2025	−13	0	−8
2030	−13	−7	−8
2035	−11	−11	−5
4.5% HRI at $50/kW			
2025	−18	4	−11
2030	−14	−7	−8
2035	−7	−1	−1

[67] Office of Management and Budget (OMB), 2003, Circular A–4, *https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf.*

TABLE 7—PROJECTED CO_2, SO_2, AND NO_X ELECTRICITY SECTOR EMISSION CHANGES, RELATIVE TO THE NO CPP ALTERNATIVE BASELINE—Continued

[2025–2035]

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
4.5% HRI at $100/kW			
2025	−30	−3	−18
2030	−27	−15	−15
2035	−22	−16	−11

The emissions changes in these tables do not account for changes in hazardous air pollutants (HAPs) that may occur as a result of this rule. For projected impacts on mercury emissions, please see Chapter 3 of the RIA for this proposed rulemaking.

B. What are the energy impacts?

The proposed actions have energy market implications. Overall, the analysis to support this proposed rule indicates that there are important power sector impacts that are worth noting, although they are relatively small compared to other EPA air regulatory actions for EGUs. The estimated impacts reflect EPA's illustrative analysis of the proposed rule, which applies various levels of heat rate improvements to affected sources in order to ascertain how they might respond, in order to capture the potential systemwide economic and energy impacts of the requirements. States are afforded considerable flexibility in this proposed rule, and thus the impacts could be different, to the extent states make different choices.

Table 8 presents a variety of energy market impacts for 2025, 2030, and 2035 for the four illustrative scenarios, relative to the base case, which includes the CPP.

TABLE 8—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS, RELATIVE TO BASE CASE (CPP)

[Percent change]

	2025 (%)	2030 (%)	2035 (%)
No CPP			
Retail electricity prices	−0.5	−0.4	−0.1
Average price of coal delivered to the power sector	−0.1	−0.2	−0.4
Coal production for power sector use	6.1	9.2	9.5
Price of natural gas delivered to power sector	−1.1	−0.3	0.1
Price of average Henry Hub (spot)	−1.4	−0.8	−0.2
Natural gas use for electricity generation	−1.5	−1.5	−0.9
2% HRI at $50/kW			
Retail electricity prices	−0.3	−0.2	−0.1
Average price of coal delivered to the power sector	0.2	−0.1	−0.4
Coal production for power sector use	5.5	8.0	8.4
Price of natural gas delivered to power sector	−1.1	−0.9	−0.4
Price of average Henry Hub (spot)	−1.4	−1.3	−0.6
Natural gas use for electricity generation	−2.5	−1.7	−1.1
4.5% HRI at $50/kW			
Retail electricity prices	−0.5	−0.4	−0.2
Average price of coal delivered to the power sector	0.7	0.6	0.3
Coal production for power sector use	5.8	8.6	9.5
Price of natural gas delivered to power sector	−1.4	−1.1	−0.7
Price of average Henry Hub (spot)	−1.7	−1.6	−1.0
Natural gas use for electricity generation	−3.4	−2.5	−1.9
4.5% HRI at $100/kW			
Retail electricity prices	−0.2	0.0	0.0
Average price of coal delivered to the power sector	0.5	0.3	−0.1
Coal production for power sector use	4.5	7.1	7.4
Price of natural gas delivered to power sector	−1.3	−1.1	−0.7
Price of average Henry Hub (spot)	−1.6	−1.6	−1.0
Natural gas use for electricity generation	−3.4	−2.3	−1.6

Energy market impacts are discussed more extensively in the RIA found in the rulemaking docket.

C. What are the compliance costs?

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and illustrative scenarios, including the cost of monitoring, reporting, and recordkeeping (MR&R). In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the HRI required by the proposed rule, minus the sectoral cost of complying with the CPP assumed in the base case.

The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the plans that states may ultimately pursue. The illustrative compliance scenarios are designed to reflect, to the extent possible, the scope and nature of the proposed guidelines. However, there is considerable uncertainty with regards to the precise measure that states will adopt to meet the proposed requirements, because there are considerable flexibilities afforded to the states in developing their state plans.

Table 9 presents the annualized compliance costs of the three illustrative policy scenarios and the illustrative No CPP scenario. In this table, and throughout the RIA for this proposed rulemaking, negative costs indicate avoided costs relative to the base case (which includes the CPP), and positive costs indicate an increase in projected compliance costs, relative to the base case. As shown in Table 9, the Agency estimates that there are avoided costs under three out of the four illustrative scenarios. Table 7 shows the same compliance cost information, except relative to the No CPP alternative baseline.

TABLE 9—COMPLIANCE COSTS, RELATIVE TO BASE CASE (CPP)

[Billions of 2016$]

	CPP repeal	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025	(0.7)	0.0	(0.6)	0.5
2030	(0.7)	(0.2)	(1.0)	0.2
2035	(0.4)	0.1	(0.6)	0.5

Notes: Negative costs indicate that, on net, the illustrative scenario avoids costs relative to the base case with the CPP. Compliance costs equal the projected change in total power sector generating costs, plus the costs of monitoring, reporting, and recordkeeping.

TABLE 10—COMPLIANCE COSTS, RELATIVE TO THE NO CPP ALTERNATIVE BASELINE

[Billions of 2016$]

	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025	0.7	0.1	1.3
2030	0.5	(0.2)	0.9
2035	0.5	(0.2)	0.8

Notes: Negative costs indicate that, on net, the illustrative scenario reduces costs relative to the No CPP alternative baseline. Compliance costs equal the projected change in total power sector generating costs, plus the costs of monitoring, reporting, and recordkeeping.

Due to a number of changes in the electricity sector since the CPP was finalized, as documented in the October 2017 RIA conducted for the proposed CPP repeal and Chapter 3 of the RIA for this action, the sector has become less carbon intensive over the past several years, and the trend is projected to continue. These changes and trends are reflected in the modeling used for this analysis. As such, achieving the emissions levels required under CPP requires less effort and expense, relative to a scenario without the CPP, and the estimated compliance costs are significantly lower than what was estimated in the final CPP RIA. More detailed cost estimates are available in the RIA included in the rulemaking docket.

D. What are the economic and employment impacts?

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Market and employment impacts of this proposed action are discussed more extensively in Chapter 5 of the RIA for this proposed rulemaking.

E. What are the benefits of the proposed action?

EPA reports the impact on climate benefits from changes in CO_2 and the impact on health benefits attributable to changes in SO_2, NO_X and $PM_{2.5}$ emissions. EPA refers to the climate benefits as "targeted pollutant benefits" as they reflect the direct benefits of reducing CO_2, and to the ancillary health benefits as "co-benefits" as they are not benefits from reducing the targeted pollutant. To estimate the climate benefits associated with changes in CO_2 emissions, EPA applies a measure of the domestic social cost of carbon (SC–CO_2). The SC–CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. The SC–CO_2 estimates used in the RIA for this proposed rulemaking focus on the direct impacts of climate change that are anticipated to occur within U.S. borders.

The estimated health co-benefits are the monetized value of the forgone human health benefits among populations exposed to changes in $PM_{2.5}$ and ozone. This rule is expected to alter the emissions of SO_2 and NO_X emissions, which will in turn affect the level of $PM_{2.5}$ and ozone in the atmosphere. Using photochemical modeling, EPA predicted the change in the annual average $PM_{2.5}$ and summer season ozone across the U.S. for the years 2025, 2030 and 2035. EPA next quantified the human health impacts and economic value of these changes in air quality using the environmental Benefits Mapping and Analysis Program—Community Edition. EPA quantified effects using concentration-response parameters detailed in the RIA and that are consistent with those employed by the Agency in the PM NAAQS and Ozone NAAQS RIAs (U.S. EPA, 2012; 2015). In these tables, negative values represent forgone benefits and positive benefits represent realized benefits.

Table 11. Forgone Benefits: Estimated Economic Value of Incremental $PM_{2.5}$ and Ozone-Attributable Deaths and Illnesses for Illustrative Scenarios & Three Alternative Approaches to Representing PM Effects in 2025, Relative to Base Case (CPP) (95% Confidence Interval; Billions of 2016\$)[A]

		No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
Ozone benefits summed with PM benefits:													
3% Discount Rate	No-threshold model[B]	-$2.8 (-$0.3 to -$7.7)	*to*	-$6.6 (-$0.6 to -$19)	-$2.6 (-$0.3 to $7)	*to*	-$5.9 (-$0.5 to -$17)	-$2.7 (-$0.3 to -$7.4)	*to*	-$6.2 (-$0.6 to -$18)	-$2.1 (-$0.2 to -$5.9)	*to*	-$4.9 (-$0.2 to -$14)
	Effects above LML[C]	-$1.8 (-$0.1 to -$5.2)	*to*	-$2.4 (-$0.1 to -$7)	-$1.5 (-$0.1 to -$4)	*to*	-$2.2 (-$0.2 to -$6)	-$1.6 ($0.2 to -$4.6)	*to*	-$2.3 (-$0.2 to -$6)	-$1.1 ($.1 to -$3.3)	*to*	-$1.8 (-$0.1 to -$5)
	Effects above NAAQS[D]	-$0.12 (-$0 to -$0.4)	*to*	-$0.4 (-$0 to -$1.3)	-$0.06 (-$0 to -$0.2)	*to*	-$0.21 (-$0 to -$0.6)	-$0.04 ($0 to -$0.1)	*to*	-$0.12 (-$0 to -$0.4)	$0.07 ($0.2 to $0)	*to*	-$0.02 (-$0.1 to $0)
Ozone benefits summed with PM benefits:													
7% Discount Rate	No-threshold model[B]	-$2.6 (-$0.3 to -$7)	*to*	-$6.1 (-$0.6 to -$17)	-$2.4 (-$0.2 to -$6.4)	*to*	-$5.4 (-$0.5 to -$15)	-$2.5 (-$0.2 to -$6.7)	*to*	-$5.7 (-$0.5 to -$16)	-$2 (-$0.1 to -$5.4)	*to*	-$4.4 (-$0.2 to -$13)
	Effects above LML[C]	-$1.7 (-$0 to -$5)	*to*	-$2.2 (-$0.1 to -$6)	-$1.4 (-$0.1 to -$4)	*to*	-$2 (-$0.2 to -$5)	-$1.5 (-$0.1 to -$4.2)	*to*	-$2.1 (-$0.2 to -$6)	-$0.99 ($0.1 to -$3)	*to*	-$1.7 ($0 to -$4.6)
	Effects above NAAQS[D]	-$0.12 (-$0 to -$0.4)	*to*	-$0.43 (-$0 to -$1.3)	-$0.06 (-$0 to -$0.2)	*to*	-$0.21 ($0 to -$0.6)	-$0.04 ($0 to -$0.1)	*to*	-$0.12 (-$0 to -$0.4)	$0.07 ($0.2 to $0)	*to*	$0.02 ($0.1 to $0)

[A] Values rounded to two significant figures

[B] PM effects quantified using a no-threshold model. Low end of range reflects dollar value of effects quantified using concentration-response parameter from Krewski et al. (2009) and Smith et al. (2008) studies; upper end quantified using parameters from Lepeule et al. (2012) and Jerrett et al. (2009).

[C] PM effects quantified at or above the Lowest Measured Level of each long-term epidemiological study. Low end of range reflects dollar value of effects quantified down to LML of Lepeule et al. (2012) study (8 $\mu g/m^3$); high end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 $\mu g/m^3$).

[D] PM effects only quantified at or above the annual mean of 12 to provide insight regarding the fraction of benefits occurring above the NAAQS. Range reflects effects quantified using concentration-response parameters from Smith et al. (2008) study at the low end and Jerrett et al. (2009) at the high end.

Table 12. Forgone Benefits: Estimated Economic Value of Incremental $PM_{2.5}$ and Ozone-Attributable Deaths and Illnesses for Illustrative Scenarios & Three Alternative Approaches to Representing PM Effects in 2030, Relative to Base Case (CPP) (95% Confidence Interval; Billions of 2016$)[A]

		No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
Ozone benefits summed with PM benefits:													
3% Discount Rate	No-threshold model[B]	-$4.9 (-$0.47 to -$13)	*to*	-$11 (-$1 to -$33)	-$4.5 (-$0.4 to -$12)	*to*	-$11 (-$1 to -$30)	-$4.2 (-$0.4 to -$11)	*to*	-$9.8 (-$0.9 to -$28)	-$3.6 (-$0.34 to -$9.7)	*to*	-$8.2 (-$0.8 to -$24)
3% Discount Rate	Effects above LML[C]	-$3.5 (-$0.33 to -$10)	*to*	-$4.2 (-$0.4 to -$11)	-$3.7 (-$0.3 to -$11)	*to*	-$3.8 (-$0.4 to -$10)	-$2.9 (-$0.3 to -$8.3)	*to*	-$3.6 (-$0.4 to -$10)	-$2.3 (-$0.22 to -$6.7)	*to*	-$3 (-$0.3 to -$8)
3% Discount Rate	Effects above NAAQS[D]	-$0.26 ($0 to -$0.75)	*to*	-$0.92 (-$0 to -$2.7)	-$0.43 ($0 to -$1.2)	*to*	-$1.5 (-$0.1 to -$4)	-$0.18 ($0 to -$0.5)	*to*	-$0.63 (-$0.1 to -$1.9)	-$0.13 (-$0 to -$0.4)	*to*	-$0.46 ($0 to -$1.4)
Ozone benefits summed with PM benefits:													
7% Discount Rate	No-threshold model[B]	-$4.5 (-$0.43 to -$12)	*to*	-$10 (-$1 to -$30)	-$4.1 (-$0.4 to -$11)	*to*	-$9.8 (-$0.9 to -$28)	-$3.9 (-$0.4 to -$11)	*to*	-$9 (-$0.8 to -$26)	-$3.3 (-$0.3 to -$8.9)	*to*	-$7.6 (-$0.7 to -$22)
7% Discount Rate	Effects above LML[C]	-$3.3 (-$0.3 to -$9.4)	*to*	-$3.8 (-$0.4 to -$10)	-$3.5 (-$0.3 to -$9.7)	*to*	-$3.5 (-$0.3 to -$10)	-$3.3 (-$0.32 to -$9)	*to*	-$2.7 (-$0.3 to -$7.7)	-$2.2 (-$0.2 to -$6.2)	*to*	-$2.8 (-$0.3 to -$8)
7% Discount Rate	Effects above NAAQS[D]	-$0.26 ($0 to -$0.8)	*to*	-$0.92 (-$0.1 to -$3)	-$0.43 (-$.04 to -$1.2)	*to*	-$1.5 (-$0.1 to -$4)	-$0.18 ($0 to -$0.5)	*to*	-$0.63 (-$0.1 to -$2)	-$0.13 (-$0 to -$0.4)	*to*	-$0.46 (-$0 to -$1.4)

[A] Values rounded to two significant figures

[B] PM effects quantified using a no-threshold model. Low end of range reflects dollar value of effects quantified using concentration-response parameter from Krewski et al. (2009) and Smith et al. (2008) studies; upper end quantified using parameters from Lepeule et al. (2012) and Jerrett et al. (2009).

[C] PM effects quantified at or above the Lowest Measured Level of each long-term epidemiological study. Low end of range reflects dollar value of effects quantified down to LML of Lepeule et al. (2012) study (8 $\mu g/m^3$); high end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 $\mu g/m^3$).

[D] PM effects only quantified at or above the annual mean of 12 to provide insight regarding the fraction of benefits occurring above the NAAQS. Range reflects effects quantified using concentration-response parameters from Smith et al. (2008) study at the low end and Jerrett et al. (2009) at the high end.

Table 13. Forgone Benefits: Estimated Economic Value of Incremental $PM_{2.5}$ and Ozone-Attributable Deaths and Illnesses for Illustrative Scenarios & Three Alternative Approaches to Representing PM Effects in 2035, Relative to Base Case (CPP) (95% Confidence Interval; Billions of 2016$)[A]

		No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
Ozone benefits summed with PM benefits:													
3% Discount Rate	No-threshold model[B]	-$3.8 (-$0.4 to -$10)	*to*	-$8.8 (-$1 to -$25)	-$3 (-$0.29 to -$8.1)	*to*	-$7 (-$0.6 to -$20)	-$4 (-$0.4 to -$11)	*to*	-$9.3 (-$1 to -$27)	-$2.6 (-$0.25 to -$7)	*to*	-$6 (-$1 to -$17)
3% Discount Rate	Effects above LML[C]	-$2.9 (-$0.3 to -$8.4)	*to*	-$3.3 (-$0.3 to -$9)	-$2.4 (-$0.2 to -$7)	*to*	-$2.6 (-$0.3 to -$7)	-$3 (-$0.3 to -$8.6)	*to*	-$3.5 (-$0.3 to -$9)	-$2 (-$0.2 to -$6)	*to*	-$2.3 (-$0.2 to -$6)
3% Discount Rate	Effects above NAAQS[D]	-$0.21 ($0 to -$0.6)	*to*	-$0.73 (-$0.1 to -$2)	-$0.2 ($0 to -$0.6)	*to*	-$0.69 (-$0.1 to -$2)	-$0.24 ($0 to -$0.7)	*to*	-$0.86 (-$0.1 to -$3)	-$0.14 ($0 to -$0.4)	*to*	-$0.48 ($0 to -$1)
Ozone benefits summed with PM benefits:													
7% Discount Rate	No-threshold model[B]	-$3.5 (-$0.3 to -$9)	*to*	-$8.1 (-$1 to -$23)	-$2.7 (-$0.3 to -$8)	*to*	-$6.5 (-$1 to -$19)	-$3.7 (-$0.4 to -$10)	*to*	-$8.6 (-$1 to -$25)	-$2.4 (-$0.2 to -$6)	*to*	-$5.5 (-$1 to -$16)
7% Discount Rate	Effects above LML[C]	-$2.7 (-$0.3 to -$8)	*to*	-$3 (-$0.3 to -$8)	-$2.2 (-$0.2 to -$6.4)	*to*	-$2.4 (-$0.2 to -$7)	-$2.8 (-$0.26 to -$8)	*to*	-$3.2 (-$0.3 to -$9)	-$1.8 (-$0.17 to -$5.3)	*to*	-$2.1 (-$0.2 to -$6)
7% Discount Rate	Effects above NAAQS[D]	-$0.21 ($0 to -$0.6)	*to*	-$0.73 (-$0.1 to -$2)	-$0.2 (-$0 to -$0.6)	*to*	-$0.69 (-$0.1 to -$2)	-$0.24 (-$0 to -$0.7)	*to*	-$0.86 (-$0.1 to -$3)	-$0.14 ($0 to -$0.4)	*to*	-$0.48 ($0 to -$1)

[A] Values rounded to two significant figures

[B] PM effects quantified using a no-threshold model. Low end of range reflects dollar value of effects quantified using concentration-response parameter from Krewski et al. (2009) and Smith et al. (2008) studies; upper end quantified using parameters from Lepeule et al. (2012) and Jerrett et al. (2009).

[C] PM effects quantified at or above the Lowest Measured Level of each long-term epidemiological study. Low end of range reflects dollar value of effects quantified down to LML of Lepeule et al. (2012) study (8 $\mu g/m^3$); high end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 $\mu g/m^3$).

[D] PM effects only quantified at or above the annual mean of 12 to provide insight regarding the fraction of benefits occurring above the NAAQS. Range reflects effects quantified using concentration-response parameters from Smith et al. (2008) study at the low end and Jerrett et al. (2009) at the high end.

Table 14 reports the combined domestic climate benefits and ancillary health co-benefits attributable to changes in SO_2 and NO_X emissions estimated for 3 percent and 7 percent discount rates in the years 2025, 2030 and 2035, in 2016 dollars. This table reports the air pollution effects calculated using $PM_{2.5}$ log-linear no threshold concentration-response functions that quantify risk associated with the full range of $PM_{2.5}$ exposures experienced by the population (U.S. EPA, 2009; U.S. EPA, 2011; NRC, 2002).

In this table, negative benefits indicate forgone benefits, relative to the base case, which includes the CPP. As all benefit estimates in this table are negative values, this indicates that the Agency estimates there to be forgone climate benefits and forgone ancillary health co-benefits under all four illustrative scenarios in the years and discount rates analyzed relative to the base case.

TABLE 14—MONETIZED BENEFITS, RELATIVE TO BASE CASE (CPP)

[billions of 2016$]

	Values calculated using 3% discount rate			Values calculated using 7% discount rate		
	Domestic climate benefits	Ancillary health co-benefits	Total benefits	Domestic climate benefits	Ancillary health co-benefits	Total benefits
No CPP						
2025	(0.3)	(2.8) to (6.6)	(3.2) to (7.0)	(0.1)	(2.6) to (6.1)	(2.7) to (6.1)
2030	(0.5)	(4.9) to (11.4)	(5.4) to (11.9)	(0.1)	(4.5) to (10.5)	(4.6) to (10.6)
2035	(0.5)	(3.8) to (8.8)	(4.3) to (9.3)	(0.1)	(3.5) to (8.1)	(3.6) to (8.2)
2% HRI at $50/kW						
2025	(0.2)	(2.6) to (5.9)	(2.8) to (6.2)	(0.0)	(2.4) to (5.4)	(2.4) to (5.5)
2030	(0.4)	(4.5) to (10.6)	(4.9) to (11.0)	(0.1)	(4.1) to (9.8)	(4.2) to (9.9)
2035	(0.4)	(3.0) to (7.0)	(3.4) to (7.4)	(0.1)	(2.7) to (6.5)	(2.8) to (6.6)
4.5% HRI at $50/kW						
2025	(0.2)	(2.7) to (6.2)	(2.9) to (6.4)	(0.0)	(2.5) to (5.7)	(2.5) to (5.7)
2030	(0.4)	(4.2) to (9.8)	(4.6) to (10.2)	(0.1)	(3.9) to (9.0)	(3.9) to (9.1)
2035	(0.5)	(4.0) to (9.3)	(4.4) to (9.8)	(0.1)	(3.7) to (8.6)	(3.7) to (8.7)
4.5% HRI at $100/kW						
2025	(0.1)	(2.1) to (4.9)	(2.3) to (5.0)	(0.0)	(2.0) to (4.4)	(2.0) to (4.4)
2030	(0.3)	(3.6) to (8.2)	(3.9) to (8.6)	(0.1)	(3.3) to (7.6)	(3.3) to (7.6)
2035	(0.3)	(2.6) to (6.0)	(2.9) to (6.3)	(0.1)	(2.4) to (5.5)	(2.4) to (5.6)

Notes: Negative benefit values indicate forgone benefits relative to the base case, which includes the CPP. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector SO_2, NO_X, and $PM_{2.5}$ emissions and reflect the range based on adult mortality functions (*e.g.,* from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett *et al.* (2009)) using a log-linear no threshold model.

In general, EPA is more confident in the size of the risks estimated from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, EPA is less confident in the risk EPA estimates from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.[68] Furthermore, when setting the 2012 PM NAAQS, the Administrator also acknowledged greater uncertainty in specifying the ''magnitude and significance'' of PM-related health risks at PM concentrations below the NAAQS. As noted in the preamble to the 2012 PM NAAQS final rule, ''EPA concludes that it is not appropriate to place as much confidence in the magnitude and significance of the associations over the lower percentiles of the distribution in each study as at and around the long-term mean concentration.'' (78 FR 3154, January 15, 2013). In general, we are more confident in the size of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

To give readers insight to the distribution of estimated forgone benefits displayed in Table 14, EPA also reports the PM benefits according to alternative concentration cut-points and concentration-response parameters. The percentage of estimated $PM_{2.5}$-related deaths occurring below the lowest measured levels (LML) of the two long-term epidemiological studies EPA uses to estimate risk varies between 16 percent (Krewski et al. 2009) and 79 percent (Lepeule et al. 2012). The percentage of estimated premature deaths occurring above the LML and below the NAAQS ranges between 84 percent (Krewski et al. 2009) and 21 percent (Lepeule et al. 2012). Less than 1% of the estimated premature deaths occur above the annual mean $PM_{2.5}$ NAAQS of 12 μg/m³.

Monetized co-benefits estimates shown here do not include several important benefit categories, such as direct exposure to SO_2, NO_X and hazardous air pollutants including mercury and hydrogen chloride. Although EPA does not have sufficient information or modeling available to provide monetized estimates of changes in exposure to these pollutants for this rule, EPA includes a qualitative assessment of these unquantified benefits in the RIA. For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

X. Statutory and Executive Order Reviews

Additional information about these Statutory and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

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

This proposed action is an economically significant action that was

[68] The **Federal Register** notice for the 2012 PM NAAQS indicates that ''[i]n considering this additional population level information, the Administrator recognizes that, in general, the confidence in the magnitude and significance of an association identified in a study is strongest at and around the long-term mean concentration for the air quality distribution, as this represents the part of the distribution in which the data in any given study are generally most concentrated. She also recognizes that the degree of confidence decreases as one moves towards the lower part of the distribution.''

submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. EPA prepared an analysis of the compliance cost, benefit, and net benefit impacts associated with this action in the analysis years of 2025, 2030, and 2035. This analysis, which is contained in the Regulatory Impact Analysis (RIA) for this proposed rulemaking, is consistent with Executive Order 12866 and is available in the rulemaking docket.

In the RIA for this proposed rulemaking, the Agency presents full benefit cost analysis of four illustrative scenarios. The four illustrative scenarios include a scenario modeling the full repeal of the CPP and three policy scenarios modeling heat rate improvements (HRI) at coal-fired EGUs. Throughout the RIA, these three illustrative policy scenarios are compared against a base case, which includes the CPP. By analyzing against the CPP, the reader can understand the combined impact of a CPP repeal and proposed ACE rule. Inclusion of a No CPP case allows for an understanding of the repeal alone and also allows the reader to evaluate the impact of the policy cases against a No CPP scenario. The RIA assumes a mass-based implementation of the CPP for existing affected sources, and does not assume interstate trading. The three illustrative policy scenarios represent potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs.

The Agency understands that there may be interest in comparing the three illustrative policy scenarios against a scenario that does not include the CPP. For those interested in comparing the potential impacts of policy scenarios in a world without the CPP, results from the three illustrative policy scenarios may be compared against results from the illustrative No CPP scenario. We provide information here on compliance costs, emissions impacts and present value net benefits compared to the No CPP alternative baseline. In addition, the Executive Summary and Chapter 3 of the RIA compares the three illustrative policy scenarios to the scenario of a full CPP repeal. Also, the full suite of model outputs is available in the rulemaking docket.

The three illustrative policy scenarios model different levels and costs of HRIs applied uniformly at all affected coal-fired EGUs in the contiguous U.S. beginning in 2025. EPA has identified the BSER to be HRI. Each of these illustrative scenarios assumes that the affected sources are no longer subject to the state plan requirements of the CPP (*i.e.,* the mass-based requirements assumed for CPP implementation in the base case for the RIA). The cost, suitability, and potential improvement for any of these HRI technologies is dependent on a range of unit-specific factors such as the size, age, fuel use, and the operating and maintenance history of the unit. As such, the HRI potential can vary significantly from unit to unit. EPA does not have sufficient information to assess HRI potential on a unit-by-unit basis.

To avoid the impression that EPA can sufficiently distinguish likely standards of performance across individual affected units and their compliance strategies, this analysis assumes different HRI levels and costs are applied uniformly to affected coal-fired EGUs under each of three illustrative policy scenarios.

The first illustrative scenario, 2 Percent HRI at $50/kW, represents a policy case that reflects modest improvements in HRI absent any revisions to NSR requirements. For many years, industry has indicated to the Agency that many sources have not implemented certain HRI projects because the burdensome costs of NSR cause such projects to not be viable. Thus, absent NSR reform, HRI at affected units might be expected to be modest. Based on numerous studies and statistical analysis, the Agency believes that the HRI potential for coal-fired EGUs will, on average, range from one to three percent at a cost of $30 to $60 per kilowatt (kW) of EGU generating capacity. The Agency believes that this scenario (2 percent HRI at $50/kW) reasonably represents that range of HRI and cost.

The second illustrative scenario, 4.5 Percent HRI at $50/kW, represents a policy case that includes benefits from the proposed revisions to NSR, with the HRI modeled at a low cost. As mentioned earlier, the Agency is proposing revisions to the NSR program that will provide owners and operators of existing EGUs greater ability to make efficiency improvements without triggering provisions of NSR. This scenario is informative in that it represents the ability of all coal-fired EGUs to obtain greater improvements in heat rate because of NSR reform at the $50/kW cost identified earlier. EPA believes this higher heat rate improvement potential is possible because without NSR a greater number of units may have the opportunity to make cost effective heat rate improvements such as turbine upgrades that have the potential to offer greater heat rate improvement opportunities.

The third illustrative scenario, 4.5 Percent HRI at $100/kW, represents a policy case that includes the benefits from the proposed revisions to NSR, with the HRI modeled at a higher cost. This scenario is informative in that it represents the ability of a typical coal-fired EGUs to obtain greater improvements in heat rate because of NSR reform but at a much higher cost ($100/kW) than the $50/kW cost identified earlier. Particularly for lower capacity units or those with limited remaining useful life, this could ultimately translate into HRI projects with costs beyond what most states might determine to be reasonable.

Combined, the 4.5 percent HRI at $50/kW scenario and the 4.5 percent HRI at $100/kW scenario represent a range of potential costs for the proposed policy option that couples HRI with NSR reform. Modeling this at $50/kW and $100/kW provides a sensitivity analysis on the cost of the proposed policy including NSR reform. The $50/kW cost represents an optimistic bounding where NSR reform unleashes significant new opportunity for low-cost heat rate improvements. The $100/kW cost scenario, while informative, represents a high-end bound that could overstate potential because, particularly for lower capacity factor units and those with limited remaining useful life, these would represent project costs that states would likely find to be unreasonable.

We evaluate the potential regulatory impacts of the illustrative No CPP scenario and the three illustrative policy scenarios using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2023–2037 from the perspective of 2016, using both a three percent and seven percent beginning-of-period discount rate. In addition, the Agency presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. In the RIA, the regulatory impacts are evaluated for the specific years of 2025, 2030, and 2035.

The power industry's ''compliance costs'' are represented in this analysis as the change in electric power generation costs between the base case and illustrative scenarios, including the cost of monitoring, reporting, and recordkeeping (MR&R). In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the HRI required by the proposed rule, minus the sectoral cost of complying with the CPP assumed in the base case.

The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the plans that states may ultimately pursue. The illustrative compliance scenarios are designed to reflect, to the extent possible, the scope and nature of the proposed guidelines. However, there is considerable uncertainty with regards to the precise measure that states will adopt to meet the proposed requirements, because there are considerable flexibilities afforded to the states in developing their state plans.

EPA reports the impact on climate benefits from changes in CO_2 and the impact on health benefits attributable to changes in SO_2, NO_X and $PM_{2.5}$ emissions. We refer to the climate benefits as ''targeted pollutant benefits'' as they reflect the direct benefits of reducing CO_2, and to the ancillary health benefits as ''co-benefits'' as they are not benefits from reducing the targeted pollutant. To estimate the climate benefits associated with changes in CO_2 emissions, we apply a measure of the domestic social cost of carbon (SC-CO_2). The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. The SC-CO_2 estimates used in the RIA for this proposed rulemaking focus on the direct impacts of climate change that are anticipated to occur within U.S. borders.

The health co-benefits estimates represent the monetized value of the forgone human health benefits among populations exposed to changes in $PM_{2.5}$ and ozone. This rule is expected to alter the emissions of SO_2, NO_X, and $PM_{2.5}$ emissions, which will in turn affect the level of $PM_{2.5}$ and ozone in the atmosphere. Using photochemical modeling, we predicted the change in the annual average $PM_{2.5}$ and summer season ozone across the U.S. for the years 2025, 2030 and 2035. We next quantified the human health impacts and economic value of these changes in air quality using the environmental Benefits Mapping and Analysis Program—Community Edition. We quantified effects using concentration-response parameters detailed in the RIA and that are consistent with those employed by the Agency in the PM NAAQS and Ozone NAAQS RIAs (U.S. EPA, 2012; 2015).

In general, we are more confident in the size of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.[69]

Furthermore, when setting the 2012 PM NAAQS, the Administrator also acknowledged greater uncertainty in specifying the ''magnitude and significance'' of PM-related health risks at PM concentrations below the NAAQS. As noted in the preamble to the 2012 PM NAAQS final rule, ''EPA concludes that it is not appropriate to place as much confidence in the magnitude and significance of the associations over the lower percentiles of the distribution in each study as at and around the long-term mean concentration.'' (78 FR 3154, 15 January 2013). In general, we are more confident in the size of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

To give readers insight to the distribution of estimated forgone benefits displayed in Table 14, EPA also reports the PM benefits according to alternative concentration cut-points and concentration-response parameters. To give readers insight to the uncertainty in the estimated forgone $PM_{2.5}$ mortality benefits occurring at lower ambient levels, we also report the PM benefits according to alternative concentration cut-points and concentration-response parameters. The percentage of estimated $PM_{2.5}$-related deaths occurring below the lowest measured levels (LML) of the two long-term epidemiological studies we use to estimate risk varies between 16 percent (Krewski et al. 2009) and 79 percent (Lepeule et al. 2012). The percentage of estimated premature deaths occurring above the LML and below the NAAQS ranges between 84 percent (Krewski et al. 2009) and 21 percent (Lepeule et al. 2012). Less than 1% of the estimated premature deaths occur above the annual mean $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$.

Monetized co-benefits estimates shown here do not include several important benefit categories, such as direct exposure to SO_2, NO_X and hazardous air pollutants including mercury and hydrogen chloride. Although we do not have sufficient information or modeling available to provide monetized estimates of changes in exposure to these pollutants for this rule, we include a qualitative assessment of these unquantified benefits in the RIA. For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

In the decision-making process it is useful to consider the change in benefits due to the targeted pollutant relative to the costs. Therefore, in Chapter 6 of the RIA for this proposed rulemaking we present a comparison of the benefits from the targeted pollutant—CO_2—with the compliance costs. Excluded from this comparison are the benefits from changes in $PM_{2.5}$ and ozone concentrations from changes in SO_2, NO_X and $PM_{2.5}$ emissions that are projected to accompany changes in CO_2 emissions.

Table 15 presents the present value (PV) and equivalent annualized value (EAV) of the estimated costs, benefits, and net benefits associated with the targeted pollutant, CO_2, for the timeframe of 2023–2037, relative to the base case, which includes the CPP. The EAV represents an even-flow of figures over the timeframe of 2023–2037 that would yield an equivalent present value. The EAV is identical for each year of the analysis, in contrast to the year-specific estimates presented earlier for the snapshot years of 2025, 2030, and 2035.

In Table 15, and all net benefit tables, negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

[69] The **Federal Register** notice for the 2012 PM NAAQS indicates that ''[i]n considering this additional population level information, the Administrator recognizes that, in general, the confidence in the magnitude and significance of an association identified in a study is strongest at and around the long-term mean concentration for the air quality distribution, as this represents the part of the distribution in which the data in any given study are generally most concentrated. She also recognizes that the degree of confidence decreases as one moves towards the lower part of the distribution.''

TABLE 15—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COSTS, CLIMATE BENEFITS, AND NET BENEFITS ASSOCIATED WITH TARGETED POLLUTANT (CO_2), RELATIVE TO BASE CASE (CPP), 3 AND 7 PERCENT DISCOUNT RATES, 2023–2037

[Billions of 2016$]

	Costs		Domestic climate benefits		Net benefits associated with the targeted pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
Present Value						
No CPP	(5.2)	(3.1)	(3.9)	(0.4)	1.2	2.7
2% HRI at $50/kW	(0.4)	(0.3)	(3.2)	(0.3)	(2.8)	(0.1)
4.5% HRI at $50/kW	(6.4)	(3.7)	(3.2)	(0.3)	3.2	3.4
4.5% HRI at $100/kW	3.0	1.7	(2.4)	(0.2)	(5.4)	(2.0)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(0.3)	(0.0)	0.1	0.3
2% HRI at $50/kW	(0.0)	(0.0)	(0.3)	(0.0)	(0.2)	(0.0)
4.5% HRI at $50/kW	(0.5)	(0.4)	(0.3)	(0.0)	0.3	0.4
4.5% HRI at $100/kW	0.3	0.2	(0.2)	(0.0)	(0.5)	(0.2)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector SO_2 and NO_X emissions.

Table 16 presents the costs, benefits, and net benefits associated with the targeted pollutant for specific years, rather than as a PV or EAV as found in Table 18.

TABLE 16—COMPLIANCE COSTS, CLIMATE BENEFITS, AND NET BENEFITS ASSOCIATED WITH TARGETED POLLUTANT (CO_2), RELATIVE TO BASE CASE (CPP), 3 AND 7 PERCENT DISCOUNT RATES, 2025, 2030, AND 2035

[Billions of 2016$]

	Costs		Domestic climate benefits		Net benefits associated with the targeted pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
No CPP						
2025	(0.7)	(0.7)	(0.3)	(0.1)	0.4	0.7
2030	(0.7)	(0.7)	(0.5)	(0.1)	0.2	0.6
2035	(0.4)	(0.4)	(0.5)	(0.1)	(0.1)	0.3
2% HRI at $50/kW						
2025	0.0	0.0	(0.2)	(0.0)	(0.3)	(0.1)
2030	(0.2)	(0.2)	(0.4)	(0.1)	(0.2)	0.2
2035	0.1	0.1	(0.4)	(0.1)	(0.6)	(0.2)
4.5% HRI at $50/kW						
2025	(0.6)	(0.6)	(0.2)	(0.0)	0.4	0.6
2030	(1.0)	(1.0)	(0.4)	(0.1)	0.5	0.9
2035	(0.6)	(0.6)	(0.5)	(0.1)	0.2	0.5
4.5% HRI at $100/kW						
2025	0.5	0.5	(0.1)	(0.0)	(0.7)	(0.5)
2030	0.2	0.2	(0.3)	(0.1)	(0.5)	(0.2)
2035	0.5	0.5	(0.3)	(0.1)	(0.8)	(0.5)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector SO_2 and NO_X emissions.

Table 17 presents the present value (PV) and equivalent annualized value (EAV) of the estimated costs, benefits, and net benefits associated with the targeted pollutant, CO_2, for the timeframe of 2023–2037, relative to the No CPP alternative baseline.

TABLE 17—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COSTS, CLIMATE BENEFITS, AND NET BENEFITS ASSOCIATED WITH TARGETED POLLUTANT (CO_2), RELATIVE TO THE NO CPP ALTERNATIVE BASELINE, 3 AND 7 PERCENT DISCOUNT RATES, 2023–2037

[Billions of 2016$]

	Costs		Domestic climate benefits		Net benefits associated with the targeted pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
Present Value						
2% HRI at $50/kW	4.8	2.8	0.8	0.1	(4.1)	(2.8)
4.5% HRI at $50/kW	(1.2)	(0.6)	0.7	0.1	2.0	0.7
4.5% HRI at $100/kW	8.2	4.8	1.6	0.2	(6.6)	(4.7)
Equivalent Annualized Value						
2% HRI at $50/kW	0.4	0.3	0.1	0.0	(0.3)	(0.3)
4.5% HRI at $50/kW	(0.1)	(0.1)	0.1	0.0	0.2	0.1
4.5% HRI at $100/kW	0.7	0.5	0.1	0.0	(0.6)	(0.5)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector SO_2 and NO_X emissions.

Table 18 and Table 19 provide the estimated costs, benefits, and net benefits, inclusive of the ancillary health-co benefits and relative to the base case (CPP). Table 18 presents the PV and EAV estimates, and Table 19 presents the estimates for the specific years of 2025, 2030, and 2035.

TABLE 18—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COSTS, TOTAL BENEFITS, AND NET BENEFITS, RELATIVE TO BASE CASE (CPP), 3 AND 7 PERCENT DISCOUNT RATES, 2023–2037

[Billions of 2016$]

	Costs		Benefits		Net benefits	
	3%	7%	3%	7%	3%	7%
Present Value						
No CPP	(5.2)	(3.1)	(37.2) to (81.5)	(17.9) to (41.3)	(32.0) to (76.3)	(14.8) to (38.2)
2% HRI at $50/kW	(0.4)	(0.3)	(32.7) to (72.4)	(15.9) to (36.9)	(32.3) to (72.0)	(15.7) to (36.7)
4.5% HRI at $50/kW	(6.4)	(3.7)	(34.3) to (75.2)	(16.6) to (39.4)	(27.9) to (68.8)	(12.8) to (35.6)
4.5% HRI at $100/kW	3.0	1.7	(27.2) to (60.2)	(13.9) to (31.9)	(30.2) to (63.2)	(15.6) to (33.7)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(3.1) to (6.8)	(2.0) to (4.5)	(2.7) to (6.4)	(1.6) to (4.2)
2% HRI at $50/kW	(0.0)	(0.0)	(2.7) to (6.1)	(1.7) to (4.1)	(2.7) to (6.0)	(1.7) to (4.0)
4.5% HRI at $50/kW	(0.5)	(0.4)	(2.9) to (6.3)	(1.8) to (4.3)	(2.3) to (5.8)	(1.4) to (3.9)
4.5% HRI at $100/kW	0.3	0.2	(2.3) to (5.0)	(1.5) to (3.5)	(2.5) to (5.3)	(1.7) to (3.7)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding. Total benefits include both climate benefits and ancillary health co-benefits. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector SO_2, NO_X and $PM_{2.5}$ emissions and reflect the range based on adult mortality functions (*e.g.,* from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett *et al.* (2009)). PM premature mortality benefits estimated using a log-linear no-threshold model.

TABLE 19—COMPLIANCE COSTS, TOTAL BENEFITS, AND NET BENEFITS, RELATIVE TO BASE CASE (CPP), 3 AND 7 PERCENT DISCOUNT RATES, 2025, 2030, AND 2035

[Billions of 2016$]

	Costs		Benefits		Net benefits	
	3%	7%	3%	7%	3%	7%
No CPP						
2025	(0.7)	(0.7)	(3.2) to (7.0)	(2.7) to (6.1)	(2.4) to (6.2)	(1.9) to (5.4)
2030	(0.7)	(0.7)	(5.4) to (11.9)	(4.6) to (10.6)	(4.7) to (11.2)	(3.8) to (9.8)
2035	(0.4)	(0.4)	(4.3) to (9.3)	(3.6) to (8.2)	(3.9) to (8.9)	(3.2) to (7.8)
2% HRI at $50/kW						
2025	0.0	0.0	(2.8) to (6.2)	(2.4) to (5.5)	(2.8) to (6.2)	(2.4) to (5.5)
2030	(0.2)	(0.2)	(4.9) to (11.0)	(4.2) to (9.9)	(4.7) to (10.8)	(3.9) to (9.7)
2035	0.1	0.1	(3.4) to (7.4)	(2.8) to (6.6)	(3.5) to (7.6)	(3.0) to (6.7)
4.5% HRI at $50/kW						
2025	(0.6)	(0.6)	(2.9) to (6.4)	(2.5) to (5.7)	(2.3) to (5.8)	(1.9) to (5.1)
2030	(1.0)	(1.0)	(4.6) to (10.2)	(3.9) to (9.1)	(3.7) to (9.2)	(3.0) to (8.1)
2035	(0.6)	(0.6)	(4.4) to (9.8)	(3.7) to (8.7)	(3.8) to (9.2)	(3.1) to (8.1)
4.5% HRI at $100/kW						
2025	0.5	0.5	(2.3) to (5.0)	(2.0) to (4.4)	(2.8) to (5.5)	(2.5) to (5.0)
2030	0.2	0.2	(3.9) to (8.6)	(3.3) to (7.6)	(4.1) to (8.7)	(3.5) to (7.8)
2035	0.5	0.5	(2.9) to (6.3)	(2.4) to (5.6)	(3.4) to (6.8)	(2.9) to (6.0)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding. Total benefits include both climate benefits and ancillary health co-benefits. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector SO_2, NO_X and $PM_{2.5}$ emissions and reflect the range based on adult mortality functions (*e.g.,* from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Zanobetti & Schwartz. (2008)). PM premature mortality benefits estimated using a log-linear no-threshold model.

Table 20 provides the estimated costs, benefits, and net benefits, inclusive of the ancillary health-co benefits and relative to the No CPP alternative baseline.

TABLE 20—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COSTS, TOTAL BENEFITS, AND NET BENEFITS, RELATIVE TO THE NO CPP ALTERNATIVE BASELINE, 3 AND 7 PERCENT DISCOUNT RATES, 2023–2037

[Billions of 2016$]

	Costs		Benefits		Net benefits	
	3%	7%	3%	7%	3%	7%
Present Value						
2% HRI at $50/kW	4.8	2.8	4.5 to 9.2	2.0 to 4.3	(0.3) to 4.3	(0.9) to 1.5
4.5% HRI at $50/kW	(1.2)	(0.6)	2.9 to 6.3	1.4 to 1.9	4.1 to 7.5	2.0 to 2.6
4.5% HRI at $100/kW	8.2	4.8	10.0 to 21.3	4.1 to 9.4	1.8 to 13.2	(0.8) to 4.5
Equivalent Annualized Value						
2% HRI at $50/kW	0.4	0.3	0.4 to 0.8	0.2 to 0.5	(0.0) to 0.4	(0.1) to 0.2
4.5% HRI at $50/kW	(0.1)	(0.1)	0.2 to 0.5	0.1 to 0.2	0.3 to 0.6	0.2 to 0.3
4.5% HRI at $100/kW	0.7	0.5	0.8 to 1.8	0.4 to 1.0	0.1 to 1.1	(0.1) to 0.5

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding. Total benefits include both climate benefits and ancillary health co-benefits. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector SO_2, NO_X and $PM_{2.5}$ emissions and reflect the range based on adult mortality functions (*e.g.,* from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett *et al.* (2009)). PM premature mortality benefits estimated using a log-linear no-threshold model.

Throughout the RIA for this proposed rulemaking, EPA examines a number of sources of uncertainty, both quantitatively and qualitatively, on benefits and costs. Some of these elements are evaluated using probabilistic techniques. For other elements, where the underlying likelihoods of certain outcomes are unknown, we use scenario analysis to evaluate their potential effect on the benefits and costs of this proposed rulemaking. We summarize key elements of our analysis of uncertainty here:

- The extent to which all coal-fired EGUs will improve heat rates under this proposal, on average;
- The cost to improve heat rates at all affected coal-fired EGUs nationally;
- Uncertainty in monetizing climate-related benefits; and,
- Uncertainty in the estimated health impacts attributable to changes in particulate matter.

In the RIA for this proposed rulemaking, EPA also summarize other potential sources of benefits and costs that may result from this proposed rule that have not been quantified or monetized.

B. Executive Order 13771: Reducing Regulation and Controlling Regulatory Costs

This action is expected to be an Executive Order 13771 deregulatory action. Details on the estimated cost savings of this proposed rule can be found in the rule's RIA.

C. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that EPA prepared has been assigned EPA ICR number 2503.03. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a state plan to limit CO_2 emissions from existing sources in the power sector. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to 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 Ba.

Respondents/affected entities: 48.

Respondent's obligation to respond: EPA expects state plan submissions from the 43 contiguous states and negative declarations from Vermont, California, Maine, Idaho, and Rhode Island.

Frequency of response: Yearly.

Total estimated burden: 192,640 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $21,500 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to EPA using the docket identified at the beginning of this rule (Comment C–72). You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than October 1, 2018. EPA will respond to any ICR-related comments in the final rule.

D. Regulatory Flexibility Act (RFA)

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The proposed rule will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish emission standards on existing sources, and it is those state requirements that could potentially impact small entities. Our analysis in the accompanying RIA is consistent with the analysis of the analogous situation arising when EPA establishes NAAQS, which do not impose any requirements on regulated entities. As with the description in the RIA, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their state implementation plans. *See American Trucking Assoc.* v. *EPA,* 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

Nevertheless, EPA is aware that there is substantial interest in the proposed rule among small entities (municipal and rural electric cooperatives) and we invite comments on all aspects of the proposal and its impacts, including potential impacts on small entities (Comment C–73).

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate or the private sector in any one year. Specifically, the emission guidelines proposed under CAA section 111(d) do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop state plans. The burden for states to develop state plans in the three-year period following promulgation of the rule was estimated and is listed in Section IX.C above, but this burden is estimated to be below $100 million in any one year. Thus, this proposed rule is not subject to the requirements of section 203 or section 205 of the Unfunded Mandates Reform Act (UMRA).

This proposed rule is also not subject to the requirements of section 203 of UMRA because, as described in 2 U.S.C. 1531–38, it contains no regulatory requirements that might significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

F. Executive Order 13132: Federalism

Under Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs and that is not required by statute unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or EPA consults with state and local officials early in the process of developing the proposed action.

EPA has concluded that this action may have federalism implications because it might impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. The development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with state legislatures as appropriate, and develop a plan submittal.

In the spirit of Executive Order 13132, and consistent with EPA's policy to promote communications between EPA and state and local governments, EPA specifically solicits comment on this proposed action from state and local officials (Comment C–74).

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It would not impose substantial direct compliance costs on tribal governments that have affected EGUs located in their area of Indian country. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs. EPA notes that this proposal does not directly impose specific requirements on EGU sources, including those located in Indian country, but before developing any standards for sources on tribal land, EPA would consult with leaders from affected tribes. This proposed action also will not have substantial direct effects on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the action.

Consistent with EPA Policy on Consultation and Coordination with Indian Tribes, EPA will engage in consultation with tribal officials during the development of this action.

H. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This proposed action is subject to Executive Order 13045 because it is an economically significant regulatory action as defined by Executive Order 12866. The CPP, as discussed in the RIA,[70] was anticipated to reduce emissions of $PM_{2.5}$ and ozone, and some of the benefits of reducing these pollutants would have accrued to children. While the proposed ACE rule does not project to achieve reductions at the level of the CPP, EPA believes that this proposal will achieve CO_2 emission reductions resulting from implementation of these proposed guidelines, as well as ozone and $PM_{2.5}$ emission reductions as a co-benefit, and will further improve children's health as discussed in the RIA.

Moreover, this proposed action does not affect the level of public health and environmental protection already being provided by existing NAAQS, including ozone and $PM_{2.5}$, and other mechanisms in the CAA. This proposed action does not affect applicable local, state, or federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.

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

This proposed action, which is a significant regulatory energy action under Executive Order 12866, is likely to have a significant effect on the supply, distribution, or use of energy. Specifically, EPA estimated in the RIA that the proposed rule could result in up to a 3 percent reduction in natural gas use in the power sector (or more than a 25 MM MCF reduction in production on an annual basis).

The energy impacts EPA estimates from the proposed rule may be under- or over-estimates of the true energy impacts associated with this action. For example, some states are likely to pursue emissions reduction strategies independent of EPA action.

J. National Technology Transfer and Advancement Act (NTTAA)

This proposed rulemaking does not involve technical standards. EPA welcomes comments on this aspect of the proposed rulemaking and specifically invites the public to identify potentially-applicable voluntary consensus standards and to explain why such standards should be used in this action (Comment C–75).

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

EPA believes that this proposed action is unlikely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). The CPP, as discussed in the RIA,[71] was anticipated to reduce emissions of $PM_{2.5}$ and ozone, and some of the benefits of reducing these pollutants would have accrued to minority populations, low-income populations and/or indigenous peoples. While this proposal does not project to achieve reductions at the level of the CPP, EPA believes that this proposal will achieve CO_2 emission reductions resulting from implementation of these proposed guidelines, as well as ozone and $PM_{2.5}$ emission reductions as a co-benefit, and will further improve children's health as discussed in the RIA.

Moreover, this proposed action does not affect the level of public health and environmental protection already being provided by existing NAAQS, including ozone and $PM_{2.5}$, and other mechanisms in the CAA. This proposed action does not affect applicable local, state, or federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.

XI. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, and 307(d)(1)(V) of the CAA, as amended (42 U.S.C. 7411, 7601, 7607(d)(1)(V)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects

40 CFR Part 51

Environmental protection, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 52

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

40 CFR Part 60

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

Dated: August 20, 2018.

Andrew R. Wheeler,

Acting Administrator.

For the reasons stated in the preamble, EPA proposes to amend 40 CFR parts 51, 52, and 60 as set forth below:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 51 continues to read as follows:

[70] See Chapter 5, ''Economic and Employment Impacts'', of the RIA.

[71] See Chapter 5, ''Economic and Employment Impacts,'' of the RIA.

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Subpart I—Review of New Sources and Modifications

■ 2. Add § 51.167 to read as follows:

§ 51.167 Preliminary major NSR applicability test for electric generating units (EGUs).

(a) *What is the purpose of this section?* State Implementation Plans (SIP) may incorporate the requirements in paragraphs (b) through (h) of this section for determining whether a change to an electric generating unit (EGU), as defined in § 51.124(q), is a modification for purposes of major NSR applicability. Deviations from these provisions will be approved only if the State demonstrates that the submitted provisions are at least as stringent in all respects as the corresponding provisions in paragraphs (b) through (h) of this section.

(b) *Am I subject to this section?* You must meet the requirements of this section if your State incorporates these provisions in its SIP, and you own or operate an EGU that is located at a major stationary source, and you plan to make a change to the EGU.

(c) *What happens if a change to my EGU is determined to be a modification according to the procedures of this section?* If the change to your EGU is a modification according to the procedures of this section, you must determine whether the change is a major modification according to the procedures of the major NSR program that applies in the area in which your EGU is located. That is, you must evaluate your modification according to the requirements set out in the applicable regulations approved pursuant to § 51.165 or § 51.166 depending on the regulated NSR pollutants emitted and the attainment status of the area in which your EGU is located for those pollutants. Section 51.165 sets out the requirements for State nonattainment major NSR programs, while § 51.166 sets out the requirements for State PSD programs.

(d) *What is the process for determining if a change to an EGU is a modification?* The two-step process set out in paragraphs (d)(1) and (2) of this section is used to determine (before beginning actual construction) whether a change to an EGU located at a major stationary source is a modification. Regardless of any preconstruction projections, a modification has occurred if a change satisfies both steps in the process.

(1) *Step 1.* Is the change a physical change in, or change in the method of operation of, the EGU? (See paragraph (e) of this section for a list of actions that are not physical or operational changes.) If so, go on to Step 2 (paragraph (d)(2) of this section).

(2) *Step 2.* Will the physical or operational change to the EGU increase the amount of any regulated NSR pollutant emitted into the atmosphere by the source (as determined according to paragraph (f) of this section) or result in the emissions of any regulated NSR pollutant(s) into the atmosphere that the source did not previously emit? If so, the change is a modification.

(e) *What types of actions are not physical changes or changes in the method of operation? (Step 1)* For purposes of this section, a physical change or change in the method of operation shall not include:

(1) Routine maintenance, repair, and replacement;

(2) Use of an alternative fuel or raw material by reason of an order under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(3) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(4) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(5) Use of an alternative fuel or raw material by a stationary source which the source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to § 51.165 or § 51.166, or which:

(i) For purposes of evaluating attainment pollutants, the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21 or under regulations approved pursuant to subpart I of this part; or

(ii) For purposes of evaluating nonattainment pollutants, the source was capable of accommodating before December 21, 1976, unless such change would be prohibited under any federally enforceable permit condition which was established after December 21, 1976 pursuant to 40 CFR 52.21 or under regulations approved pursuant to subpart I of this part;

(6) An increase in the hours of operation or in the production rate, unless such change is prohibited under any federally enforceable permit condition which was established after January 6, 1975 (for purposes of evaluating attainment pollutants) or after December 21, 1976 (for purposes of evaluating nonattainment pollutants) pursuant to 40 CFR 52.21 or regulations approved pursuant to subpart I of this part;

(7) Any change in ownership at a stationary source;

(8) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(i) The State Implementation Plan for the State in which the project is located; and

(ii) Other requirements necessary to attain and maintain the national ambient air quality standard during the project and after it is terminated;

(9) For purposes of evaluating attainment pollutants, the installation or operation of a permanent clean coal technology demonstration project that constitutes repowering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. This exemption shall apply on a pollutant-by-pollutant basis; or

(10) For purposes of evaluating attainment pollutants, the reactivation of a very clean coal-fired EGU.

(f) *How do I determine if there is an emissions increase? (Step 2)* You must determine if the physical or operational change to your EGU increases the amount of any regulated NSR pollutant emitted to the atmosphere using the method in paragraph (f)(1) of this section, subject to the limitations in paragraph (f)(2) of this section. If the physical or operational change to your EGU increases the amount of any regulated NSR pollutant emitted into the atmosphere or results in the emission of any regulated NSR pollutant(s) into the atmosphere that your EGU did not previously emit, the change is a modification as defined in paragraph (h)(2) of this section.

Alternative 1 for paragraph (f)(1):

(1) *Emissions increase test.* For each regulated NSR pollutant for which you have hourly average CEMS or PEMS emissions data with corresponding fuel heat input data, compare the pre-change maximum actual hourly emissions rate in pounds per hour (lb/hr) to a projection of the post-change maximum actual hourly emissions rate in lb/hr, subject to the provisions in paragraphs (f)(1)(i) through (iii) of this section.

(i) *Pre-change emissions.* Determine the pre-change maximum actual hourly emissions rate as follows:

(A) Select a period of 365 consecutive days within the 5-year period immediately preceding when you begin actual construction of the physical or operational change. Compile a data set (for example, in a spreadsheet) with the hourly average CEMS or PEMS (as applicable) measured emissions rates and corresponding heat input data for all of the hours of operation for that 365-day period for the pollutant of interest.

(B) Delete any unacceptable hourly data from this 365-day period in accordance with the data limitations in paragraph (f)(2) of this section.

(C) Extract the hourly data for the 10 percent of the remaining data set corresponding to the highest heat input rates for the selected period. This step may be facilitated by sorting the data set for the remaining operating hours from the lowest to the highest heat input rates.

(D) Calculate the average emissions rate from the extracted (*i.e.,* highest 10 percent heat input rates) data set, using Equation 1:

Equation 1

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

Where:

$\bar{x}$ = average emissions rate, lb/hr;

n = number of emissions rate values; and

x_i = i^{th} emissions rate value, lb/hr.

(E) Calculate the standard deviation of the data set using Equation 2:

Equation 2

$$s = \sqrt{\frac{\sum_{i=1}^{n} X_i^2 - \frac{\left(\sum_{i=1}^{n} X_i\right)^2}{n}}{n-1}}$$

Where:

s = standard deviation of the data set.

(F) Calculate the Upper Tolerance Limit of the data set using Equation 3:

Equation 3

$$UTL = \bar{x} + s * \left[\frac{Z_{1-p} + \sqrt{\left(Z_{1-p}{}^2\right) - \left[1 - \frac{Z_{1-q}{}^2}{2*(n-1)}\right] * \left[Z_{1-p}{}^2 - \frac{Z_{1-q}{}^2}{n}\right]}}{1 - \frac{Z_{1-q}{}^2}{2*(n-1)}}\right]$$

Where:

UTL = Upper Tolerance Limit of the data set;

Z_{1-p} = 3.090, Z score for the 99.9 percentage of interval; and

Z_{1-q} = 2.326, Z score for the 99 percent confidence level.

(G) Use the UTL calculated in paragraph (f)(1)(i)(F) of this section as the pre-change maximum actual hourly emissions rate.

(ii) *Post-change emissions—preconstruction projections.* For each regulated NSR pollutant, you must project the maximum emissions rate that your EGU will actually achieve in any 1 hour in the 5 years following the date the EGU resumes regular operation after the physical or operational change. An emissions increase results from the physical or operational change if this projected maximum actual hourly emissions rate exceeds the pre-change maximum actual hourly emissions rate.

(iii) *Post-change emissions-actually achieved.* Regardless of any preconstruction projections, an emissions increase has occurred if the hourly emissions rate actually achieved in the 5 years after the change exceeds the pre-change maximum actual hourly emissions rate.

Alternative 2 for paragraph (f)(1):

(1) *Emissions increase test.* For each regulated NSR pollutant, compare the pre-change maximum actual hourly emissions rate in pounds per hour (lb/hr) to a projection of the post-change maximum actual hourly emissions rate in lb/hr, subject to the provisions in paragraphs (f)(1)(i) through (iv) of this section.

(i) *Pre-change emissions—general procedures.* The pre-change maximum actual hourly emissions rate for the pollutant is the highest emissions rate (lb/hr) actually achieved by the EGU for 1 hour at any time during the 5-year period immediately preceding when you begin actual construction of the physical or operational change.

(ii) *Pre-change emissions—data sources.* You must determine the highest pre-change hourly emissions rate for each regulated NSR pollutant using the best data available to you. Use the highest available source of data in the following hierarchy, unless your reviewing authority has determined that a data source lower in the hierarchy will provide better data for your EGU:

(A) Continuous emissions monitoring system (CEMS).

(B) Approved predictive emissions monitoring system (PEMS).

(C) Emission tests/emission factor specific to the EGU to be changed.

(D) Material balance calculations.

(E) Published emission factor.

(iii) *Post-change emissions—preconstruction projections.* For each regulated NSR pollutant, you must project the maximum emissions rate that your EGU will actually achieve in any 1 hour in the 5 years following the date the EGU resumes regular operation after the physical or operational change. An emissions increase results from the physical or operational change if this projected maximum actual hourly emissions rate exceeds the pre-change maximum actual hourly emissions rate.

(iv) *Post-change emissions—actually achieved.* Regardless of any preconstruction projections, an emissions increase has occurred if the hourly emissions rate actually achieved in the 5 years after the change exceeds the pre-change maximum actual hourly emissions rate.

Alternative 3 for paragraph (f)(1):

(1) *Emissions increase test.* For each regulated NSR pollutant, compare the maximum achievable hourly emissions rate before the physical or operational change to the maximum achievable hourly emissions rate after the change. Determine these maximum achievable hourly emissions rates according to § 60.14(b) of this chapter. No physical change, or change in the method of operation, at an existing EGU shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any regulated NSR pollutant above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(2) *Data limitations for maximum emissions rates.* For purposes of determining pre-change and post-change maximum emissions rates under paragraph (f)(1) of this section, the following limitations apply to the types of data that you may use:

(i) *Data limitations for Alternatives 1–2.* (A) You must not use emissions rate data associated with startups, shutdowns, or malfunctions of your EGU, as defined by applicable regulation(s) or permit term(s), or malfunctions of an associated air pollution control device. A malfunction means any sudden, infrequent, and not reasonably preventable failure of the EGU or the air pollution control equipment to operate in a normal or usual manner.

(B) You must not use continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) data recorded during monitoring system out-of-control periods. Out-of-control periods include those during which the monitoring system fails to meet quality assurance criteria (for example, periods of system breakdown, repair, calibration checks, or zero and span adjustments) established by regulation, by permit, or in an approved quality assurance plan.

(C) You must not use emissions rate data from periods of noncompliance when your EGU was operating above an emission limitation that was legally enforceable at the time the data were collected.

(D) You must not use data from any period for which the information is inadequate for determining emissions rates, including information related to the limitations in paragraphs (f)(2)(i)(A) through (C) of this section.

(ii) *Data limitations for Alternative 3.* (A) You must not use emissions rate data associated with startups, shutdowns, or malfunctions of your EGU, as defined by applicable regulation(s) or permit term(s), or malfunctions of an associated air pollution control device. A malfunction means any sudden, infrequent, and not reasonably preventable failure of the EGU or the air pollution control equipment to operate in a normal or usual manner.

(B) You must not use continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) data recorded during monitoring system out-of-control periods. Out-of-control periods include those during which the monitoring system fails to meet quality assurance criteria (for example, periods of system breakdown, repair, calibration checks, or zero and span adjustments) established by regulation, by permit, or in an approved quality assurance plan.

(C) You must not use data from any period for which the information is inadequate for determining emissions rates, including information related to the limitations in paragraphs (f)(2)(ii)(A) and (B) of this section.

(g) *What are my requirements for recordkeeping?* You must maintain a file of all information related to determinations that you make under this section of whether a change to an EGU is a modification, subject to the following provisions:

(1) The file must include, but is not limited to, the following information recorded in permanent form suitable for inspection:

(i) Continuous monitoring system, monitoring device, and performance testing measurements;

(ii) All continuous monitoring system performance evaluations;

(iii) All continuous monitoring system or monitoring device calibration checks;

(iv) All adjustments and maintenance performed on these systems or devices; and

(v) All other information relevant to any determination made under this section of whether a change to an EGU is a modification.

(2) You must retain the file until the later of:

(i) The date 5 years following the date the EGU resumes regular operation after the physical or operational change; and

(ii) The date 5 years following the date of such measurements, maintenance, reports, and records.

(h) *What definitions apply under this section?* The definitions of terms in § 51.124(q) apply. Terms used in this section have the meaning accorded them under § 51.165(a)(1) or § 51.166(b), as appropriate. Terms not defined here or in § 51.165(a)(1) or § 51.166(b) (as appropriate) have the meaning accorded them under the applicable requirements of the Clean Air Act.

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 3. The authority citation for part 52 continues to read as follows:

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

Subpart A—General Provisions

■ 4. Add § 52.25 to read as follows:

§ 52.25 Preliminary major NSR applicability test for electric generating units (EGUs).

(a) *What is the purpose of this section?* The provisions of this section are applicable to any State implementation plan which has been disapproved with respect to prevention of significant deterioration of air quality in any portion of any State where the existing air quality is better than the national ambient air quality standards. Specific disapprovals are listed where applicable, in subparts B through DDD and FFF of this part. The provisions of this section have been incorporated by reference into the applicable implementation plans for various States, as provided in subparts B through DDD and FFF of this part. Where this section is so incorporated, the provisions shall also be applicable to all lands owned by the Federal Government and Indian Reservations located in such State. No disapproval with respect to a State's failure to prevent significant deterioration of air quality shall invalidate or otherwise affect the obligations of States, emission sources, or other persons with respect to all portions of plans approved or promulgated under this part.

(b) *Am I subject to this section?* You must meet the requirements of this section if you own or operate an EGU that is located at a major stationary source, and you plan to make a change to the EGU.

(c) *What happens if a change to my EGU is determined to be a modification according to the procedures of this section?* If the change to your electric generating unit (EGU), as defined in § 51.124(q) of this chapter, is a modification according to the procedures of this section, you must determine whether the change is a major modification according to the procedures of the major NSR program that applies in the area in which your EGU is located. That is, you must evaluate your modification according to the requirements set out in the applicable regulations approved pursuant to § 52.21.

(d) *What is the process for determining if a change to an EGU is a modification?* The two-step process set out in paragraphs (d)(1) and (2) of this section is used to determine (before beginning actual construction) whether a change to an EGU located at a major stationary source is a modification. Regardless of any preconstruction projections, a modification has occurred if a change satisfies both steps in the process.

(1) *Step 1.* Is the change a physical change in, or change in the method of operation of, the EGU? (See paragraph (e) of this section for a list of actions that are not physical or operational changes.) If so, go on to Step 2 (paragraph (d)(2) of this section).

(2) *Step 2.* Will the physical or operational change to the EGU increase the amount of any regulated NSR pollutant emitted into the atmosphere by the source (as determined according to paragraph (f) of this section) or result in the emissions of any regulated NSR pollutant(s) into the atmosphere that the source did not previously emit? If so, the change is a modification.

(e) *What types of actions are not physical changes or changes in the method of operation? (Step 1)* For purposes of this section, a physical change or change in the method of operation shall not include:

(1) Routine maintenance, repair, and replacement;

(2) Use of an alternative fuel or raw material by reason of an order under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(3) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(4) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(5) Use of an alternative fuel or raw material by a stationary source which the source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to § 51.166 of this chapter, or which the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR part 51, subpart I; or

(6) An increase in the hours of operation or in the production rate, unless such change is prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21 or regulations approved pursuant to 40 CFR part 51, subpart I;

(7) Any change in ownership at a stationary source;

(8) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(i) The State Implementation Plan for the State in which the project is located; and

(ii) Other requirements necessary to attain and maintain the national ambient air quality standard during the project and after it is terminated;

(9) For purposes of evaluating attainment pollutants, the installation or operation of a permanent clean coal technology demonstration project that constitutes repowering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. This exemption shall apply on a pollutant-by-pollutant basis; or

(10) For purposes of evaluating attainment pollutants, the reactivation of a very clean coal-fired EGU.

(f) *How do I determine if there is an emissions increase? (Step 2)* You must determine if the physical or operational change to your EGU increases the amount of any regulated NSR pollutant emitted to the atmosphere using the method in paragraph (f)(1) of this section, subject to the limitations in paragraph (f)(2) of this section. If the physical or operational change to your EGU increases the amount of any regulated NSR pollutant emitted into the atmosphere or results in the emission of any regulated NSR pollutant(s) into the atmosphere that your EGU did not previously emit, the change is a modification as defined in paragraph (h)(2) of this section.

Alternative 1 for paragraph (f)(1):

(1) *Emissions increase test.* For each regulated NSR pollutant for which you have hourly average CEMS or PEMS emissions data with corresponding fuel heat input data, compare the pre-change maximum actual hourly emissions rate in pounds per hour (lb/hr) to a projection of the post-change maximum actual hourly emissions rate in lb/hr, subject to the provisions in paragraphs (f)(1)(i) through (iii) of this section.

(i) *Pre-change emissions.* Determine the pre-change maximum actual hourly emissions rate as follows:

(A) Select a period of 365 consecutive days within the 5-year period immediately preceding when you begin actual construction of the physical or operational change. Compile a data set (for example, in a spreadsheet) with the hourly average CEMS or PEMS (as applicable) measured emissions rates and corresponding heat input data for all of the hours of operation for that 365-day period for the pollutant of interest.

(B) Delete any unacceptable hourly data from this 365-day period in accordance with the data limitations in paragraph (f)(2) of this section.

(C) Extract the hourly data for the 10 percent of the remaining data set corresponding to the highest heat input rates for the selected period. This step may be facilitated by sorting the data set for the remaining operating hours from the lowest to the highest heat input rates.

(D) Calculate the average emissions rate from the extracted (*i.e.,* highest 10 percent heat input rates) data set, using Equation 1:

Equation 1

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

Where:
$\bar{x}$ = average emissions rate, lb/hr;
n = number of emissions rate values; and
x_i = i^{th} emissions rate value, lb/hr.

(E) Calculate the standard deviation of the data set using Equation 2:

Equation 2

$$s = \sqrt{\frac{\sum_{i=1}^{n} X_i^2 - \frac{\left(\sum_{i=1}^{n} X_i\right)^2}{n}}{n-1}}$$

Where:
s = standard deviation of the data set.

(F) Calculate the Upper Tolerance Limit of the data set using Equation 3:

Equation 3

$$UTL = \bar{x} + s * \left[\frac{Z_{1-p} + \sqrt{\left(Z_{1-p}{}^2\right) - \left[1 - \frac{Z_{1-q}{}^2}{2*(n-1)}\right] * \left[Z_{1-p}{}^2 - \frac{Z_{1-q}{}^2}{n}\right]}}{1 - \frac{Z_{1-q}{}^2}{2*(n-1)}}\right]$$

Where:
UTL = Upper Tolerance Limit of the data set;
Z_{1-p} = 3.090, Z score for the 99.9 percentage of interval; and
Z_{1-q} = 2.326, Z score for the 99 percent confidence level.

(G) Use the UTL calculated in paragraph (f)(1)(i)(F) of this section as the pre-change maximum actual hourly emissions rate.

(ii) *Post-change emissions—preconstruction projections.* For each regulated NSR pollutant, you must project the maximum emissions rate that your EGU will actually achieve in any 1 hour in the 5 years following the date the EGU resumes regular operation after the physical or operational change. An emissions increase results from the physical or operational change if this projected maximum actual hourly emissions rate exceeds the pre-change maximum actual hourly emissions rate.

(iii) *Post-change emissions—actually achieved.* Regardless of any preconstruction projections, an emissions increase has occurred if the hourly emissions rate actually achieved in the 5 years after the change exceeds the pre-change maximum actual hourly emissions rate.

Alternative 2 for paragraph (f)(1):

(1) *Emissions increase test.* For each regulated NSR pollutant, compare the pre-change maximum actual hourly emissions rate in pounds per hour (lb/hr) to a projection of the post-change maximum actual hourly emissions rate in lb/hr, subject to the provisions in paragraphs (f)(1)(i) through (iv) of this section.

(i) *Pre-change emissions—general procedures.* The pre-change maximum actual hourly emissions rate for the pollutant is the highest emissions rate (lb/hr) actually achieved by the EGU for 1 hour at any time during the 5-year period immediately preceding when you begin actual construction of the physical or operational change.

(ii) *Pre-change emissions—data sources.* You must determine the highest pre-change hourly emissions rate for each regulated NSR pollutant using the best data available to you. Use the highest available source of data in the following hierarchy, unless your reviewing authority has determined that a data source lower in the hierarchy will provide better data for your EGU:

(A) Continuous emissions monitoring system (CEMS).

(B) Approved predictive emissions monitoring system (PEMS).

(C) Emission tests/emission factor specific to the EGU to be changed.

(D) Material balance calculations.

(E) Published emission factor.

(iii) *Post-change emissions—preconstruction projections.* For each regulated NSR pollutant, you must project the maximum emissions rate that your EGU will actually achieve in any 1 hour in the 5 years following the date the EGU resumes regular operation after the physical or operational change. An emissions increase results from the physical or operational change if this projected maximum actual hourly emissions rate exceeds the pre-change maximum actual hourly emissions rate.

(iv) *Post-change emissions—actually achieved.* Regardless of any preconstruction projections, an emissions increase has occurred if the hourly emissions rate actually achieved in the 5 years after the change exceeds the pre-change maximum actual hourly emissions rate.

Alternative 3 for paragraph (f)(1):

(1) *Emissions increase test.* For each regulated NSR pollutant, compare the maximum achievable hourly emissions rate before the physical or operational change to the maximum achievable hourly emissions rate after the change. Determine these maximum achievable

hourly emissions rates according to § 60.14(b) of this chapter. No physical change, or change in the method of operation, at an existing EGU shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any regulated NSR pollutant above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(2) *Data limitations for maximum emissions rates.* For purposes of determining pre-change and post-change maximum emissions rates under paragraph (f)(1) of this section, the following limitations apply to the types of data that you may use:

(i) *Data limitations for Alternatives 1–2.* (A) You must not use emissions rate data associated with startups, shutdowns, or malfunctions of your EGU, as defined by applicable regulation(s) or permit term(s), or malfunctions of an associated air pollution control device. A malfunction means any sudden, infrequent, and not reasonably preventable failure of the EGU or the air pollution control equipment to operate in a normal or usual manner.

(B) You must not use continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) data recorded during monitoring system out-of-control periods. Out-of-control periods include those during which the monitoring system fails to meet quality assurance criteria (for example, periods of system breakdown, repair, calibration checks, or zero and span adjustments) established by regulation, by permit, or in an approved quality assurance plan.

(C) You must not use emissions rate data from periods of noncompliance when your EGU was operating above an emission limitation that was legally enforceable at the time the data were collected.

(D) You must not use data from any period for which the information is inadequate for determining emissions rates, including information related to the limitations in paragraphs (f)(2)(i)(A) through (C) of this section.

(ii) *Data limitations for Alternative 3.* (A) You must not use emissions rate data associated with startups, shutdowns, or malfunctions of your EGU, as defined by applicable regulation(s) or permit term(s), or malfunctions of an associated air pollution control device. A malfunction means any sudden, infrequent, and not reasonably preventable failure of the EGU or the air pollution control equipment to operate in a normal or usual manner.

(B) You must not use continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) data recorded during monitoring system out-of-control periods. Out-of-control periods include those during which the monitoring system fails to meet quality assurance criteria (for example, periods of system breakdown, repair, calibration checks, or zero and span adjustments) established by regulation, by permit, or in an approved quality assurance plan.

(C) You must not use data from any period for which the information is inadequate for determining emissions rates, including information related to the limitations in paragraphs (f)(2)(ii)(A) and (B) of this section.

(g) *What are my requirements for recordkeeping?* You must maintain a file of all information related to determinations that you make under this section of whether a change to an EGU is a modification, subject to the following provisions:

(1) The file must include, but is not limited to, the following information recorded in permanent form suitable for inspection:

(i) Continuous monitoring system, monitoring device, and performance testing measurements;

(ii) All continuous monitoring system performance evaluations;

(iii) All continuous monitoring system or monitoring device calibration checks;

(iv) All adjustments and maintenance performed on these systems or devices; and

(v) All other information relevant to any determination made under this section of whether a change to an EGU is a modification.

(2) You must retain the file until the later of:

(i) The date 5 years following the date the EGU resumes regular operation after the physical or operational change; and

(ii) The date 5 years following the date of such measurements, maintenance, reports, and records.

(h) *What definitions apply under this section?* The definitions of terms in § 51.124(q) of this chapter apply. Terms used in this section have the meaning accorded them under § 52.21. Terms not defined here or in § 52.21 have the meaning accorded them under the applicable requirements of the Clean Air Act.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

■ 6. Add subpart Ba to read as follows:

Subpart Ba—Adoption and Submittal of State Plans for Designated Facilities

Sec.

Subpart Ba—Adoption and Submittal of State Plans for Designated Facilities

§ 60.20a Applicability.

(a) The provisions of this subpart apply to States upon publication of a final emission guideline under § 60.22a(a), if such final guideline is published after [date of publication of final rule in the **Federal Register**].

(1) Each emission guideline promulgated under this part is subject to the requirements of this subpart, except that each emission guideline may include specific provisions in addition to or that supersede requirements of this subpart. Each emission guideline must identify explicitly any provision of this subpart that is superseded.

(2) Terms used throughout this part are defined in § 60.21a or in the Clean Air Act (Act) as amended in 1990, except that emission guidelines promulgated as individual subparts of this part may include specific definitions in addition to or that supersede definitions in § 60.21a.

(b) No standard of performance or other requirement established under this part shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 112, Part C or D, or any other authority of the Act), or a standard issued under State authority. The Administrator may specify in a specific standard under this part that facilities subject to other provisions under the Act need only comply with the provisions of that standard.

§ 60.21a Definitions.

Terms used but not defined in this subpart shall have the meaning given them in the Act and in subpart A:

(a) *Designated pollutant* means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b) of the Act.

(b) *Designated facility* means any existing facility (see § 60.2a(aa)) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2a(e)).

(c) *Plan* means a plan under section 111(d) of the Act which establishes standards of performance for designated pollutants from designated facilities and provides for the implementation and enforcement of such standards of performance.

(d) *Applicable plan* means the plan, or most recent revision thereof, which has been approved under § 60.27a(b) or promulgated under § 60.27a(d).

(e) *Emission guideline* means a final guideline document published under § 60.22a(a), which includes information on the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator has determined has been adequately demonstrated for designated facilities.

(f) *Standard of performance* means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated, including, but not limited to,a legally enforceable regulation setting forth an allowable rate or limit of emissions into the atmosphere, or prescribing a design, equipment, work practice, or operational standard, or combination thereof.

(g) *Compliance schedule* means a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific standards of performance contained in a plan or with any increments of progress to achieve such compliance.

(h) *Increments of progress* means steps to achieve compliance which must be taken by an owner or operator of a designated facility, including:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification;

(3) Initiation of on-site construction or installation of emission control equipment or process change;

(4) Completion of on-site construction or installation of emission control equipment or process change; and

(5) Final compliance.

(i) *Region* means an air quality control region designated under section 107 of the Act and described in part 81 of this chapter.

(j) *Local agency* means any local governmental agency.

§ 60.22a Publication of emission guidelines.

(a) Concurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft emission guideline containing information pertinent to control of the designated pollutant from designated facilities. Notice of the availability of the draft emission guideline will be published in the **Federal Register** and public comments on its contents will be invited. After consideration of public comments, a final emission guideline will be published and notice of its availability will be published in the **Federal Register**.

(b) Emission guidelines published under this section will provide information for the development of State plans, such as:

(1) A description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.

(2) Information on the degree of emission reduction which is achievable with each system, together with information on the costs, nonair quality health environmental effects, and energy requirements of applying each system to designated facilities.

(3) Incremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.

(4) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such achieving reduction and any nonair quality health and environmental impact and energy requirements) that has been adequately demonstrated for designated facilities, and the time within which compliance with standards of performance can be achieved. The Administrator may specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

(5) Such other available information as the Administrator determines may contribute to the formulation of State plans.

§ 60.23a Adoption and submittal of State plans; public hearings.

(a)(1) Unless otherwise specified in the applicable subpart, within three years after notice of the availability of a final emission guideline is published under § 60.22a(a), each State shall adopt and submit to the Administrator, in accordance with § 60.4, a plan for the control of the designated pollutant to which the emission guideline applies.

(2) At any time, each State may adopt and submit to the Administrator any plan revision necessary to meet the requirements of this subpart or an applicable subpart of this part.

(b) If no designated facility is located within a State, the State shall submit a letter of certification to that effect to the Administrator within the time specified in paragraph (a) of this section. Such certification shall exempt the State from the requirements of this subpart for that designated pollutant.

(c) The State shall, prior to the adoption of any plan or revision thereof, conduct one or more public hearings within the State on such plan or plan revision.

(d) Any hearing required by paragraph (c) of this section shall be held only after reasonable notice. Notice shall be given at least 30 days prior to the date of such hearing and shall include:

(1) Notification to the public by prominently advertising the date, time, and place of such hearing in each region affected. This requirement may be satisfied by advertisement on the internet;

(2) Availability, at the time of public announcement, of each proposed plan or revision thereof for public inspection in at least one location in each region to which it will apply. This requirement may be satisfied by posting each proposed plan or revision on the internet;

(3) Notification to the Administrator;

(4) Notification to each local air pollution control agency in each region to which the plan or revision will apply; and

(5) In the case of an interstate region, notification to any other State included in the region.

(e) The State may cancel the public hearing through a method it identifies if no request for a public hearing is received during the 30 day notification period under subsection (d) and the original notice announcing the 30 day notification period states that if no request for a public hearing is received the hearing will be cancelled; identifies the method and time for announcing that the hearing has been cancelled; and provides a contact phone number for the public to call to find out if the hearing has been cancelled.

(f) The State shall prepare and retain, for a minimum of 2 years, a record of each hearing for inspection by any interested party. The record shall contain, as a minimum, a list of witnesses together with the text of each presentation.

(g) The State shall submit with the plan or revision:

(1) Certification that each hearing required by paragraph (c) of this section was held in accordance with the notice required by paragraph (d) of this section; and

(2) A list of witnesses and their organizational affiliations, if any, appearing at the hearing and a brief written summary of each presentation or written submission.

(h) Upon written application by a State agency (through the appropriate Regional Office), the Administrator may approve State procedures designed to insure public participation in the matters for which hearings are required and public notification of the opportunity to participate if, in the judgment of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and participation of the public. The Administrator may impose such conditions on his approval as he deems necessary. Procedures approved under this section shall be deemed to satisfy the requirements of this subpart regarding procedures for public hearings.

§ 60.24a Standards of performance and compliance schedules.

(a) Each plan shall include standards of performance and compliance schedules.

(b) Standards of performance shall either be based on allowable rate or limit of emissions, except when it is not feasible to prescribe or enforce a standard of performance. The EPA shall identify such cases in the emission guidelines issued under § 60.22a. Where standards of performance prescribing design, equipment, work practice, or operational standard, or combination thereof are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such standards, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

(1) Test methods and procedures for determining compliance with the standards of performance shall be specified in the plan. Methods other than those specified in appendix A to this part or an applicable subpart of this part may be specified in the plan if shown to be equivalent or alternative methods as defined in § 60.2(t) and (u).

(2) Standards of performance shall apply to all designated facilities within the State. A plan may contain standards of performance adopted by local jurisdictions provided that the standards are enforceable by the State.

(c) Except as provided in paragraph (e) of this section, standards of performance shall be no less stringent than the corresponding emission guideline(s) specified in subpart C of this part, and final compliance shall be required as expeditiously as practicable, but no later than the compliance times specified in an applicable subpart of this part.

(d)(1) Any compliance schedule extending more than 24 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Unless otherwise specified in the applicable subpart, increments of progress must include, where practicable, each increment of progress specified in § 60.21a(h) and must include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance.

(2) A plan may provide that compliance schedules for individual sources or categories of sources will be formulated after plan submittal. Any such schedule shall be the subject of a public hearing held according to § 60.23a and shall be submitted to the Administrator within 60 days after the date of adoption of the schedule but in no case later than the date prescribed for submittal of the first semiannual report required by § 60.25a(e).

(e) In applying a standard of performance to a particular source, the State may take into consideration factors, such as the remaining useful life of such source, provided that the State demonstrates with respect to each such facility (or class of such facilities):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

(f) Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing:

(1) Standards of performance more stringent than emission guidelines specified in subpart C of this part or in applicable emission guidelines; or

(2) Compliance schedules requiring final compliance at earlier times than those specified in subpart C or in applicable emission guidelines.

§ 60.25a Emission inventories, source surveillance, reports.

(a) Each plan shall include an inventory of all designated facilities, including emission data for the designated pollutants and information related to emissions as specified in appendix D to this part. Such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable standards of performance. As used in this subpart, ''correlated'' means presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions allowable under applicable standards of performance.

(b) Each plan shall provide for monitoring the status of compliance with applicable standards of performance. Each plan shall, as a minimum, provide for:

(1) Legally enforceable procedures for requiring owners or operators of designated facilities to maintain records and periodically report to the State information on the nature and amount of emissions from such facilities, and/or such other information as may be necessary to enable the State to determine whether such facilities are in compliance with applicable portions of the plan. Submission of electronic documents shall comply with the requirements of 40 CFR part 3—(Electronic reporting).

(2) Periodic inspection and, when applicable, testing of designated facilities.

(c) Each plan shall provide that information obtained by the State under paragraph (b) of this section shall be correlated with applicable standards of performance (see § 60.25a(a)) and made available to the general public.

(d) The provisions referred to in paragraphs (b) and (c) of this section shall be specifically identified. Copies of such provisions shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates:

(i) That the provisions are applicable to the designated pollutant(s) for which the plan is submitted, and

(ii) That the requirements of § 60.26a are met.

(e) The State shall submit reports on progress in plan enforcement to the Administrator on an annual (calendar year) basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. Information required under this paragraph must be included in the annual report required by § 51.321 of this chapter.

(f) Each progress report shall include:

(1) Enforcement actions initiated against designated facilities during the reporting period, under any standard of performance or compliance schedule of the plan.

(2) Identification of the achievement of any increment of progress required by the applicable plan during the reporting period.

(3) Identification of designated facilities that have ceased operation during the reporting period.

(4) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of plan development but began operation during the reporting period.

(5) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(6) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

§ 60.26a Legal authority.

(a) Each plan shall show that the State has legal authority to carry out the plan, including authority to:

(1) Adopt standards of performance and compliance schedules applicable to designated facilities.

(2) Enforce applicable laws, regulations, standards, and compliance schedules, and seek injunctive relief.

(3) Obtain information necessary to determine whether designated facilities are in compliance with applicable laws, regulations, standards, and compliance schedules, including authority to require recordkeeping and to make inspections and conduct tests of designated facilities.

(4) Require owners or operators of designated facilities to install, maintain, and use emission monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such facilities; also authority for the State to make such data available to the public as reported and as correlated with applicable standards of performance.

(b) The provisions of law or regulations which the State determines provide the authorities required by this section shall be specifically identified. Copies of such laws or regulations shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates that the laws or regulations are applicable to the designated pollutant(s) for which the plan is submitted.

(c) The plan shall show that the legal authorities specified in this section are available to the State at the time of submission of the plan. Legal authority adequate to meet the requirements of paragraphs (a)(3) and (4) of this section may be delegated to the State under section 114 of the Act.

(d) A State governmental agency other than the State air pollution control agency may be assigned responsibility for carrying out a portion of a plan if the plan demonstrates to the Administrator's satisfaction that the State governmental agency has the legal authority necessary to carry out that portion of the plan.

(e) The State may authorize a local agency to carry out a plan, or portion thereof, within the local agency's jurisdiction if the plan demonstrates to the Administrator's satisfaction that the local agency has the legal authority necessary to implement the plan or portion thereof, and that the authorization does not relieve the State of responsibility under the Act for carrying out the plan or portion thereof.

§ 60.27a Actions by the Administrator.

(a) The Administrator may, whenever he determines necessary, shorten the period for submission of any plan or plan revision or portion thereof.

(b) After determination that a plan or plan revision is complete per the requirements of paragraph (g) of this section, the Administrator will take action on the plan or revision. The Administrator will, within twelve months of finding that a plan or plan revision is complete, approve or disapprove such plan or revision or each portion thereof.

(c) The Administrator will propose to promulgate, through notice and comment rulemaking, a federal plan, or portion thereof, for a State if:

(1) The Administrator finds that a State fails to submit a required complete plan or complete plan revision within the time prescribed; or

(2) The Administrator disapproves the required State plan or plan revision or any portion thereof, as unsatisfactory because the applicable requirements of this subpart or an applicable subpart under this part have not been met.

(d) The Administrator will, at any time within two years after the finding of failure to submit a complete plan or disapproval described under paragraph (c) of this section, promulgate a final federal plan unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator determines to be approvable.

(e)(1) Except as provided in paragraph (e)(2) of this section, a federal plan promulgated by the Administrator under this section will prescribe standards of performance of the same stringency as the corresponding emission guideline(s) specified in the final emission guideline published under § 60.22a(a) and will require compliance with such standards as expeditiously as practicable but no later than the times specified in the emission guideline.

(2) Upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply, the Administrator may provide for the application of less stringent standards of performance or longer compliance schedules than those otherwise required by this section in accordance with the criteria specified in § 60.24a(f).

(f) Prior to promulgation of a federal plan under paragraph (d) of this section, the Administrator will provide the opportunity for at least one public hearing in either:

(1) Each State that failed to hold a public hearing as required by § 60.23a(c); or

(2) Washington, DC or an alternate location specified in the **Federal Register**.

(g) Each plan or plan revision that is submitted to the Administrator shall be reviewed for completeness as described in paragraphs (g)(1) through (g)(3) of this section.

(1) *General.* Within 60 days of the Administrator's receipt of a state submission, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria for completeness have been met. Any plan or plan revision that a State submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. Where the Administrator determines that a plan submission does not meet the minimum criteria of this paragraph, the State will be treated as not having made the submission and the requirements of this section regarding promulgation of a federal plan shall apply.

(2) *Administrative criteria.* In order to be deemed complete, a State plan must contain each of the following administrative criteria:

(i) A formal letter of submittal from the Governor or her designee requesting EPA approval of the plan or revision thereof;

(ii) Evidence that the State has adopted the plan in the state code or body of regulations. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date;

(iii) Evidence that the State has the necessary legal authority under state law to adopt and implement the plan;

(iv) A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan. The submittal must be a copy of the official state regulation or document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the State. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The State's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submittal must indicate the changes made (for example, by redline/strikethrough) to the approved plan;

(v) Evidence that the State followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption and issuance of the plan;

(vi) Evidence that public notice was given of the proposed change with procedures consistent with the requirements of § 60.23, including the date of publication of such notice;

(vii) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the State's laws and constitution, if applicable and consistent with the public hearing requirements in § 60.23;

(viii) Compilation of public comments and the State's response thereto; and

(ix) Such other criteria for completeness as may be specified by the Administrator under the applicable emission guidelines.

(3) *Technical criteria.* In order to be deemed complete, a State plan must contain each of the following technical criteria:

(i) Description of the plan approach and geographic scope;

(ii) Identification of each affected source, identification of emission standards for the affected sources, and monitoring, recordkeeping and reporting requirements that will determine compliance by each affected source;

(iii) Identification of compliance schedules and/or increments of progress;

(iv) Demonstration that the State plan submittal is projected to achieve emissions performance under the applicable emission guidelines;

(v) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and

(vi) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

§ 60.28a Plan revisions by the State.

(a) Plan revisions shall be submitted to the Administrator within 12 months, or shorter if required by the Administrator, after notice of the availability of a final revised emission guideline is published under § 60.22a, in accordance with the procedures and requirements applicable to development and submission of the original plan.

(b) A revision of a plan, or any portion thereof, shall not be considered part of an applicable plan until approved by the Administrator in accordance with this subpart.

§ 60.29a Plan revisions by the Administrator.

After notice and opportunity for public hearing in each affected State, the Administrator may revise any provision of an applicable federal plan if:

(a) The provision was promulgated by the Administrator, and

(b) The plan, as revised, will be consistent with the Act and with the requirements of this subpart.

■ 7. Add subpart UUUUa to read as follows:

Subpart—UUUUa Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Subpart—UUUUa Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Introduction

§ 60.5700a What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish standards of performance limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit for the purposes of this subpart, is referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or subpart Ba of this part, the requirements of this subpart will apply.

§ 60.5705a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The emission guidelines for greenhouse gases established in this subpart are heat rate improvements which target achieving lower carbon dioxide (CO_2) emission rates at affected EGUs.

(b) PSD and Title V thresholds for greenhouse gases are set out in this paragraph (b).

(1) For the purposes of § 51.166(b)(49)(ii), with respect to GHG emissions from 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) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the plan, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2, with respect to greenhouse gas emissions from facilities regulated in the plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 71.2 of this chapter.

§ 60.5710a Am I affected by this subpart?

If you are the Governor of a State in the contiguous United States with one or more affected EGUs that commenced construction on or before August 31, 2018, you are subject to this action and you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the United States with no affected EGUs for which construction commenced on or before August 31, 2018, in your State, you must submit a negative declaration letter in place of the State plan.

§ 60.5715a What is the review and approval process for my plan?

The EPA will review your plan according to § 60.27a to approve or disapprove such plan or revision or each portion thereof.

§ 60.5720a What if I do not submit a plan or my plan is not approvable?

(a) If you do not submit an approvable plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a plan.

§ 60.5725a In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a State plan submittal or a negative declaration letter (if applicable).

§ 60.5730a Is there an approval process for a negative declaration letter?

The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, an affected EGU for which construction commenced on or before August 31, 2018 is found in your State, you will be found to have failed to submit a final plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a final State plan.

State Plan Requirements

§ 60.5735a What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (4) of this section in your plan submittal. The final plan must meet the requirements of, and include the information required under, § 60.5740a.

(1) *Identification of affected EGUs.* Consistent with § 60.25a(a), you must identify the affected EGUs covered by your plan and all affected EGUs in your State that meet the applicability criteria in § 60.5775a. In addition, you must include an inventory of CO_2 emissions from the affected EGUs during the most recent calendar year for which data is available prior to the submission of the plan.

(2) *Standards of performance.* You must provide a standard of performance for each affected EGU according to § 60.5755a and compliance periods for each standard of performance according to § 60.5750a. In establishing a standard of performance, the state must evaluate all of the heat rate improvements described in § 60.5740a.

(3) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5785a.

(4) *State reporting.* Your plan must include a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress, including information required under § 60.5795a.

(b) You must follow the requirements of subpart Ba of this part and demonstrate that they were met in your State plan.

§ 60.5740a What must I include in my plan submittal?

(a) In addition to the components of the plan listed in § 60.5735a, a state plan submittal to the EPA must include the information in paragraphs (a)(1) through (8) of this section. This information must be submitted to the EPA as part of your plan submittal but will not be codified as part of the federally enforceable plan upon approval by EPA.

(1) You must include a summary of how you determined each standard of performance for each affected EGU according to § 60.5755a(a). You must include in the summary an evaluation of the applicability of each of the following heat rate improvements to each affected EGU:

(i) Neural network/intelligent sootblowers

(ii) Boiler feed pumps

(iii) Air heater and duct leakage control

(iv) Variable frequency drives

(v) Blade path upgrades for steam turbines

(vi) Redesign or replacement of economizer

(vii) Improved operating and maintenance practices

(2) In applying a standard of performance, if you consider remaining useful life and other factors for an affected EGU as provided in § 60.24a(e), you must include a summary of the application of the relevant factors in deriving a standard of performance.

(3) You must include a demonstration that each affected EGU's standard of performance is quantifiable, non-duplicative, permanent, verifiable, and enforceable according to § 60.5755a.

(4) Your plan demonstration, if applicable, must include the information listed in paragraphs (a)(4)(i) through (v) of this section as applicable.

(i) A summary of each affected EGU's anticipated future operation characteristics, including:

(A) Annual generation;

(B) CO_2 emissions;

(C) Fuel use, fuel prices (when applicable), fuel carbon content;

(D) Fixed and variable operations and maintenance costs (when applicable);

(E) Heat rates; and

(F) Electric generation capacity and capacity factors.

(ii) A timeline for implementation of EGU-specific actions (if applicable).

(iii) All wholesale electricity prices.

(iv) A time period of analysis, which must extend through at least 2035.

(v) A demonstration that each standard of performance included in your plan meets the requirements of § 60.5755a.

(5) Your plan submittal must include a timeline with all the programmatic milestone steps the State intends to take between the time of the State plan submittal and [date three years after the notice of availability of a final emission guideline is published in the **Federal Register**] to ensure the plan is effective as of [date plan takes effect].

(6) Your plan submittal must adequately demonstrate that your State has the legal authority (*e.g.,* through regulations or legislation) and funding to implement and enforce each component of the State plan submittal, including federally enforceable standards of performance for affected EGUs.

(7) Your plan submittal must include certification that a hearing required under § 60.23a(c)on the State plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission, pursuant to the requirements of § 60.27a(f).

(8) Your plan submittal must include supporting material for your plan including:

(i) Materials demonstrating the State's legal authority to implement and enforce each component of its plan, including standards of performance, pursuant to the requirements of § 60.27a(f) and § 60.5740a(a)(6);

(ii) Materials supporting calculations for affected EGU's standards of performance according to § 60.5755a; and

(iii) Any other materials necessary to support evaluation of the plan by the EPA.

(b) You must submit your final plan to the EPA electronically according to § 60.5800a.

§ 60.5745a What are the timing requirements for submitting my plan?

You must submit a plan with the information required under § 60.5740a by [date three years after the notice of availability of a final emission guideline is published in the **Federal Register**].

§ 60.5750a What schedules, performance periods, and compliance periods must I include in my plan?

The standards of performance for affected EGUs regulated under the plan must include compliance periods. Any compliance period extending more than 24 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities.

§ 60.5755a What standards of performance must I include in my plan?

(a) You must set a standard of performance for each affected EGU within the state.

(1) The standard of performance must be an emission performance rate relating mass of CO_2 emitted per unit of energy (*e.g.* pounds of CO_2 emitted per MWh).

(2) In establishing any standard of performance, you must consider the applicability of each of the heat rate improvements included in § 60.5740a(1) to the affected EGU.

(i) In applying a standard of performance to any affected EGU, you may consider the source-specific factors included in § 60.24(e).

(ii) If you consider source-specific factors to apply a standard of performance, you must include a demonstration in your plan submission for how you considered such factors.

(b) Standards of performance for affected EGUs included under your plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The plan submittal must include the methods by which each standard of performance meets each of the requirements in paragraphs (c) through (f) of this section.

(c) An affected EGU's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.

(d) An affected EGU's standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the standard of performance.

(e) An affected EGU's standard of performance is permanent if the standard of performance must be met for each compliance period, unless it is replaced by another standard of performance in an approved plan revision.

(f) An affected EGU's standard of performance is enforceable if:

(1) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(2) Compliance requirements are clearly defined;

(3) The affected EGU responsible for compliance and liable for violations can be identified;

(4) Each compliance activity or measure is enforceable as a practical matter; and

(5) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its standard of performance based on its emissions) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)–(h), in the case of a State, pursuant to its plan, State law or CAA section 304, as applicable, and in the

case of third parties, pursuant to CAA section 304.

§ 60.5760a What is the procedure for revising my plan?

EPA-approved plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart Ba of this part, including the requirements in § 60.5740a. If one (or more) of the elements of the plan set in § 60.5735a require revision, a request must be submitted to the Administrator indicating the proposed revisions to the plan to ensure the CO_2 emission performance are met.

§ 60.5765a What must I do to meet my plan obligations?

To meet your plan obligations, you must demonstrate that your affected EGUs are complying with their standards of performance as specified in § 60.5755a.

Applicability of Plans to Affected EGUs

§ 60.5770a Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State. However, affected EGU owners or operators must comply with the plan that a State develops to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a plan to implement and enforce the emission guidelines contained in this subpart by [date three years after the notice of availability of a final emission guideline is published in the **Federal Register**], or the date that EPA disapproves a final plan, the EPA will implement and enforce a Federal plan, as provided in § 60.27a(c), applicable to each affected EGU within the State that commenced construction on or before January 8, 2014.

§ 60.5775a What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any affected EGU that commenced construction on or before August 31, 2018.

(b) An affected EGU is a steam generating unit that meets the relevant applicability conditions specified in paragraph (b)(1) through (2), as applicable, of this section except as provided in § 60.5780a.

(1) Serves a generator connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (*i.e.,* capable of selling greater than 25 MW of electricity);

(2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

§ 60.5780a What EGUs are excluded from being affected EGUs?

(a) An EGU that is excluded from being an affected EGU is:

(1) An EGU that is subject to subpart TTTT of this part as a result of commencing construction, reconstruction or modification after the subpart TTTT applicability date;

(2) A steam generating unit that is, and always has been, subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

(3) A stationary combustion turbine that meets the definition of either a combined cycle or combined heat and power combustion turbine;

(4) An IGCC unit;

(5) A non-fossil unit (*i.e.,* a unit that is capable of combusting 50 percent or more non-fossil fuel) that has always limited the use of fossil fuels to 10 percent or less of the annual capacity factor or is subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(6) An EGU that is a combined heat and power unit that has always limited, or is subject to a federally enforceable permit limiting, annual net-electric sales to a utility distribution system to no more than the greater of either 219,000 MWh or the product of the design efficiency and the potential electric output;

(7) An EGU that serves a generator along with other steam generating unit(s), IGCC(s), 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;

(8) An EGU that is a municipal waste combustor unit that is subject to subpart Eb of this part; or

(9) An EGU that is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(b) [Reserved]

§ 60.5785a What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for affected EGUs?

(a) Your plan must include monitoring, recordkeeping, and reporting requirements for affected EGUs. To satisfy this requirement, you have the option of either:

(1) Specifying that sources must report emission and electricity generation data according to part 75 of this chapter; or

(2) Describing an alternative monitoring, recordkeeping, and reporting program that includes specifications for the following program elements:

(i) Monitoring plans that specify the monitoring methods, systems, and formulas that will be used to measure CO_2 emissions;

(ii) Monitoring methods to continuously and accurately measure all CO_2 emissions, CO_2 emission rates, and other data necessary to determine compliance or assure data quality;

(iii) Quality assurance test requirements to ensure monitoring systems provide reliable and accurate data for assessing and verifying compliance;

(iv) Recordkeeping requirements;

(v) Electronic reporting procedures and systems; and

(vi) Data validation procedures for ensuring data are complete and calculated consistent with program rules, including procedures for determining substitute data in instances where required data would otherwise be incomplete.

(b) [Reserved]

Recordkeeping and Reporting Requirements

§ 60.5790a What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan for each interim step and the interim period. After [date plan takes effect], States must keep records of all information relied upon in support of any continued demonstration that the final CO_2 emission performance rates or CO_2 emissions goals are being achieved.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that is used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5785a.

(c) If your State has a requirement for all hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in Part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 5 years from the date the record is used to determine compliance with a standard of performance or plan requirement. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5795a What are my reporting and notification requirements?

You must submit an annual report as required under § 60.25a(e) and (f).

§ 60.5800a How do I submit information required by these Emission Guidelines to the EPA?

(a) You must submit to the EPA the information required by the emission guidelines in this subpart following the procedures in paragraphs (b) through (e) of this section.

(b) All negative declarations, State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States who claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539–01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the [date three years after the notice of availability of a final emission guideline is published in the **Federal Register**], deadline for plan submittal so that the official will have the ability to submit a plan in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization, and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

Definitions

§ 60.5805a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts TTTT, A (General Provisions) and subpart Ba of this part.

Affected electric generating unit or *Affected EGU* means a steam generating unit that meets the relevant applicability conditions in section § 60.5775a, except as provided in § 60.5780a.

Air heater means a device that recovers heat from the flue gas for use in pre-heating the incoming combustion air and potentially for other uses such as coal drying.

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.

Boiler feed pump (or *boiler feedwater pump*) means a device used to pump feedwater into a steam boiler at an EGU. The water may be either freshly supplied or returning condensate produced from condensing steam produced by the boiler.

CO_2 emission rate means for an affected EGU, the reported CO_2 emission rate of an affected EGU used by an affected EGU to demonstrate compliance with its CO_2 standard of performance.

Combined heat and power unit or *CHP unit,* (also known as ''cogeneration'') means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means a discrete time period for an affected EGU to comply with a standard of performance.

Economizer means a heat exchange device used to capture waste heat from boiler flue gas which is then used to heat the boiler feedwater.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material to create useful heat.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Intelligent sootblower means an automated system that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup at a steam generating unit.

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

Nameplate capacity means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous State under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Neural network means a computer model that can be used to optimize combustion conditions, steam temperatures, and air pollution at steam generating unit.

Programmatic milestone means the implementation of measures necessary for plan progress, including specific dates associated with such implementation. Prior to [date plan takes effect], programmatic milestones are applicable to all state plan approaches and measures.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Useful thermal output means the thermal energy made available for use in any 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), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Variable frequency drive means an adjustable-speed drive used on induced draft fans and boiler feed pumps to control motor speed and torque by varying motor input frequency and voltage.

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and /or heat.

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