ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2025–0124; FRL–12674–01–OAR]

RIN 2060–AW55

Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this action, the U.S. Environmental Protection Agency (EPA) is proposing to repeal all greenhouse gas (GHG) emissions standards for fossil fuel-fired power plants. The EPA is proposing that the Clean Air Act (CAA) requires it to make a finding that GHG emissions from fossil fuel-fired power plants contribute significantly to dangerous air pollution, as a predicate to regulating GHG emissions from those plants. The EPA is further proposing to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. The EPA is also proposing, as an alternative, to repeal a narrower set of requirements that includes the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines.

DATES: *Comments.* Comments must be received on or before August 7, 2025.

Public Hearing. The EPA will hold a virtual public hearing on July 8, 2025. Please refer to the **SUPPLEMENTARY INFORMATION** section for information on registering for the public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2025–0124, by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2025–0124 in the subject line of the message.
- Fax: (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2025–0124.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2025–0124, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Lisa Thompson, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5158; and email address: *thompson.lisa@epa.gov.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. The public hearing will be held via virtual platform on July 8, 2025. The hearing will convene at 11 a.m. Eastern Time (ET) and conclude at 7 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers.

The EPA will begin pre-registering speakers for the hearing no later than 1 business day following the publication of this document in the **Federal Register**. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power* or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* The last day to pre-register to speak at the hearing will be June 29, 2025. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to submit a copy of their oral testimony as written comments electronically to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.* While the EPA expects the hearing to go forward as described in this section, please monitor our website or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by June 24, 2025. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for these rulemakings under Docket ID No. EPA–HQ–OAR–2025–0124. All documents in the docket are listed in the *Regulations.gov* index. Although listed in the index, 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.

Written Comments. Direct your comments to Docket ID No. EPA–HQ–OAR–2025–0124 at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

The EPA is soliciting comment on numerous aspects of the proposed rule. The EPA has indexed each comment solicitation with a unique identifier (*e.g.,* ''C–1'', ''C–2'', ''C–3'' . . .) 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 either in a heading or within the text of each comment, 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 proposed action.

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. The 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). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI or multimedia submissions; and general guidance on making effective comments.

The *https://www.regulations.gov* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *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, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and should be free of any defects or viruses.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* 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 the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and 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 *Written Comments* section of this document. 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 and note the docket ID. 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.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the Office of Air Quality Planning and Standards (OAQPS) CBI Office at the email address *oaqpscbi@epa.gov* and, as described above, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the U.S. Postal Service, please send it 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–2025–0124. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

Preamble acronyms and abbreviations. Throughout this document the use of ''we,'' ''us,'' or ''our'' is intended to refer to the EPA. The EPA uses 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, the EPA defines the following terms and acronyms here:

ACE Affordable Clean Energy [rule]
BSER best system of emission reduction
CAA Clean Air Act
CCS carbon capture and sequestration/storage
CFR Code of Federal Regulations
CO_2 carbon dioxide
CPS Carbon Pollution Standards
CPP Clean Power Plan
EGU electric generating unit
EPA Environmental Protection Agency
FR Federal Register
GHG greenhouse gas
MW megawatt
MWh megawatt-hour
NSPS new source performance standards
RIA regulatory impact analysis

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

I. Executive Summary

In this action, the U.S. Environmental Protection Agency (EPA) is proposing to repeal all greenhouse gas (GHG) standards for fossil fuel-fired power plants. The EPA is proposing that Clean Air Act (CAA) section 111 requires it to make a finding that GHG emissions from fossil fuel-fired power plants contribute significantly to dangerous air pollution, as a predicate to regulating GHG emissions from plants in this source category. The EPA is further proposing to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution within the meaning of the statute. The EPA is also proposing, as an alternative, to repeal a narrower set of requirements that include the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines. In the regulatory impact analysis, we present the potential impacts of the proposal and alternative proposal in one shared set of estimates for the years 2026 to 2047, discounting monetized estimates to 2025 under 3 and 7 percent discount rates. Over the 2026 to 2047 period, the present value (PV) of the estimated compliance cost savings is $19 billion under a 3 percent discount rate, and $9.6 billion under a 7 percent discount rate for both the proposal and the alternative proposal.

With this action, the EPA proposes to resolve a decade's worth of regulatory uncertainty brought on by the Agency's novel attempts to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. The EPA attempted to restrict GHG emissions from power plants for the first time in 2015, when it issued both new source performance standards for new power plants (the 2015 NSPS) [1] and emission guidelines for existing power plants (the Clean Power Plan (CPP)).[2] Despite in effect listing fossil fuel-fired power plants as a new source category for the purpose of regulating GHG emissions, the EPA interpreted CAA section 111 as authorizing the regulation of any air pollutant so long as there was a rational basis for doing so, and asserted that the Agency was not required to make a finding of significant contribution to dangerous air pollution before regulating sources within the new source category. In the alternative, the EPA stated that it would make such a finding if required by the statute, and based that finding on the absolute volume of GHG emissions from fossil fuel-fired power plants.

In *West Virginia* v. *EPA,* 597 U.S. 697 (2022), the U.S. Supreme Court struck down these efforts in large part, ruling that CAA section 111 does not authorize the EPA to regulate fossil fuel-fired power plants by capping GHG emissions at a level that forces a nationwide transition away from the use of coal to generate electricity.[3] Rather than change course, however, the EPA responded by promulgating a new rule that embraced the goals of the 2015 NSPS and CPP by expanding restrictions on certain new sources and regulating existing sources in a similarly stringent manner.

The EPA's most recent effort to regulate GHG emissions from the power sector, commonly referred to as the Carbon Pollution Standards (CPS), includes standards of performance for new and reconstructed fossil fuel-fired combustion turbines and for certain modified fossil fuel-fired steam-generating power plants, as well as rules directing States to set standards of performance for existing fossil fuel-fired steam generating power plants.[4] Aspects of these standards are premised on one type of power plant—coal-fired plants—converting to another type that would be partially fired with an entirely different fuel, *i.e.,* natural gas. Additionally, in the course of the rulemaking and subsequent litigation over the CPS, numerous States, regulated entities, and other stakeholders warned that these standards exceed the EPA's authority to mandate already demonstrated technologies, not technologies that will not be widely available until sometime in the future, are based on inadequately demonstrated technologies, are unachievable, threaten to impose massive costs on the power sector, and do not adequately ensure the national interest in affordable, reliable electricity.

On January 20, 2025, President Trump issued Executive Order 14154, ''Unleashing American Energy,'' which directs federal agencies, including the EPA, to review existing regulations ''to identify those agency actions that impose an undue burden on the identification, development, or use of domestic energy resources—with particular attention to oil, natural gas, coal, hydropower, biofuels, critical mineral, and nuclear energy resources.'' [5] In the course of this review, the EPA has identified GHG emissions standards [6] for power plants as one such action. The Executive Order further affirms that it is, ''the policy of the United States to ensure that all regulatory requirements related to energy are grounded in clearly applicable law.'' [7]

On February 19, 2025, President Trump issued an Executive Order titled ''Ensuring Lawful Governance and Implementing the President's 'Department of Government Efficiency' Deregulatory Initiative.'' [8] This Executive Order established a national policy requiring agencies, including the EPA, to ''focus the executive branch's limited enforcement resources on regulations squarely authorized by constitutional Federal statutes'' and to ''initiate a process to review all regulations subject to their sole or joint jurisdiction for consistency with law

[1] ''Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule,'' 80 FR 64510 (October 23, 2015).

[2] ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule,'' 80 FR 64662 (October 23, 2015).

[3] *See West Virginia* v. *EPA,* 597 U.S. 697, 735 (2022) (Congress did not give EPA authority to adopt a regulatory scheme that ''cap[s] carbon dioxide emissions at a level that will force a nationwide transition away from the use of coal to generate electricity'').

[4] ''New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Final Rule,'' 89 FR 39798 (May 9, 2024).

[5] Executive Order 14154 section 3(a).

[6] References to ''GHG standards'' here and elsewhere include new source performance standards (NSPS) promulgated under CAA section 111(b) and emission guidelines for existing sources promulgated under CAA section 111(d).

[7] Executive Order 14154, section 2.

[8] Executive Order 14219.

and Administration policy.'' [9] Among other things, the Executive Order instructed agencies to identify ''regulations that are based on anything other than the best reading of the underlying statutory authority or prohibition'' [10] and ''regulations that implicate matters of social, political, or economic significance that are not authorized by clear statutory authority.'' [11] In the course of this review, the EPA has identified GHG standards for power plants as regulations that may be based on interpretations that are inconsistent with the best reading of CAA section 111 and address a significant issue without clear statutory authorization.

On April 8, 2025, President Trump issued an Executive Order titled, ''Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241.'' [12] This Executive Order stated that ''coal is essential to our national and economic security'' and established ''a national priority to support the domestic coal industry by removing Federal regulatory barriers that undermine coal production.'' [13] The Executive Order specifically found that ''beautiful clean coal resources will be critical to meeting the rise in electricity demand due to the resurgence of domestic manufacturing and the construction of artificial intelligence data processing centers'' and to increasing ''energy supply,'' lowering ''electricity costs,'' stabilizing the power grid, creating ''high paying jobs,'' supporting ''burgeoning industries,'' and assisting allies abroad.[14] Accordingly, the Executive Order directed the EPA, among other agencies, to ''identify any guidance, regulations, programs, and policies within their respective executive department or agency that seek to transition the Nation away from coal production and electricity generation'' [15] and ''consider revising or rescinding Federal actions identified in subsection (a) of this section consistent with applicable law.'' [16]

The EPA has concluded its initial review of GHG emissions standards for the power sector, as directed by Executive Order 14154, Executive Order 14219, and Executive Order 14261, and has substantial concerns about the legal and technical underpinnings of its efforts since 2015 to regulate GHG emissions from fossil fuel-fired power plants. Based on a reassessment of the legal and technical conclusions in the 2015 NSPS and CPS, the EPA is proposing to repeal the GHG emissions standards for new and existing sources in the fossil fuel-fired power plant source category.

Specifically, the EPA is proposing to conclude that CAA section 111 is best read to require, or at least authorize the EPA to require, an Administrator's determination that an air pollutant emitted by a source category causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare as a predicate to establishing emission standards for that pollutant. As relevant to this action, in the 2015 NSPS the EPA listed all fossil fuel-fired electric generating units (EGUs)—combining the previously existing steam generator and combustion turbine categories—as a distinct source category for purposes of promulgating standards for GHG emissions. Nevertheless, the EPA asserted in 2015 that it was not required to make a significant contribution finding for the newly listed category because sources within the category had previously been listed under CAA section 111(b)(1).[17]

As such, the EPA proposes to conclude that, at a minimum, the Administrator must make a significant contribution finding before issuing GHG emission standards for a new source category even if covered sources had previously been listed under a distinct category.

The EPA is further proposing to determine, in a change from the 2015 NSPS and CPS, that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution as required for the promulgation of new and existing source standards. The Agency is proposing that a determination of significant contribution must consider whether such determination would have an influence or effect on the targeted air pollution and the public health or welfare impacts attributed to such air pollution. This inquiry necessarily entails considering the policies that would inform the resulting regulation. In this instance, the EPA is proposing to find that any regulation of GHG emissions from fossil fuel-fired EGUs under CAA section 111 would not have a significant effect on GHG air pollution and the public health or welfare impacts attributed to such air pollution, and that the contribution of this source category is therefore not significant, because GHG emissions from those sources are a small and decreasing part of global emissions; cost-effective control measures are not reasonably available; and because this Administration's priority is to promote the public health or welfare through energy dominance and independence secured by using fossil fuels to generate power. On this basis of proposing to find that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution, the EPA is proposing to repeal all GHG emissions standards for the power sector under CAA section 111, specifically the 2015 NSPS, codified in 40 CFR part 60, subpart TTTT; and the CPS codified in 40 CFR part 60, subparts TTTTa and UUUUb.

Further, in the course of its review, the EPA reexamined the best systems of emission reduction (BSERs) for fossil fuel-fired power plants in the recently promulgated CPS to ensure that all regulatory requirements related to energy are grounded in clearly applicable law.[18] As discussed below, the EPA is proposing, as an alternative to repealing the GHG emissions standards for new and existing sources in subparts TTTT, TTTTa, and UUUUb on the basis of a proposed determination that GHG emissions from fossil fuel-fired power plants do not significantly contribute to dangerous air pollution, to revise the BSER determinations in the CPS as follows.

First, the EPA is proposing to determine that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units because 90 percent CCS has *not* been adequately demonstrated and its costs are *not* reasonable. In a change from the CPS, the EPA proposes to conclude that experimental projects aiming to achieve 90 percent CCS were not a sufficient basis to conclude the technology has already been adequately demonstrated. Furthermore, because it is extremely unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA is proposing to determine that the degree of emission limitation in the CPS for long-term coal-fired steam generating units is not achievable. The EPA proposes to conclude that its contrary determination in the CPS was inadequately supported and exceeded the Agency's authority by mandating a degree of emission reduction that would not be achievable until sometime in the future when the relevant technologies are sufficiently available.

[9] *Id.* sections 1, 2(a).

[10] *Id.* section 2(a)(iii).

[11] *Id.* section 2(a)(iv).

[12] Executive Order 14261.

[13] *Id.* section 2.

[14] *Id.* section 1.

[15] *Id.* section 6(a).

[16] *Id.* section 6(b).

[17] 80 FR 64529–32 (October 23, 2015).

[18] Executive Order 14154, section 2(d).

Second, the EPA is proposing to determine that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units because a thorough consideration of the ''energy requirements'' BSER factor in CAA section 111(a)(1) shows that natural gas co-firing in a steam generating unit is an inefficient use of natural gas. Additionally, the EPA is proposing to conclude that 40 percent natural gas co-firing constitutes impermissible generation shifting under *West Virginia,* and that the Agency erred in the CPS by construing *West Virginia* too narrowly in this respect. Moreover, the EPA proposes that the associated degree of emission limitation is not achievable because it is extremely unlikely the necessary pipeline infrastructure can be deployed in the time provided under the CPS. Based on these proposed conclusions, the EPA is proposing to repeal the requirements in the emission guidelines related to existing long-term and medium-term coal-fired steam generating units.

Third, the EPA is proposing to repeal the requirements in the emission guidelines related to natural gas-c9and oil-fired steam generating units because it would be an inefficient use of State resources to develop, submit, and implement State plans solely for natural gas-and oil-fired steam generating units, which comprise a relatively small part of the source category and would result in few or no emission reductions under the existing emission guidelines. Consequently, the EPA is proposing to repeal the emission guidelines for existing fossil fuel-fired steam generating units in their entirety.

Fourth, because the EPA is proposing that 90 percent CCS is neither adequately demonstrated nor cost-reasonable, the EPA is proposing to repeal the CCS-based requirements for coal-fired steam generating units undertaking a large modification.

Finally, the EPA is proposing that 90 percent CCS is neither adequately demonstrated nor cost-reasonable for new base load combustion turbines. Furthermore, because it is extremely unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA is proposing to determine that the phase 2 standards of performance in the CPS for new base load combustion turbines are not achievable. The contrary determinations in the CPS appear to be in error for many of the same reasons that apply to existing coal-fired steam generating units. Consequently, the EPA is proposing to repeal the phase 2 CCS-based requirements for new base load stationary combustion turbines.

II. General Information

A. Action Applicability

The source category that is the subject of this action is composed of fossil fuel-fired electric utility steam generating units. The 2022 North American Industry Classification System (NAICS) code for the source category is 221112. This is not intended to be exhaustive but rather provides a guide for readers regarding the entities that this proposed action is likely to affect.

The proposed repeal of 40 CFR part 60, subpart UUUUb, once promulgated, would be applicable to States currently required to develop and submit State plans pursuant to Clean Air Act (CAA) section 111(d). The proposed repeal of 40 CFR part 60, subpart TTTT, once promulgated, would be applicable to affected facilities that commenced construction or modification after January 8, 2014, or reconstruction after June 18, 2014, and on or before May 23, 2023. The proposed repeal of 40 CFR part 60, subpart TTTTa, once promulgated, would be applicable to affected facilities that began construction, reconstruction, or modification after May 23, 2023. Federal, State, local, and Tribal government entities that own and/or operate electric generating units (EGUs) subject to 40 CFR part 60, subparts TTTT and TTTTa would be affected by this proposed action.

In the alternate proposal, the proposed repeal of 40 CFR part 60, subpart UUUUb, once promulgated, would be applicable to States currently required to develop and submit State plans pursuant to CAA section 111(d). The proposed revisions to 40 CFR part 60, subpart TTTTa, once promulgated, would be applicable to affected facilities that began construction, reconstruction, or modification after May 23, 2023. Federal, State, local, and Tribal government entities that own and/or operate EGUs subject to 40 CFR part 60, subpart TTTTa would be affected by this proposed action.

B. Where to Get a Copy of This Document and Other Related Information

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

Memoranda showing the edits that would be necessary to incorporate the changes under the two alternate proposals to 40 CFR part 60, subparts TTTT, TTTTa, and UUUUb are available in the docket for this action. Following signature by the EPA Administrator, the EPA also will post a copy of the documents at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

III. Background

A. Statutory Authority

As described in this section of the preamble, CAA section 111 authorizes the EPA to establish emission standards for new stationary sources and emission guidelines for existing stationary sources under certain conditions. This provision, along with agencies' authority to reconsider prior regulations, provides the EPA's statutory authority for this proposed action.[19]

1. Regulation of Emissions From New Sources

CAA section 111(b)(1)(A) requires the EPA Administrator to promulgate a list of categories of stationary sources that the Administrator, ''in his judgment,'' finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, and distinguish among classes, types, and sizes within categories in establishing the standards. Once the EPA lists a source category that contributes significantly to dangerous air pollution, the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for ''new sources'' in the source category. These standards are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to the sources subject to them.

Under CAA section 111(a)(1), a ''standard of performance'' is defined as

[19] *See Clean Air Council* v. *Pruitt,* 862 F.3d 1, 8 (D.C. Cir. 2017) (''Agencies obviously have broad discretion to reconsider a regulation at any time.''); *see also FDA* v. *Wages & White Lion Invs., LLC,* 145 S. Ct. 898 (2025); *FCC* v. *Fox TV Stations, Inc.,* 556 U.S. 502 (2009); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29 (1983).

''a standard for emissions of air pollutants'' that is determined in a specified manner. Under CAA section 111(a)(2), a ''new source'' is defined as ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section, which will be applicable to such source.'' Under CAA section 111(a)(4), ''modification'' means ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' While this provision treats modified sources as new sources, EPA regulations also treat a source that undergoes ''reconstruction,'' by substantially replacing its components, as a new source.[20]

When the EPA establishes or revises a performance standard, CAA section 111(a)(1) provides that such standard must ''reflect[ ] 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.'' Thus, the term ''standard of performance'' as used in CAA section 111 makes clear that the EPA must determine both the ''best system of emission reduction . . . adequately demonstrated'' (BSER) for emissions of the relevant air pollutants by regulated sources in the source category and the ''degree of emission limitation achievable through the application of the [BSER].'' [21] As explained further below, to determine the BSER, the EPA first identifies the ''system[s] of emission reduction'' that are ''adequately demonstrated,'' and then determines the ''best'' of those adequately demonstrated systems, ''taking into account'' factors including ''cost,'' ''nonair quality health and environmental impact,'' and ''energy requirements.'' The EPA then derives from that system an ''achievable'' ''degree of emission limitation.'' The EPA must then, under CAA section 111(b)(1)(B), promulgate ''standard[s] for emissions''—the NSPS—that reflect that level of stringency. The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER for emissions of the relevant air pollutants and may subcategorize sources accordingly.[22]

2. Regulation of Emissions From Existing Sources

The EPA has generally used CAA section 111 to establish standards for emissions of air pollutants from *new* sources within a category. In the rare instances in which the new stationary source standards concern air pollutants that are not regulated under the National Ambient Air Quality Standards (NAAQS) program pursuant to CAA sections 108–110, or the National Emission Standards for Hazardous Air Pollutants (NESHAP) program pursuant to CAA section 112, the promulgation of standards for new stationary sources triggers a requirement that the EPA also promulgate regulations for emissions of that pollutant from *existing* sources within the same category under CAA section 111(d).[23]

CAA section 111(d) establishes a framework of ''cooperative federalism for the regulation of existing sources.'' [24] Under CAA section 111(d)(1)(A)–(B), the EPA must ''prescribe regulations'' that require ''[e]ach state . . . to submit to [EPA] a plan . . . which establishes standards of performance for any existing stationary source for'' the air pollutant at issue, and which ''provides for the implementation and enforcement of such standards of performance.'' CAA section 111(a)(6) defines an ''existing source'' as ''any stationary source other than a new source.''

As part of carrying out this obligation, the EPA promulgates ''emission guidelines'' for States that identify the BSER and the degree of emission limitation achievable through the application of the BSER. Each State must then establish standards of performance for emissions of the air pollutant at issue by covered sources that reflect that level of stringency.[25] States need not compel regulated sources to adopt the particular components of the BSER itself; rather, States have discretion in designing the policies and rules their sources will use to achieve the degree of emission limitation required by the EPA's emission guidelines. The statute also requires the EPA's regulations to permit a State, ''in applying a standard of performance to any particular source,'' to ''take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' [26] Once the EPA approves a State's plan, the provisions in the plan become federally enforceable against the source, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the CAA.[27] If a State elects not to submit a plan or submits a plan that the EPA does not find ''satisfactory,'' the EPA is authorized to promulgate a plan that establishes Federal standards of performance for the State's existing sources.[28]

3. Key Elements of Determining a Standard of Performance

Congress first defined the term ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act, amended the definition in the Clean Air Act Amendments (CAAA) of 1977, and then amended the definition again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAA. The D.C. Circuit has reviewed CAA section 111 rulemakings on numerous occasions since 1973 and has developed a body of caselaw that interprets the term.[29]

The basis for standards of performance, whether promulgated by the EPA under CAA section 111(b) or established by the States under CAA section 111(d) in response to emission guidelines promulgated by the Agency, is the ''degree of emission limitation'' that is ''achievable'' by sources in the source category by application of the ''best system of emission reduction'' that the EPA determines is ''adequately demonstrated'' (BSER). As explained further below in this section, the D.C. Circuit has explained that systems are not ''adequately demonstrated'' if they are ''purely theoretical or experimental.'' [30] The D.C. Circuit has stated that in determining the ''best''

[20] 40 CFR 60.15.

[21] *West Virginia* v. *EPA,* 597 U.S. 697, 709 (2022).

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

[23] *See* CAA section 111(d)(1)(A)(i) and (ii); *West Virginia,* 597 U.S. at 710 (''[r]eflecting the ancillary nature of Section 111(d), EPA has used it only a handful of times since the enactment of the statute in 1970.'').

[24] *American Lung Ass'n* v. *EPA,* 985 F.3d 914, 931 (D.C. Cir. 2021) *rev'd in part, West Virginia* v. *EPA,* 597 U.S. 697 (2022).

[25] As discussed below, CAA section 111(d)(1)(B) provides that, in certain circumstances, States may apply standards of performance that are less stringent than the degree of emission limitation the EPA determines in the emission guidelines.

[26] CAA section 111(d)(1).

[27] CAA section 111(d)(2)(B).

[28] CAA section 111(d)(2)(A).

[29] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011); *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021), *rev'd in part, West Virginia* v. *EPA,* 597 U.S. 697 (2022). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

[30] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973).

adequately demonstrated system for the pollutants at issue, the EPA must also take into account ''the amount of air pollution'' reduced.[31] The D.C. Circuit has also stated that the EPA may weigh the various factors identified in the statute and caselaw to determine the ''best'' system and has emphasized that the EPA has significant discretion in weighing the factors.[32]

After determining the BSER, the EPA sets an achievable emission limit based on application of the BSER.[33] For a CAA section 111(b) rule, the EPA determines the standard of performance that reflects the achievable emission limit. For a CAA section 111(d) rule, the States have the obligation of establishing standards of performance for the affected sources that reflect the degree of emission limitation that the EPA has determined and provided to States as part of an emission guideline. In applying these standards to existing sources, States are permitted to take a source's remaining useful life and other factors into account.

In identifying ''system[s] of emission reduction, the EPA has historically followed a ''technology-based approach'' that focuses on ''measures that improve the pollution performance of individual sources,'' such as ''add-on controls.'' [34] The EPA departed from its historical approach in a significant way in the CPP by setting a BSER in which the ''system'' of emissions reduction involved shifting electricity generation from one type of fuel to another. In *West Virginia,* the Supreme Court applied the major questions doctrine to hold that the term ''system'' did not provide the requisite clear authorization to support the CPP's BSER, which the Court described as ''carbon emissions caps based on a generation shifting approach'' [35] that capped GHG ''emissions at a level that will force a nationwide transition away from the use of coal to generate electricity[.]'' [36] The Court explained that the EPA's BSER ''forc[es] a shift throughout the power grid from one type of energy source to another,'' which constituted '' 'unprecedented power over American industry' '' and was different in kind from the type of ''system'' of emissions reduction envisioned by CAA section 111(d).[37]

To qualify for selection as the BSER, the system of emission reduction must be ''adequately demonstrated'' as ''the Administrator determines.'' The plain text of CAA section 111(a)(1), and in particular the terms ''adequately'' and ''the Administrator determines,'' confer discretion to the EPA in identifying the appropriate system, including making scientific and technological determinations and considering a broad range of policy considerations.[38] However, the terms ''adequately'' and ''demonstrated,'' as well as applicable caselaw, make clear that the EPA may not determine that a ''purely theoretical or experimental'' system is ''adequately demonstrated.'' [39] Moreover, applicable case law and the text and structure of CAA section 111, including, in particular, the eight-year review requirement in CAA section 111(b)(1)(B), place an outer bound on any discretion the EPA may have to project technological development into the future. The EPA has historically taken the position that because the regulated sources must be able to use the system to meet the applicable standards of performance for the relevant air pollutants by the applicable compliance date, the system must be available to the sources in time to achieve the standards. A system that will not be generally available for use in achieving the standard until technological enhancements have been developed, which may occur until years into the future, is therefore not ''adequately demonstrated.'' In the CPS, the EPA departed from this historical position by selecting a BSER of 90 percent CCS that might not, if ever, be demonstrated and widely available as a general matter until sometime in the future. Because the CPP attempted a different approach to regulating fossil fuel-fired power plants, the Supreme Court's decision in *West Virginia* did not address this aspect of the EPA's approach in the CPS.

In addition, CAA section 111(a)(1) requires the EPA to account for ''the cost of achieving [the emission] reduction'' in determining the adequately demonstrated BSER. Although the CAA does not describe how the EPA is to account for costs to affected sources, the D.C. Circuit has formulated the cost standard in various ways, including stating that the EPA may not adopt a standard the cost of which would be ''excessive'' or ''unreasonable.'' [40] The EPA has discretion in considering cost under section 111(a), both in determining the appropriate level of costs and in balancing costs with other BSER factors.[41] The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance.[42]

Under CAA section 111(a)(1), the EPA is required to take into account ''any nonair quality health and environmental impact and energy requirements'' in determining the BSER. Nonair quality health and environmental impacts may include the impacts of the disposal of byproducts of the air pollution controls, or requirements of the air pollution control equipment for water.[43] Energy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs.[44] In addition, based on the D.C. Circuit's interpretations of CAA section 111, energy requirements may also include the impact, if any, of the air pollution controls on the energy supply for a particular area or nationwide.[45] In addition, the EPA has considered under this statutory factor whether possible controls would create risks to the reliability of the electricity system.

The D.C. Circuit has also held that the term ''best'' authorizes the EPA to consider factors in addition to the ones enumerated in CAA section 111(a)(1) that further the purpose of the statute. In particular, consistent with the plain

[31] *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981). The D.C. Circuit has stated that EPA must also take into account ''technological innovation.'' *See id.* at 347.

[32] *See Lignite Energy Council,* 198 F.3d at 933 (''Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them.'').

[33] See, *e.g.,* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews (77 FR 49494; August 16, 2012) (describing the three-step analysis in setting a standard of performance).

[34] *See West Virginia* v. *EPA,* 597 U.S. at 727 (quoting the CPP).

[35] *Id.* at 732.

[36] *Id.* at 734.

[37] *Id.* at 728 (citation omitted).

[38] *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 786 (D.C. Cir. 1976); *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 434 (D.C. Cir. 1973).

[39] *Essex Chem. Corp.,* 486 F.2d at 433–34; *see Portland Cement Assn.* v. *Ruckelshaus,* 486 F.2d 375, 391–92 (D.C. Cir. 1973) (EPA may not base an ''adequately demonstrated'' determination on a '' 'crystal ball' inquiry'') (citation omitted).

[40] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981). *See* 79 FR 1430, 1464 (January 8, 2014); *Lignite Energy Council,* 198 F.3d at 933 (costs may not be ''exorbitant''); *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975) (costs may not be ''greater than the industry could bear and survive'').

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

[42] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973); *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981).

[43] *Portland Cement Ass'n* v. *Ruckelshaus,* 465 F.2d 375, 387–88 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974).

[44] For details on the modeled energy requirements associated with CCS, please see section 6.4 of the RIA for this rule.

[45] *See Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583–84; June 11, 1979); 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

language and the purpose of CAA section 111(a)(1), which requires the EPA to determine the ''best system of *emission reduction*'' (emphasis added), the EPA must consider the quantity of emissions at issue.[46] In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA has broad discretion. In *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS'' [47] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard,'' including the amount of emission reductions, the cost of the controls, and the non-air quality environmental impacts and energy requirements.[48]

A standard of performance is ''achievable'' if a technology can reasonably be projected to be available to an individual source at the time it is constructed so as to allow it to meet the standard.[49] Although the courts have established this approach for achievability in cases concerning CAA section 111(b) new source standards of performance, a generally comparable approach should apply under CAA section 111(d), although the BSER may differ in some cases as between new and existing sources due to, for example, higher costs of retrofit.[50] For existing sources, CAA section 111(d)(1) requires the EPA to establish regulations for State plans that, in turn, must include ''standards of performance.'' As the Supreme Court has recognized, this provision requires the EPA to promulgate emission guidelines that determine the BSER for a source category and then identify the degree of emission limitation achievable by application of the BSER.[51]

[46] *Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981). The D.C. Circuit has also held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' *See id.* at 346–47.

[47] See *AEP* v. *Connecticut,* 564 U.S. 410, 427 (2011); *Sierra Club* v. *Costle,* 657 F.2d at 319.

[48] *Sierra Club* v. *Costle,* 657 F.2d at 321; *New York* v. *Reilly,* 969 F.2d at 1150.

[49] *Sierra Club* v. *Costle,* 657 F.2d 298, 364, n.276 (D.C. Cir. 1981).

[50] 40 FR 53340 (November 17, 1975).

[51] *See West Virginia* v. *EPA,* 597 U.S. at 710; 40 CFR 60.21(e), 60.21a(e) (definition of ''emission guideline'' includes provision of the degree of emission limitation achievable through the application of the BSER as determined by the Administrator).

4. EPA Promulgation of Emission Guidelines for States To Establish Standards of Performance

CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a procedure similar to that provided by CAA section 110 under which States submit State plans that establish and implement ''standards of performance'' for emissions of certain air pollutants from existing sources which, if they were new sources, would be regulated under CAA section 111(b). The term ''standard of performance'' is defined under CAA section 111(a)(1), as quoted earlier in this preamble. Thus, CAA sections 111(a)(1) and (d)(1) collectively require the EPA to determine the degree of emission limitation achievable through application of the BSER to existing sources and to promulgate regulations under which States establish standards of performance reflecting that degree of emission limitation. The EPA addresses both responsibilities through its emission guidelines, as well as through its general implementing regulations for CAA section 111(d).

Following the EPA's promulgation of emission guidelines, each State must establish standards of performance with respect to the relevant air pollutants for its existing sources, which the EPA's regulations call ''designated facilities.'' [52] Such standards of performance must reflect the degree of emission limitation achievable through application of the best system of emission reduction for the relevant pollutants as determined by the EPA, which the Agency may express as a presumptive standard of performance in the applicable emission guidelines.

While the standards of performance that States establish in their plans must generally be no less stringent than the degree of emission limitation determined by the EPA,[53] CAA section 111(d)(1) also requires that the EPA's regulations ''permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' The EPA's implementing regulations for CAA section 111(d) provide a framework for States' consideration of a facility's remaining useful life and other factors (referred to as ''RULOF'') when applying a standard of performance to a particular source. The State must include the standards of performance in the plan submitted to the EPA for review according to the procedures established in the Agency's implementing regulations for CAA section 111(d).[54] Under CAA section 111(d)(2)(A), the EPA must approve State plans that are determined to be ''satisfactory.'' CAA section 111(d)(2)(A) also gives the Agency ''the same authority'' as that conferred under CAA section 110(c) to promulgate a Federal plan in cases where a State fails to submit a satisfactory plan.

[52] 40 CFR 60.21a(b), 60.24a(b).

[53] 40 CFR 60.24(c), 60.24a(c).

B. EPA Regulation of GHG Emissions Under CAA Section 111

This section discusses the EPA's efforts since 2015 to regulate GHG emissions under CAA section 111, including the regulation of electric generating units (EGUs) and the associated caselaw, insofar as it is relevant to this action. This background is relevant because it explains the current rules that are directly affected by this proposed action, as well as the EPA's asserted legal basis for regulating GHG emissions under CAA section 111, which is implicated by this proposed action.

The EPA has regulated air pollutants from power plants under CAA section 111 since 1971, when the Agency listed ''fossil fuel-fired steam generators of more than 250 million Btu per hour heat input'' as a source category under CAA section 111(b)(1)(A) [55] and subsequently promulgated NSPS for certain air pollutants.[56] In 1977, the EPA listed fossil fuel-fired stationary combustion turbines in a category under CAA section 111(b)(1)(A) [57] and subsequently promulgated NSPS for certain air pollutants.[58] However, the EPA did not invoke CAA section 111 to regulate GHG emissions from power plants until 2015, when it promulgated the 2015 NSPS, which addressed GHG emissions, as measured by the equivalent of CO_2 emissions, from new fossil fuel-fired EGUs under CAA section 111(b),[59] and the CPP, which set emission guidelines directing States to regulate GHG emissions, as measured by the equivalent of CO_2 emissions, from existing EGUs under CAA section 111(d).[60]

[54] *See generally* 40 CFR 60.23a–60.28a.

[55] 36 FR 5931 (March 31, 1971) (listing).

[56] See, *e.g.,* 36 FR 24876 (December 23, 1971); 40 CFR 60 subpart Da.

[57] 42 FR 53657 (October 3, 1977) (listing ''stationary gas turbines'').

[58] See, *e.g.,* 44 FR 62792 (September 10, 1979); 40 CFR 60 subpart KKKK.

[59] ''Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule,'' 80 FR 64510 (October 23, 2015).

[60] ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility

Continued

In the 2015 NSPS, the Agency asserted that it was *not* required to make a finding of significant contribution under CAA section 111 before regulating GHG emissions. The EPA explained the legal basis for this interpretation as follows: The EPA noted that it had listed fossil fuel-fired steam generators as a source category in 1971 and combustion turbines as a source category in 1979, in each case on the basis of the sources' emissions of non-GHG air pollutants, and the EPA acknowledged that it had not considered GHG emissions at the time of those listings. Even so, in the 2015 NSPS, the EPA stated that it interpreted CAA section 111 to provide that once the EPA had listed a source category once, it was authorized to promulgate NSPS for any air pollutant from a source listed in that source category, so long as it had a rational basis for doing so.[61]

The EPA received comments on the 2015 NSPS stating that CAA section 111 did not authorize regulation of GHGs from EGUs until the Agency first makes a finding that emissions of GHGs from EGUs contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Such a finding is shorthanded here as a pollutant-specific significant contribution finding, and such air pollution is shorthanded here as dangerous air pollution. The EPA disagreed with those comments. The EPA explained that CAA section 111(b)(1)(A), 111(b)(1)(B), and 111(a)(1), read together, authorize the EPA to regulate an air pollutant from a listed source category, subject to the standards of rationality under CAA section 307(d)(9)(A),[62] and do not require the EPA to make an additional determination, as a predicate for regulation, that the air pollutant contributes significantly to dangerous air pollution.

In the 2015 NSPS, the EPA took the additional step of ''combining the steam generator and combustion turbine categories into a single category of fossil fuel-fired electricity generating units for purposes of promulgating standards of performance for GHG emissions.'' [63] The EPA explained that ''[c]ombining the two categories is reasonable because they both provide the same product: Electricity services,'' and that doing so was consistent with the Agency's decision to combine the categories ''in the CAA section 111(d) rule for existing sources that accompanies this rule,'' *i.e.,* in the CPP.[64] The EPA added that it did not consider this combining of the source categories to constitute a new listing of the resultant source category.[65]

In the 2015 NSPS, notwithstanding its position that CAA section 111 does not require a pollutant-specific significant contribution finding for GHG emissions, the EPA added, in the alternative, that it was making that finding for GHG emissions from EGUs. The EPA explained that it based this finding on the volume of GHG emissions emitted by EGUs, coupled with the EPA's 2009 determination that GHG air pollution endangered public health or welfare and subsequently available information.[66]

The 2015 NSPS promulgated standards of performance to limit emissions of GHGs, manifested as CO_2, from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units, *i.e.,* utility boilers and integrated gasification combined cycle (IGCC) combustion turbines and newly constructed and reconstructed stationary combustion turbines. These final standards are codified in 40 CFR part 60, subpart TTTT. In promulgating the 2015 NSPS for newly constructed fossil fuel-fired steam generating units, the EPA determined the BSER to be a new, highly efficient, supercritical pulverized coal (SCPC) EGU that implements post-combustion partial CCS technology.

The 2015 NSPS also included standards of performance for steam generating units that undergo a ''reconstruction'' as well as units that implement ''large modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent). The 2015 NSPS did not establish standards of performance for steam generating units that undertake ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent), due to the limited information available to inform the analysis of a BSER and corresponding standard of performance.

The 2015 NSPS also finalized standards of performance for newly constructed and reconstructed natural gas-fired stationary combustion turbines that operate at base load and non-base load, based on efficient natural gas combined cycle (NGCC) technology or the use of lower-emitting fuels (referred to as clean fuels in the 2015 NSPS) as the BSER. The EPA did not promulgate final standards of performance for modified stationary combustion turbines under CAA section 111(d) due to lack of information.

The 2015 NSPS was challenged in the D.C. Circuit, but the case has been held in abeyance in light of the EPA's subsequent rulemakings.

In the CPP—promulgated at the same time that the EPA promulgated the 2015 NSPS—the EPA interpreted CAA section 111(d) to require the Agency to regulate GHG emissions from existing sources in the newly combined source category because the EPA had promulgated NSPS for GHG emissions from new sources in that source category.[67] The EPA determined that the BSER for existing fossil fuel-fired EGUs consisted primarily of generation shifting measures, as described earlier in this preamble.[68] The Supreme Court stayed the CPP pending review in February 2016,[69] and the D.C. Circuit held the litigation in abeyance and ultimately dismissed it in light of subsequent developments.[70]

In 2018, the EPA proposed to revise the NSPS for new, modified, and reconstructed fossil fuel-fired steam generating units and IGCC units (2018 NSPS Proposal).[71] The EPA proposed to revise the NSPS for newly constructed units, based on a revised BSER of a highly efficient EGU without partial CCS. The EPA also proposed to revise the NSPS for modified and reconstructed units. As explained later in this section, the 2018 NSPS Proposal was never finalized and, as noted below, was rescinded as part of the Carbon Pollution Standards.

In 2019, the EPA repealed the CPP and replaced it with the Affordable Clean Energy (ACE) Rule.[72] In contrast to the CPP, the EPA determined in the ACE Rule that under the provisions of CAA section 111, a system of emission reduction is limited to measures that can be applied to at the level of the individual source and cannot include generation shifting measures.[73] Instead, the EPA determined the BSER for existing coal-fired EGUs to be heat rate improvements alone. Specifically, the

Generating Units; Final Rule,'' 80 FR 64662 (October 23, 2015).

[61] 80 FR 64529–31 (October 23, 2015).

[62] Promulgation of NSPS under CAA section 111(b)(1)(B) is subject to the requirements of CAA section 307(d), under CAA section 307(d)(1)(C).

[63] 80 FR 64531 (October 23, 2015).

[64] *Id.*

[65] *Id.* at 64532.

[66] *Id.* at 64530–31.

[67] 80 FR 64702 (October 23, 2015).

[68] *Id. at* 64728–29.

[69] *West Virginia* v. *EPA,* 577 U.S. 1126 (2016).

[70] *American Lung Ass'n,* 985 F.3d at 937.

[71] ''Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Proposed Rule,'' 83 FR 65424 (December 20, 2018).

[72] ''Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations; Final Rule,'' 84 FR 32520 (July 8, 2019).

[73] 84 FR 32523–24 (July 8, 2019).

EPA listed various technologies that could improve heat rate and identified the ''degree of emission limitation achievable'' by providing ranges of expected emission reductions associated with each of the technologies.[74] The EPA also explained that it was not determining CCS to be the BSER in part because of its unreasonable expense, and was not determining natural gas co-firing to be the BSER because it was an inefficient use of natural gas.[75]

In 2021, the D.C. Circuit vacated the ACE Rule, including the CPP Repeal.[76] The court held, among other things, that CAA section 111 did not limit the EPA, in determining the BSER, to measures applied at and to an individual source, and that CAA section 111 did authorize the EPA to determine generation shifting as the BSER. The D.C. Circuit concluded that as a result, both the CPP Repeal and the ACE Rule should be vacated.[77] The court did not address most other challenges to the ACE Rule, including the arguments concerning the heat rate improvement BSER.

Several petitioners argued that the ACE Rule was invalid on the grounds that the EPA had predicated regulation of GHG emissions from existing EGUs on the new source GHG emissions standards in the 2015 NSPS, and that those standards were flawed because CAA section 111 required them to be predicated on a pollutant-specific significant contribution finding with identified standards or criteria for determining significance. The D.C. Circuit held that it did not need to decide whether CAA section 111 requires a pollutant-specific significant contribution finding for GHG emissions from EGUs as a predicate for CAA section 111 regulation because the EPA had made such a finding in the alternative. The court rejected the Petitioners' argument that the significant contribution finding was flawed due to lack of identified criteria for significance and explained that the magnitude of GHG emissions from EGUs supported the significance finding without identified criteria for significance.[78]

In 2022, the Supreme Court in *West Virginia* reversed the D.C. Circuit's decision to vacate the ACE Rule's embedded repeal of the CPP.[79] As noted above, the Court concluded that the CPP's BSER of ''generation shifting'' implicated the major questions doctrine and exceeded the EPA's statutory authority because CAA section 111 did not clearly authorize the Agency to cap GHG emissions at a level that forces a nationwide transition away from using coal to generate electricity.[80]

On October 27, 2022, the D.C. Circuit responded to the Supreme Court's decision by taking steps to, among other things, ensure that the CPP remained repealed but that the ACE Rule came back into effect. Following a change in administration, the EPA informed the court that it intended to replace the ACE Rule. Accordingly, the court stayed further proceedings with respect to the ACE Rule, including the various challenges to the heat rate improvement BSER.[81]

C. Carbon Pollution Standards

On May 9, 2024, the EPA promulgated the Carbon Pollution Standards (CPS), which consisted of several rules and actions.[82] The first action was the repeal of the ACE Rule. The EPA explained, among other things, that the suite of heat rate improvements that was identified in the ACE Rule as the BSER is not an appropriate BSER for existing coal-fired EGUs.[83]

In addition, the CPS included emission guidelines for GHG emissions from existing fossil fuel-fired steam generating units, which include the separate subcategories of coal-fired units, oil-fired units, and gas-fired units.[84] For long-term coal-fired units, the EPA finalized 90 percent CCS as the BSER, with a presumptive standard of an 88.4 percent reduction in annual emission rate and a compliance deadline of January 1, 2032. The EPA asserted that 90 percent CCS is an adequately demonstrated technology that achieves significant emissions reduction and is cost-reasonable, taking into account the supposedly declining costs of the technology and the IRC section 45Q tax credit available for a certain number of years to generating sources that use CCS technology. In recognition of the significant capital expenditures involved in deploying CCS technology and the fact that a number of regulated units had announced retirement dates, the EPA finalized a separate subcategory for existing coal-fired units that demonstrate that they plan to permanently cease operation before January 1, 2039. For this subcategory, the BSER is co-firing with natural gas, at a level of 40 percent of the unit's annual heat input, the presumptive standard is a 16 percent reduction in annual emission rate, and the compliance deadline is January 1, 2030. In addition, the EPA exempted existing coal-fired units demonstrating that they plan to permanently cease operation prior to January 1, 2032. The EPA determined that these controls were cost-effective primarily by reference to two metrics it used in prior rulemakings. The first determines the cost in dollars for each ton or other quantity of the regulated air pollutant removed through the system of emission reduction. The second, which the EPA particularly relied on in rules for the electric power sector, determines the dollar increase in the cost of a MWh of electricity generated by the affected sources due to the emission controls, which shows the cost of controls relative to the output of electricity.[85]

For existing gas- and oil-fired steam generating units, the EPA further subcategorized them into base load (units with annual capacity factors greater than or equal to 45 percent), intermediate load (units with annual capacity factors greater than or equal to 8 percent and less than 45 percent), and low load (units with annual capacity factors less than 8 percent) subcategories. The EPA finalized routine methods of operation and maintenance as the BSER for base load and intermediate load units, with presumptive standards for base load units of 1,400 lb CO_2/MWh-gross, and for intermediate load units of 1,600 lb CO_2/MWh-gross. For low load units, the EPA finalized a uniform fuels BSER and a presumptive input-based standard of 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources.

The CPS also includes standards of performance for new and reconstructed combustion turbines, organized into three subcategories: base load, intermediate load, and low load. For base load turbines, the standard consists of two components to be implemented in two phases. The first component is

[74] *Id.* at 32535–38.

[75] *Id.* at 32545.

[76] *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021).

[77] 985 F.3d at 995.

[78] *Id.* at 974–77.

[79] *West Virginia* v. *EPA,* 597 U.S. 697 (2022).

[80] *Id.* at 734–35.

[81] *American Lung Ass'n* v. *EPA,* No. 19–1140, Order (October 27, 2022).

[82] ''New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Final Rule'', 89 FR 39798 (May 9, 2024).

[83] In the CPS, the EPA also withdrew the separate proposed revisions to the New Source Review (NSR) regulations that were included the ACE Rule proposal (83 FR 44773–83, August 31, 2018).

[84] Although, in the proposed CPS, the EPA proposed emission guidelines for GHG emissions from existing fossil fuel-fired combustion turbines, it did not finalize those guidelines.

[85] 89 FR 39882 (May 9, 2024).

based on a BSER of highly efficient generation, which is determined according to the emission rates that the best performing units are achieving, and compliance was required upon the effective date of the CPS. The second component is based on a BSER of 90 percent CCS, and compliance is required on January 1, 2032. For intermediate load turbines, the EPA determined the BSER to be highly efficient simple-cycle generation; and for low load combustion turbines, the EPA determined the BSER to be the use of lower-emitting fuels.

In addition, the EPA revised the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.,* a modification that increases its hourly emission rate by more than 10 percent) to be based on the BSER of 90 percent CCS. Finally, the EPA withdrew the 2018 proposed amendments [86] to the NSPS for GHG emissions from coal-fired EGUs.

Following promulgation of the CPS, 27 States and numerous industry groups filed petitions for review in the D.C. Circuit, and many subsequently filed motions to stay the rule. The D.C. Circuit denied the stay motions on July 19, 2024,[87] and the Supreme Court denied them on October 16, 2024.[88] However, Justice Thomas would have granted a stay and Justice Kavanaugh, joined by Justice Gorsuch, wrote that ''the applicants have shown a strong likelihood of success on the merits as to at least some of their challenges to the [EPA's] rule.'' [89] The merits case was briefed, and oral argument was held before the D.C. Circuit on December 6, 2024. Following a change in administration, the D.C. Circuit agreed to hold the case in abeyance pending further actions by the Agency.

IV. Summary and Rationale of Primary Proposal

A. Summary of Proposed Action

The EPA is proposing that CAA section 111 is best read to require, or at least authorize the EPA to require, an Administrator's determination that an air pollutant emitted by a source category causes, or contributes significantly to, dangerous air pollution as a predicate to establishing emissions standards for that pollutant. In the context of the 2015 NSPS and CPS, the mandatory form of this interpretation would require the EPA to determine that GHG emissions from EGUs contribute significantly to dangerous air pollution before regulating GHG emissions from fossil fuel-fired EGUs. This proposal would reverse the EPA's most recent interpretation on that point, which asserted that the EPA could regulate GHG emissions from existing source categories of fossil fuel-fired EGUs and, in fact, combine those source categories into a single source category and regulate it solely on the basis of GHG emissions, without making the significant contribution finding for GHG emissions.

The EPA is further proposing to determine, as an exercise of the Administrator's judgement and based on the available evidence, that GHG emissions from fossil fuel-fired EGUs do not contribute significantly to dangerous air pollution for purposes of CAA section 111(b). This proposal would rescind the EPA's prior, alternative determination to the contrary in the 2015 NSPS as carried over into the CPS. On this basis, the EPA is proposing to repeal all GHG emissions standards and emission guidelines for the power sector, specifically the 2015 NSPS codified in 40 CFR part 60, subpart TTTT (80 FR 64510; October 23, 2015), and the CPS codified in 40 CFR part 60, subparts TTTTa and UUUUb (89 FR 39798; May 9, 2024).

As explained below, the EPA seeks comment on its proposed interpretation of CAA section 111 to require, or at least authorize the EPA to require, an Administrator's determination of significant contribution for the air pollutant under consideration. Separately, the EPA seeks comment on whether CAA section 111 requires a significant contribution finding for the fossil fuel-fired EGU source category first created in the 2015 NSPS. Finally, the EPA seeks comment on its interpretation of what it means for a source category to contribute ''significantly'' to dangerous air pollution, and on the proposed Administrator's determination that GHG emissions from sources within the fossil fuel-fired EGU source category do not contribute significantly to such pollution. The EPA encourages commenters to present any other relevant arguments and information, including with respect to legitimate reliance interests on the 2015 NSPS and CPS.

B. Significant Contribution Finding for EGUs

In this section, the EPA first explains the legal bases for its proposal that CAA section 111 requires, or at least authorizes the EPA to require, that the EPA determine that GHG from the fossil fuel-fired EGU source category contribute significantly to dangerous air pollution as a predicate for regulation. The EPA then explains its reasons for proposing to determine that GHG emissions from this source category do not contribute significantly to dangerous air pollution within the meaning of CAA section 111.

1. Requirement for Significant Contribution Determination

a. Requirement for a Significant Contribution Determination Concerning GHG Emissions From the EGU Source Category

As noted in section III.B above, prior to the 2015 NSPS, the EPA had listed two separate source categories of electricity generating sources—steam generators and combustion turbines—under CAA section 111(b)(1)(A), which requires the EPA to list a source category for regulation if it determines that the source category ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA had previously promulgated NSPS only for different, non-GHG air pollutants from those source categories. In the 2015 NSPS, the EPA combined the two source categories into a single source category—''fossil fuel-fired electricity generating units''—solely for the purpose of regulating GHG emissions, but did not otherwise revise the prior source category listings or promulgated NSPS. The EPA stated that combining the source categories in this fashion did not constitute a listing of a new source category under CAA section 111(b)(1)(A),[90] and interpreted CAA section 111 to authorize it to regulate GHG emissions from the new, combined source category as long as it had a rational basis for doing so. The EPA went on to determine that, in light of the amount of GHG emissions from the source category relative to other source categories, the EPA had a rational basis to regulate GHG emissions. The EPA added that even if it were required to determine that GHG emissions from the source category contribute significantly to dangerous air pollution as a predicate

[86] 83 FR 65424 (December 20, 2018).

[87] *West Virginia* v. *EPA,* No. 2420 Order, 2024 U.S. App. LEXIS 17856 (July 19, 2024).

[88] *West Virginia* v. *EPA,* 145 S. Ct. 2 (2024).

[89] *Id.*

[90] Specifically, the EPA stated, ''Because these two source categories are pre-existing listed source categories and the EPA will not be subjecting any additional sources in the categories to CAA regulation for the first time, the combination of these two categories is not considered a new source category subject to the listing requirements of CAA section 111(b)(1)(A). As a result, this final rule does not list a new category under CAA section 111(a)(1)(A), nor does this final rule revise either of the two source categories. Thus, the EPA is not required to make a new endangerment and contribution finding for the combination of the two categories. . . .'' 80 FR 64532 (October 23, 2015).

for regulation, it was making that determination in the alternative, and cited the same facts it relied on for the rational basis determination.

Notwithstanding the EPA's statements in the 2015 NSPS, its action in combining the two source categories for purpose of regulating GHG emissions had the effect of listing a new combined source category under CAA section 111(b)(1)(A) based solely on the emission of GHGs by sources within the new category. In light of the CAA section 111(b)(1)(A) requirement that a source category may be listed only if ''it causes, or contributes significantly to, [dangerous] air pollution,'' the EPA proposes that the creation of a single source category solely on the basis of GHG emissions is justifiable only if the GHG emissions ''cause[], or contribute[] significantly to, [dangerous] air pollution.''[91] In a change from its position in the 2015 NSPS, the EPA proposes to conclude that a new source category, whether consisting of previously unregulated sources or sources previously regulated under distinct categories, cannot be listed without the Administrator's determination of significant contribution required by the statute. Relatedly, the EPA proposes to conclude that Congress required the EPA to identify more than a rational basis for regulating emissions from a source category, as evidenced by the statute's use of ''cause, or contributes significantly'' in relation to ''air pollution which may reasonably be anticipated to endanger public health or welfare.''

In the 2015 NSPS, the EPA purported, in the alternative, to make a significant contribution finding for GHG emissions from EGUs within the newly established source category. Under the interpretation the EPA is proposing in this action, this finding was, and is, a necessary predicate for regulation. In a change from this alternative finding, and as discussed later in this section, the EPA is now proposing to determine that GHG emissions from fossil fuel-fired EGUs do not contribute significantly to dangerous air pollution within the meaning of CAA section 111. This determination would preclude the EPA from regulating GHG emissions from fossil fuel-fired EGUs. The EPA proposes to conclude that such a determination would be consistent with agencies' authority to reconsider prior decisions,[92] and with the relevant statutory text. In particular, CAA section 111(b)(1)(A) instructs the Administrator to use ''his judgment'' in making significant contribution findings, and further authorizes the EPA to ''from time to time . . . revise'' the list of source categories regulated under CAA section 111. In effect, the EPA is proposing to revise the list of source categories to remove the combined source category of fossil fuel-fired EGUs that emit GHGs that was created for the first time in the 2015 NSPS, while retaining pre-existing source categories for EGUs and related regulations for different, non-GHG pollutants.

b. Requirement for Pollutant-Specific Significant Contribution Finding

As noted in section III.B of this preamble, in the 2015 NSPS, the EPA justified its regulation of GHG emissions from fossil fuel-fired steam generators and combustion turbines primarily by interpretating CAA section 111 to authorize the regulation of air pollutants emitted by sources within an existing source category without an Administrator's determination of significant contribution to dangerous air pollution, so long as the EPA had a rational basis for such regulation. In this action, the EPA proposes to interpret CAA section 111 as requiring the EPA to determine that emissions of an air pollutant from an existing source category significantly contribute to dangerous air pollution before imposing standards of performance for that air pollutant on the relevant source categories.

The EPA proposes to conclude that CAA section 111 is best read to require an Administrator's determination as a predicate for regulating emissions of an air pollutant by an existing source category. Once the EPA lists a source category for regulation under CAA section 111(b)(1)(A) on grounds that the EPA determines that ''it causes, or contributes significantly to, [dangerous] air pollution,'' the EPA is required, under CAA section 111(b)(1)(B), to promulgate ''standards of performance'' for new sources in the category. CAA section 111(a)(1) defines ''standard of performance'' as ''a standard for emissions of air pollutants'' determined in a specified manner. Thus, CAA section 111(b)(1)(B) requires that the EPA promulgate standards for ''emissions of air pollutants.'' Under longstanding practice, ''EPA undertakes this analysis on a pollutant-by-pollutant basis, establishing different standards of performance with respect to different pollutants emitted from the same source category.''[93]

Read together, CAA section 111(b)(1)(A) and 111(b)(1)(B) demonstrate that CAA section 111 directs the EPA to establish standards for air pollutants that significantly contribute to dangerous air pollution. Importantly, the source categories that the EPA is required to list under CAA section 111(b)(1)(A) typically emit multiple air pollutants, but CAA section 111(b)(1)(B) does not specify the air pollutants for which the EPA must promulgate standards. These provisions must be read in context as a cohesive whole. Interpreting CAA section 111(b)(1)(A) in isolation to authorize the EPA to list a source category based on a significance finding for one pollutant fails to give independent meaning to the broader term ''air pollution'' and effectively reads the ''contributes significantly'' requirement out of the statute with respect to all other pollutants. On one hand, this interpretation allows the EPA to evade the ''contributes significantly'' requirement by listing a source category based on one pollutant in order to regulate other pollutants for which it has not, or cannot, make a credible finding of significant contribution to dangerous air pollution. On the other, this interpretation would trigger the requirement that the EPA promulgate standards of performance under CAA section 111(b)(1)(B) for *all* air pollutants emitted by the listed source category under the definition of ''standard of performance'' in CAA section 111(a)(1). Nothing in CAA section 111 suggests that Congress intended the EPA to regulate emissions of any and all air pollutants regardless of the magnitude of emissions (*i.e.,* including de minimis emissions) and regardless of those emissions' contribution to dangerous air pollution (*i.e.,* including pollutants that are not dangerous to health or welfare). Rather, the EPA is necessarily required to exercise judgment in determining which air pollutants to regulate, and Congress directed that judgment must

[91] Note that the reference in the CAA section 111(b)(1)(A) endangerment provision to ''causes'' generally refers to emissions that are the sole part of the air pollution problem. The EPA has defined the same term in similar CAA endangerment provisions the same way. *See* ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66506 (December 15, 2009) (interpreting the CAA section 202(a)(1) endangerment provision as follows: ''In addition, by instructing the Administrator to consider whether emissions of an air pollutant cause or contribute to air pollution, the statute is clear that she need not find that emissions from any one sector or group of sources are the sole or even the major part of an air pollution problem. The use of the term 'contribute' clearly indicates a lower threshold than the sole or major cause.'').

[92] *See FDA* v. *Wages & White Lion Invs., LLC,* 145 S. Ct. 898 (2025); *FCC* v. *Fox TV Stations, Inc.,* 556 U.S. 502 (2009); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29 (1983); *Clean Air Council* v. *Pruitt,* 862 F.3d 1, 8 (D.C. Cir. 2017).

[93] *West Virginia,* 597 U.S. at 709.

be applied by determining whether an air pollutant contributes significantly to dangerous air pollution.

By analogy, the Supreme Court held in *Utility Air Regulatory Group* v. *EPA,* 573 U.S. 302, 322–23 (2014), that the phrase ''any air pollutant'' in the new source review prevention of significant deterioration (PSD) requirements under CAA sections 165(a)(1) and 169(1), which apply the PSD requirements to stationary sources that emit specified amounts of ''any air pollutant,'' do not, based on their statutory context, include GHGs, even though GHGs had been understood as air pollutants.[94] By the same token, because CAA section 111(b)(1)(A) authorizes the EPA to list a source category for regulation only if it ''contributes significantly'' to dangerous air pollution, it is appropriate to limit GHG emissions from a source category only if they contribute significantly to such dangerous air pollution. This interpretation is merited in part because the EPA did not consider GHG emissions when the Agency initially listed the fossil fuel-fired power plant source categories in the 1970s. In addition, limiting the EPA's authority to regulate GHG emissions only if they contribute significantly to dangerous air pollution is consistent with prior EPA decisions not to regulate certain air pollutants under CAA section 111 on grounds that they had little impact or that no effective controls were available.[95]

Additional context and structure in CAA section 111 suggests that CAA section 111(b)(1) is best read to require pollutant-specific contribution findings. CAA section 111(b)(3) requires the EPA to ''issue information on pollution control techniques for categories of new sources *and air pollutants* subject to the provisions *of this section.*'' [96] This language treats ''categories of new sources'' and ''air pollutants'' in the same breath, suggesting that the required findings in ''this section'' apply to both phrases. CAA section 111(h), which authorizes the EPA to impose design, equipment, work practice, or operational standards when standards of performance are not feasible, provides that standards of performance are not feasible when ''*a pollutant or pollutants* cannot be emitted through a conveyance designed and constructed to emit or capture *such pollutant.*'' [97] That language recognizes that CAA section 111(b)(1) is ultimately concerned with controlling particular pollutants, and reinforces the importance of making significant contribution determinations for such pollutants. Finally, CAA section 111(j) authorizes the EPA to waive requirements under certain conditions ''with respect to any air pollutant,'' meaning waivers are granted on a pollutant-by-pollutant, in addition to source-by-source, basis.[98] This language supports the conclusion that the EPA must analyze the contribution of pollutants to dangerous air pollution under CAA section 111 generally.

The EPA solicits comment on the interpretation that it is appropriate to regulate emissions of an air pollutant—here, GHGs—from a source category only if those emissions contribute significantly to dangerous air pollution. In particular, the EPA seeks comment with respect to the textual requirements of CAA section 111(b), relevant context from the remainder of CAA section 111, and relevant structural arguments regarding the CAA more generally, including statutory provisions not specifically discussed in this proposal.

In the alternative, the EPA proposes to interpret CAA section 111 to at least authorize the EPA to require a determination that an air pollutant—here, GHG emissions from the power sector—significantly contributes to dangerous air pollution as a predicate to imposing standards of performance. Specifically, under this alternative, the EPA proposes to interpret CAA section 111 as granting the EPA discretion to determine which air pollutants to regulate under CAA section 111(b)(1)(B). As noted above, that provision directs the EPA to establish standards for ''emissions of air pollutants,'' but those provisions do not indicate which air pollutants within a potential source category must be regulated. The EPA is proposing to interpret this language to permit the EPA to choose which pollutants to regulate based on the significant contribution standard in CAA section 111(b)(1)(A).

This alternative interpretation, under which the EPA determines that the air pollutants for which it establishes standards are those that contribute significantly to dangerous air pollution, is consistent with the overall purpose of CAA section 111 to protect the public health or welfare from source categories that contribute significantly to dangerous air pollution. This interpretation is also consistent with the discretion that CAA section 111 confers to the EPA at each stage of the rulemaking process. That is, the EPA exercises ''judgment'' in determining which source categories to list for regulation under CAA section 111(b)(1)(A)); after listing a source category, the EPA has discretion in determining which pollutants to regulate; and once the EPA has determined to regulate a particular air pollutant, it has discretion in determining the type of emission controls (BSER) that serve as the basis for the regulation under CAA section 111(a)(1).

The EPA seeks comment on this alternative interpretation, including with respect to whether the text of CAA section 111(b) confers sufficient discretion on the EPA and whether additional provisions of CAA section 111 or the CAA more generally inform the scope of that discretion. The EPA also seeks comment on whether it erred in determining that it was not required to make a significant contribution finding in the 2015 NSPS or in not revisiting the issue in the CPS, and whether or not it would be appropriate to exercise its discretion here by requiring such a finding for GHG emissions from the fossil fuel-fired power plant source category.

The EPA recognizes that the proposals discussed in this section constitute a change from the EPA's approaches to statutory interpretation in the 2015 NSPS. The EPA notes that the 2015 NSPS, which asserted that the EPA need only have a rational basis for regulating additional pollutants emitted from a new category comprised of previously regulated sources, was itself a departure from the EPA's prior implementation of CAA section 111. The 2015 NSPS regulated GHG emissions from certain new sources in the power sector for the first time since the enactment of CAA section 111(b) in 1970, and for the first time specifically articulated the rational basis interpretation as allowing the EPA to regulate additional pollutants without ever having made a significant contribution finding for that pollutant.

The EPA seeks comment on this change in interpretation, including any specific reliance interests relevant to the interpretation taken in the 2015 NSPS, as carried over into the CPS, and the relative strength of the rationale for these respective interpretations. The EPA also seeks comment on whether and how the Supreme Court's recent decision in *Loper Bright Enterprises* v.

[94] In *UARG,* the Court interpreted the similar provisions of the title V permit program, CAA sections 501(2)(B) and 302(j), the same way. 573 U.S. at 323–24.

[95] *See National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (noting EPA did not promulgate standards for oxides of nitrogen (NO_X), sulfur dioxide (SO_2) and CO from lime plants due to limited amounts of emissions and lack of effective controls).

[96] CAA section 111(b)(3) (emphases added).

[97] CAA section 111(h)(2) (emphases added).

[98] CAA section 111(j)(1)(A).

Raimondo,[99] should inform the EPA's approach to interpreting CAA section 111 and selecting which interpretation better reflects the best reading of the statute.

The EPA is also requesting comment on whether its proposed interpretation of CAA section 111(b)(1)(A) as requiring a pollutant-specific significant contribution finding is necessary to avoid implicating the major questions doctrine as articulated by the Supreme Court in *West Virginia.* Specifically, the EPA is seeking input on whether the proposed interpretations in this section are necessary to prevent the Agency from improperly expanding its regulatory authority by determining that emissions of de minimis amounts of air pollutants, or non-harmful substances that may nevertheless be defined as air pollutants, should be regulated under CAA section 111.

2. Determination of Significant Contribution

As noted above, CAA section 111(b)(1)(A) requires the Administrator to list a source category for regulation ''if in his judgment it causes, or contributes significantly to, [dangerous] air pollution.'' The EPA proposes to interpret this provision, in conjunction with other provisions in CAA section 111, to require, as a predicate for regulation of GHG emissions from a source category, that the EPA determine that such emissions ''contribute[ ] significantly'' to dangerous air pollution. By its explicit reference to the Administrator, this provision expressly delegates to the EPA the authority to determine when emissions ''contribute[ ] significantly.'' [100] This section sets out the EPA's proposed interpretation of CAA section 111's significant contribution standard and seeks comment on the strength of this interpretation and its application to GHG emissions by EGUs.

a. Proposed Interpretation of ''Significantly Contributes''

The EPA proposes to interpret ''significantly contributes'' as used in CAA section 111 as conferring discretion on the Administrator based on the statutory text, structure, and background principles of law. First, the EPA proposes to conclude that the term ''*significantly* contributes'' (emphasis added), in conjunction with the explicit grant of authority to the Administrator to exercise ''judgment,'' confers discretion to consider policy issues inherent in the statutory structure, including effectiveness of emissions reduction controls, cost-reasonableness of those controls, impacts on the affected industry, and impacts of the emissions on public health and welfare. Second, the EPA proposes to conclude that ''significantly contributes'' incorporates background legal principles of proximate cause that inform both whether an air pollutant contributes to dangerous air pollution and the extent of contribution required to trigger regulation based on the particular form of dangerous air pollution identified.

Consistent with its ordinary meaning, the term ''significant[ ]'' is defined as ''having or likely to have influence or effect: important.'' [101] ''Important'' is similarly defined, in turn, as ''marked by or indicative of significant worth or consequence : valuable in content or relationship.'' [102] Whether a source category's contribution to air pollution should be considered ''important'' or ''valuable'' entails consideration of the influence, effect, or usefulness of finding such contribution. If regulating emissions of a particular pollutant from a source category would have little effect on dangerous air pollution, that source category's contribution to the air pollution is not significant. By the same token, if regulating emissions would not be useful, taking into account, *inter alia,* the impacts on, and the Administration's policies concerning, the source category, that source category's contribution to the air pollution is not significant. An inquiry into the effect of a finding of significance necessarily involves policy considerations that will inform any subsequent regulation when making the significance determination in the first instance.[103]

This interpretation of ''significantly contributes'' accords with the structure and language of the remainder of the statutory provision. CAA section 111(b)(1)(A) does not require the EPA to conduct separate analyses of contribution and endangerment or imply that significance is divorced from the policy and regulatory tools available to address an identified danger. To the contrary, Congress required the Administrator to exercise ''judgment'' in determining whether emissions of an air pollutant from a category of sources contribute significantly to dangerous air pollution such that emissions reductions can reasonably be required. This explicit authorization to the Administrator to exercise ''judgment'' reinforces interpreting ''significantly'' to include the Administrator's policy considerations associated with reducing emissions. When Congress intends to require the EPA to evaluate the significance of a risk separately from risk mitigation, it knows how to do so. For example, unlike key provisions of the Safe Drinking Water Act (SDWA) and the Toxic Substances Control Act (TSCA), CAA section 111 uses discretionary language and does not purport to exclude any standard administrative considerations from the scope of the EPA's significance analysis.[104]

Notably, this interpretation of significance is not foreclosed by the D.C. Circuit's decision in *American Lung Association* v. *EPA.* There, the court addressed the question whether EPA had to consider certain metrics or factors when determining if a source category's contribution is significant.[105] The court declined to answer this question, finding that it was not necessary to do so in that case.[106] Under the interpretation of ''contributes significantly'' proposed here, significance would be determined not with regard to a quantitative threshold, but rather based on the impact of the resulting regulation. The *American Lung Association* decision does not speak to this interpretation, and thus does not purport to restrict the Administrator's discretion to exercise judgment by factoring in statutory policy considerations when determining significance.

The CAA, and specifically the factors laid out in section 111(a)(1), provides guidance on the scope of the considerations relevant to assessing whether an air pollutant contributes significantly to dangerous air pollution. As noted above, the EPA has discretion to consider statutory policies, including risk management considerations, in determining whether emissions contribute ''significantly,'' and CAA section 111(a)(1) includes the factors

[99] *Loper Bright* v. *Raimondo,* 144 S. Ct. 2244, 2263 & n.5 (2024).

[100] *Id.*

[101] Merriam-Webster. Dictionary Definition: Significant. *https://www.merriam-webster.com/dictionary/significant.*

[102] Merriam-Webster. Dictionary Definition: Important. *https://www.merriam-webster.com/dictionary/important.*

[103] Because CAA section 111 delegates to the EPA the authority to consider policy goals in determining whether emissions contribute ''significant[ly]'' and does not limit the meaning of ''significantly'' to some specified level of emissions, the EPA proposes to conclude that it is not necessary to identify standards or criteria for determining whether a particular level of emissions contributes ''significantly.''

[104] *See Michigan* v. *EPA,* 576 U.S. 743, 753 (2015).

[105] *American Lung Ass'n* v. *EPA,* 985 F.3d 914, 977 (D.C. Cir. 2021), *rev'd in part, West Virginia* v. *EPA,* 597 U.S. 697 (2022).

[106] *Id.*

that EPA must consider in determining emission standards to manage risk. Specifically, CAA section 111(a) requires that the EPA determine the level of emission reductions that will be required based on consideration of, among other things, the cost of achieving those reductions. If the cost is unreasonable, the associated emission reductions are not warranted. Thus, when determining if a source category contributes significantly to dangerous air pollution, the EPA will look to the availability of achievable, cost-effective emission reductions. If no such reductions are available, the influence or effect of regulating the source category for that pollutant is null and its contribution to air pollution is not significant.

The EPA has long interpreted a similar phrase in CAA section 110(a)(2)(D)(i)(I) to include cost considerations. That provision requires that state implementation plans contain provisions that prohibit sources from ''emitting any air pollutant in amounts which will contribute significantly to'' downwind air quality problems. Based on this provision, the EPA has promulgated several region-wide rules, beginning in 1998, to limit emissions of air pollutants that affect downwind air quality. In these rules, the EPA has consistently interpreted the term ''significantly'' to include consideration of the cost-effectiveness of controls in determining the overall amount of required emission reductions.[107] Although not addressing the EPA's specific interpretation, the Supreme Court read the phrase ''amounts which will contribute significantly'' to authorize the consideration of cost effectiveness.[108]

As the EPA has explained previously in examining alternatives to reduce emissions of GHGs from fossil fuel-fired EGUs, there are four main approaches to controls that can potentially be used given the continued (and increasing) demand for electricity generation.[109] Serious flaws in each of these potential controls demonstrates not only that emissions reductions are not readily achievable, but also that the contribution to dangerous air pollution that the EPA previously relied upon to regulate GHG emissions is not significant within the meaning of CAA section 111 when read in context with an eye towards the provision's structure.

The first approach is generation shifting, which the Supreme Court held in *West Virginia* cannot be considered as part of BSER. The second is the use of CCS technology at fossil fuel-fired power plants. As explained below, there is very limited use of CCS on fossil fuel-fired EGUs either in the U.S. or internationally, and the projects using CCS on a cutting-edge basis have demonstrated significantly less than 90 percent capture. Moreover, as discussed in sections V.B.1.b–c and V.2 of this preamble, the EPA is proposing to find that the cost of 90 percent CCS is unreasonable, and therefore that the associated emission reductions are not achievable. The third approach to reducing GHG emissions is natural gas co-firing. As further explained in section V.B.2 of this preamble, the EPA is proposing that basing the BSER on a switch from one fuel to an entirely different fuel would constitute impermissible generation shifting. Even if switching to natural gas were an allowable BSER for coal-fired steam generating units, in considering energy requirements, natural gas co-firing is an inefficient use of that natural gas, and natural gas is also an important and limited resource necessary to public welfare. Finally, efficiency, or heat rate improvements (HRI) can be used. For new sources, this is unlikely to have a significant impact on emissions because sources already have a significant incentive to use the most efficient technology available even without regulatory drivers. For existing sources, efficiency improvements decrease emissions per MWh of electricity generated but can result in a ''rebound effect'' where emissions at the individual EGU increase due to increased generation from the unit. Because an EGU applying HRI is more fuel efficient and may have lower dispatch costs, it may also displace generation from lower emitting EGUs (*e.g.,* an existing source displaces generation from a new natural gas combined cycle unit) so that overall emissions from the power sector may increase. As a result, HRI may be unsuitable as BSER due to the uncertainty as to whether the technology results in overall emission reductions.

Thus, the control options available to reduce GHGs from fossil fuel-fired EGUs are not permissible as BSER, not adequately demonstrated, cost unreasonable, or potentially ineffective in reducing emissions. Because it is likely that the Agency may be unable to develop a BSER that would result in any meaningful, cost-reasonable GHG emission reductions, the contribution of this source category to GHG air pollution is not significant. In particular, because, as discussed below, only extraordinary emissions reductions on a global scale would have any impact on the potential endangerment of public health and welfare in this context, the EPA is proposing to determine that GHG emissions from the EGU source category do not contribute significantly to dangerous air pollution.

The EPA proposes to conclude based on this interpretation of CAA section 111 that the significant contribution analysis is informed by considerations of national policy regarding the public welfare and the ability of the CAA section 111 regulatory mechanism to achieve meaningful reductions in air pollution that are cost-reasonable and achievable. As such, the significance analysis is informed by this Administration's national policy that energy production is essential to the public welfare. This entails continued and increasing reliance on fossil fuels to meet increasing demands for electricity generation, including to power artificial intelligence (AI) and related technologies with critical implications for national security and economic growth. Such considerations fit within the meaning of the term ''significant,'' as well as within the CAA's broad understanding of the term ''welfare'' as including (but not limited to) ''effects on economic values and on personal comfort and well-being.'' [110]

In the 2015 NSPS, the EPA took a materially different view when making, in the alternative, a significant contribution finding for GHG emissions from fossil fuel-fired power plants. There, the EPA based the finding solely on the quantity of GHG emissions and did not consider the potential impacts of its policy.[111] The limitations of this approach became evident in the CPS, where the EPA assessed impacts on the fossil fuel-fired power plants that it regulated; the Agency estimated that the CPS would result in significant coal retirements of 5 GW by 2030, an

[107] *See EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489, 499–503 (2014) (recounting history of EPA regulatory action and statutory interpretation, beginning with the ''NOx SIP Call,'' 63 FR 57356, 57358 (October 27, 1998)).

[108] *Id.* at 518–19.

[109] CPP was based on generation shifting as BSER, ACE was based on HRI as BSER, and CPS was based on co-firing and CCS as BSERs. Those prior rulemakings examine various aspects of those approaches. See CPP proposal at 79 FR 34830 (June 18, 2014), CPP final at 80 FR 64662 (October 23, 2015), ACE proposal at 83 FR 44746 (August 31, 2018), ACE final at 84 FR 32520 (July 8, 2019), CPS proposal at 88 FR 33240 (May 23, 2023), and CPS final at 89 FR 39798 (May 9, 2024). See also previous technical support documents at Docket ID No. EPA–HQ–OAR–2013–0602–36852, EPA–HQ–OAR–2023–0072–9095, and EPA–HQ–OAR–2023–0072–9099.

[110] CAA section 302(h).

[111] 89 FR 64531 (October 23, 2015).

incremental 21 GW by 2035, and an incremental 14 GW by 2040, relative to a baseline without the CPS.[112] The EPA further estimated that CPS resulted in lower amounts of generation from new gas turbines and fewer natural gas combined cycle turbines being built.[113] Notwithstanding these estimates, the Agency did not revisit its prior finding of significant contribution, and instead assumed that GHG emissions from such sources should be regulated as contributing significantly to a danger to public health and welfare, without accounting for the consequences to public health and welfare of taking action that resulted in plant closures.

In enacting and amending CAA section 111, Congress legislated against background legal principles, including principles of causation and proximate cause.[114] These ''default rules'' are ''presumed to have [been] incorporated, absent an indication to the contrary in the statute itself.'' [115] CAA section 111(b)(1)(A) incorporates these principles by using the term ''cause'' and the phrase ''significantly contribute'' without accompanying language that suggests an intent to depart from ordinary rules of legal meaning. The EPA proposes to interpret CAA section 111(b)(1)(A) as incorporating ordinary causation and proximate cause principles that must be considered in determining whether the emission of an air pollutant ''significantly contributes'' to dangerous air pollution in light of the directness and degree of the supposed contribution.[116]

In the 2015 NSPS, the EPA assigned itself a particularly demanding analytical task by evaluating the significance of contribution to global, well-mixed air pollution that results from a combination of pollutants from a large and diverse array of sources that in turn, creates elevated global concentrations that, in turn, the Agency determined play a causal role in environmental phenomena that, in turn, the Agency determined adversely affect the public health and welfare. The global scale of that analysis and attenuated chain of causation stands in marked contrast to the EPA's prior listing and regulatory efforts under CAA section 111. None of those listings and regulatory efforts concerned air pollutants that can be connected to adverse public health and welfare impacts only when aggregated into global emissions from all potential global sources.

The threshold for significant contribution under this theory is heightened by the multiple intervening actors, uncertainties, and extrapolations necessary to draw a connection between emissions by a source category and dangerous air pollution in the form of adverse effects in the U.S. from anthropogenic climate change, as discussed further below. Under the EPA's proposed interpretation, this attenuated causal chain would require a greater volume and percentage of contribution than a more direct causal relationship to account for the degree of uncertainty and extrapolations involved. In other words, emissions of an air pollutant by a source category cannot be said to contribute significantly to a third or fourth order adverse consequence involving multiple independent domestic and global actors unless the contribution is sufficiently significant that regulation would have a discernable impact on the potential danger.

b. Proposed Application of ''Significantly Contributes''

In the 2015 NSPS, the EPA found, in the alternative, that GHG emissions from domestic fossil fuel-fired EGUs ''significantly contribute'' to dangerous air pollution based exclusively on the volume of GHG emissions from the source category.[117] In addition, the Agency relied on its conclusion in the 2009 Endangerment Finding that global GHG air pollution causes anthropogenic climate change that, in turn, caused adverse domestic impacts.[118] The EPA's theory at the time can be summarized as follows: (1) GHG emissions from U.S. fossil fuel-fired EGUs combine with GHGs emitted from other U.S. sources; (2) U.S. GHG emissions combine with global emissions of GHGs from all sources in all countries to produce a combined concentration of GHGs in the atmosphere; (3) that combined concentration of GHGs in the atmosphere plays a causal role in a net trend toward increasing temperatures; (4) that net trend toward increasing temperatures plays a causal role in global environmental, climate, weather, and oceanographic patterns; and (5) those global changes play a causal role in producing adverse domestic environmental, climate, weather, and oceanographic phenomena that (6) endanger the public health and welfare.

The EPA now proposes to adopt a statutory interpretation that is centered on the impacts and effects of statutory policy considerations in determining whether a source category's contribution is significant, rather than a purely quantitative measure of significance resting on the absolute volume of emissions from a source category.[119] Based on this interpretation, the Agency proposes to conclude, as an exercise of the Administrator's informed judgment, that the volume of GHG emissions from U.S. fossil fuel-fired EGUs does not demonstrate the significant contribution to dangerous air pollution required to invoke the Agency's regulatory authority under CAA section 111. This proposed determination is based on the considerations of statutory structure and policy regarding public welfare discussed in the previous section, available information on the declining share of GHG emissions from U.S. EGUs relative to global emissions, and the attenuated nature of the causal chain between the volume of GHG emissions from the EGU source category and potential danger to public health and welfare arising from anthropogenic climate change.

Unlike other air pollutants that can have a localized or regional impact and direct consequences to human health, GHGs are global pollutants. The share of GHG emissions from the U.S. power sector, including CO_2, to global concentrations of GHGs in the atmosphere is relatively minor and has been declining over time. In 2005, U.S. electric power sector GHG emissions comprised 5.5 percent of total global GHG emissions. This percentage has fallen steadily since then to 4.6 percent

[112] U.S. EPA. Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule. May 2024. Document ID No. EPA–HQ–OAR–2023–0072–8913. Page 3–28.

[113] *Id.* Page 3–29.

[114] See, *e.g.,* Bank of Am. Corp. v. City of Miami, 581 U.S. 189, 201 (2017); *Lexmark Int'l, Inc.* v. *Static Control Components, Inc.,* 572 U.S. 118, 132 (2014); *Univ. of Tex. Sw. Med. Ctr.* v. *Nassar,* 570 U.S. 338, 347 (2013).

[115] Nassar, 570 U.S. at 347.

[116] The Supreme Court has explained, ''[t]he proximate-cause analysis asks 'whether the harm alleged has a sufficiently close connection to the conduct the statute prohibits.' '' *Bank of Am. Corp.* v. *City of Miami,* 581 U.S. at 190 (quoting *Lexmark Int'l, Inc.* v. *Static Control Components, Inc.,* 572 U.S. at 133. In the present context, this analysis asks whether the air pollutant emissions have a sufficiently close connection to the endangerment caused by the air pollution.

[117] 80 FR 64531 (October 23, 2015).

[118] *See id.* at 6430–31 (citing ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66496 (December 15, 2009)).

[119] This proposed interpretation of CAA section 111(b)(1)(A) represents a departure from the EPA's previous interpretations of what it means for a source category to ''contribute[] significantly to'' dangerous air pollution. Given this different starting point, the D.C. Circuit's discussion of significance in *American Lung Ass'n,* 985 F.3d 914, 975–77, is inapposite.

in 2010, to 3.7 percent in 2015, and comprising 3 percent of total global emissions by 2022.[120] This relative decline is driven in part by increases in GHG emissions from developing countries that are rapidly electrifying and increasing their energy demands, including through the robust deployment of fossil fuel-fired EGUs—a trend that is likely to persist going forward. Further, many other countries burn much more coal than is utilized by the U.S. power sector. For example, in 2024, China used more than 13 times as much coal as the U.S.[121] Despite the fact that coal use in the U.S. has declined nearly 62 percent from its historic high in 2007,[122] global coal use continues to grow—with 2024 seeing the most coal use ever.[123] Limiting the use of coal and other fossil fuels in U.S. EGUs does not significantly impact global GHG concentrations when other countries continue to increase their use of fossil fuels. The EPA proposes to find that the large and growing share of GHG emissions from international sources strengthens the conclusion that U.S. fossil fuel-fired electricity generation, including U.S. coal use for electricity generation, does not contribute significantly to globally elevated concentrations of GHGs in the atmosphere.[124]

Aside from these relative trends, the percentage contribution of GHG emissions from U.S. fossil fuel-fired EGUs may not be a significant contribution to global GHG concentrations in the atmosphere, particularly given the discretion conferred by the term ''significant.'' The 3 percent contribution figure from 2022 suggests that the risks to public health and welfare attributed to anthropogenic climate change would not be meaningfully different even if the fossil fuel-fired EGU source category were to cease all GHG emissions.

The EPA solicits comment on the proposed determination that GHG emissions from the EGU source category do not ''contribute significantly'' to dangerous air pollution under CAA section 111(b)(1)(A).

C. Conclusion

In conclusion, the EPA is proposing to interpret CAA section 111 to require, or at least authorize the EPA to require, that the EPA must determine that GHG emissions from EGUs contribute significantly to dangerous air pollution as a predicate to regulation of GHG emissions from fossil fuel-fired EGUs. The EPA is further proposing to determine that GHG emissions from fossil fuel-fired EGUs do not contribute significantly to dangerous air pollution. On this basis, the EPA is proposing to repeal all greenhouse gas standards for the power sector, specifically the 2015 NSPS and the CPS.

V. Summary and Rationale of Alternative Proposal

As an alternative to the proposal to determine that fossil fuel-fired EGUs do not contribute significantly to GHG air pollution and to repeal 40 CFR part 60, subparts TTTT, TTTTa, and UUUUb in their entirety on that basis, the EPA is, based on different rationales, proposing to repeal specific portions of these subparts. Those subparts are the emission guidelines for existing fossil fuel-fired steam generating units in 40 CFR part 60, subpart UUUUb; as well as the requirements for coal-fired steam generating units undertaking a large modification and the phase 2 CCS-based requirements for new base load combustion turbine EGUs in 40 CFR part 60, subpart TTTTa.

If the EPA does not finalize the primary proposal, it may finalize this alternative proposal. Under this alternative, the EPA is not reopening the BSER determinations or standards of performance and related requirements for new and reconstructed intermediate load and low load fossil fuel-fired stationary combustion turbines or for phase 1 for new and reconstructed base load fossil fuel-fired stationary combustion turbines. Similarly, under the alternative proposal, the EPA is not reopening the 2015 NSPS or substantive elements of 40 CFR part 60, subpart TTTT. However, the EPA still requests comment on these issues in general and may, if appropriate, engage in further rulemaking at a future date if this alternative proposal is finalized.

A. Summary of Alternative Proposal

The EPA is proposing to determine that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units because it has not been adequately demonstrated and because the costs are not reasonable. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is proposing to determine that the degree of emission limitation in the CPS for long-term coal-fired steam generating units is not achievable. The EPA is proposing to determine that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units because consideration of the energy requirements shows that 40 percent natural gas co-firing in a steam generating unit is an inefficient use of natural gas, as detailed in section V.B.2 of this preamble, particularly compared to use in a natural gas-fired combined cycle EGU. Therefore, the EPA is proposing to repeal the BSER determinations, presumptive standards of performance, and all related requirements in the emission guidelines for existing long-term and medium-term coal-fired steam generating units.

The EPA is additionally proposing to repeal the requirements for existing natural gas- and oil-fired steam generating units because it would be an inefficient use of State resources to develop, submit, and implement State plans solely for natural gas- and oil-fired steam generating units, which comprise a relatively small part of the source category and would contribute few or no emission reductions under the existing emission guidelines. That is, it would not be reasonable for the EPA to require States to prepare plans for existing natural gas- and oil-fired steam generating units if the EPA is repealing the requirements for existing coal-fired steam generating units. Because the EPA would repeal the substantive requirements for all regulated subcategories, it is proposing to repeal the emission guidelines for existing fossil fuel-fired steam generating units in its entirety.

Because the EPA is proposing to determine that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units, the EPA is further proposing to repeal the CCS-based requirements for coal-fired steam generating units undertaking a large modification. Finally, the EPA is proposing to determine that 90 percent CCS is not the BSER for new base load

[120] Calculations based on U.S. EPA, ''Inventory of GHG Sources and Sinks.'' *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks,* and U.S. EPA, ''Global Greenhouse Overview.'' *https://www.epa.gov/ghgemissions/global-greenhouse-gas-overview.*

[121] Institute for Energy Research, ''Global Coal Use Hits Another Historic Record in 2024.'' January 21, 2025. *https://www.instituteforenergyresearch.org/fossil-fuels/coal/global-coal-use-hits-another-historic-record-in-2024/.*

[122] EIA Annual Coal Report 2023 and 2007. *https://www.eia.gov/coal/annual/.*

[123] Institute for Energy Research, ''Global Coal Use Hits Another Historic Record in 2024.'' January 21, 2025. *https://www.instituteforenergyresearch.org/fossil-fuels/coal/global-coal-use-hits-another-historic-record-in-2024/.*

[124] In *American Lung Ass'n,* the D.C. Circuit noted that what it viewed as U.S. power plants' relatively large share of global GHG emissions supported the EPA's view in the 2015 New Source Rule that those power plant emissions were significant. *American Lung Ass'n,* 985 F.3d at 977. Since then, the U.S. power plants' share of global GHG emissions has declined. Most importantly, the EPA is now proposing to interpret ''contribute significantly'' to include policy considerations, as noted above.

combustion turbine EGUs because the EPA is proposing that it has not been adequately demonstrated and the costs are not reasonable. Furthermore, because it is unlikely that infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is proposing to determine that the phase 2 standards of performance in the CPS for new base load combustion turbines are not achievable. Consequently, the EPA is proposing to repeal the phase 2 CCS-based requirements for new base load combustion turbine EGUs.

This section details the rationale for the alternative proposal to repeal the emission guidelines for existing fossil fuel-fired steam generating units, the CCS-based requirements for coal-fired steam generating units undertaking a large modification, and the phase 2 CCS-based requirements for new base load combustion turbine EGUs.

B. Emission Guidelines for Existing Fossil Fuel-Fired Steam Generating Units

1. CCS-Based Requirements for Long-Term Existing Coal-Fired Steam Generating Units

The EPA is proposing to determine that CCS with 90 percent capture is not the BSER for long-term existing coal-fired steam generating units because it has not been adequately demonstrated, and the costs are unreasonable. Furthermore, as detailed in section V.B.1.c of this preamble, it is unlikely that infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, and the EPA is therefore proposing to determine that the degree of emission limitation in the CPS for long-term coal-fired steam generating units is not achievable. Consequently, the EPA is proposing to repeal the requirements in the emission guidelines pertaining to long-term existing coal-fired steam generating units.

a. Adequately Demonstrated

CCS with 90 percent capture involves the capture of 90 percent of the CO_2 from the flue gas of the EGU, transport of the compressed CO_2 via pipeline, and sequestration in geologic storage. The foundation of the EPA's prior BSER determination fails at the first step in the process because 90 percent capture of the CO_2 from flue gas of an EGU has not been adequately demonstrated and should not have been considered or selected as the BSER.

As explained previously, the EPA has discretion under CAA section 111 to determine whether technologies are adequately demonstrated such that they are appropriate for consideration and potential selection as the BSER. In the CPS, the EPA interpreted CAA section 111, its legislative history, and the D.C. Circuit caselaw to take the position that this discretion includes a degree of forward-looking prediction on whether a technology has been ''adequately demonstrated'' such that it could be the BSER for a given source category.[125] The text and structure of CAA section 111 and applicable case law demonstrate, however, that even if the EPA has discretion in this regard, it is not unbounded. The statute requires the EPA to ''review and, if appropriate, revise'' new source standards for a listed category at least every eight years.[126] This provision indicates that technologies requiring enhancements and development that would take significant time, and certainly that would take an entire review cycle or longer, cannot be considered ''adequately demonstrated'' and thus are not appropriate for selection as the BSER. Rather, the EPA should review the state of the technology at the next eight-year review cycle, and consider at that time whether it is ''adequately demonstrated.'' For the reasons detailed in this section of the preamble, the EPA is proposing 90 percent CCS is not adequately demonstrated. As a result, even if the EPA has authority to take into account future technological development in determining adequately demonstrated, and even if 90 percent capture were achievable in the future, additional time would be required for the CCS technology to develop. The EPA proposes to find that it erred in the CPS, and is proposing that 90 percent CCS cannot be BSER, because the CPS record did not demonstrate that CCS technology would develop further so that 90 percent capture is achievable, did not demonstrate the period of time over which the technology would develop, and, by the same token, did not demonstrate that any such development would occur, at minimum, within the next eight years.

In the CPS, the argument that 90 percent capture was adequately demonstrated relied in large part on the operation of amine solvent-based CO_2 capture at Boundary Dam Unit 3. However, between 2014 and 2022, Boundary Dam achieved a total capture efficiency of not more than 63 percent over the course of a calendar year[127] (the timeframe relevant to the emission reduction requirements in the emission guidelines), which is substantially below the 90 percent capture level specified by the BSER. While the EPA had acknowledged the challenges and underperformance of the capture system at Boundary Dam, it asserted that fixes were available or could be made to address those issues. However, many of those fixes were already made, and performance remained below the design capture efficiency. Furthermore, the operating availability of capture systems has been, to date, less than 100 percent. The EPA previously argued that new solvents were available that could capture CO_2 at higher rates to address these gaps, but the experience at Boundary Dam suggests it would be reasonable to anticipate the possibility that those solvents would similarly underperform. Considering these factors, the EPA is proposing to determine that CCS with 90 percent capture is not adequately demonstrated for existing coal-fired steam generating units. The following subsections provide further explanation.

i. Boundary Dam Unit 3

In the CPS, the EPA relied heavily on the operation of carbon capture at the 110 MW coal-fired Boundary Dam Unit 3 (Saskatchewan, Canada) to demonstrate 90 percent capture. CCS at Boundary Dam has been operated since 2014. The unit uses Shell's amine-based CANSOLV® solvent technology to capture CO_2 from the post-combustion flue gas of the coal-fired boiler.[128] Captured CO_2 is then compressed, transported by pipeline, and used for enhanced oil recovery or stored in a saline aquifer at the Aquistore site.[129] While Boundary Dam Unit 3 achieved 89.7 percent capture over a 3-day test early in its operation, longer-term capture levels have been lower.[130] Between 2015 and 2022, Boundary Dam achieved a total capture efficiency of not more than 63 percent in a calendar

[125] 89 FR 39830–32 (May 9, 2024).

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

[127] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[128] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820191.*

[129] Aquistore. *https://ptrc.ca/aquistore.*

[130] SaskPower Annual Report (2015–16). *https://www.saskpower.com/about-us/Our-Company/~/link.aspx?_id=29E795C8C20D48398EAB5E3273C256AD&_z=z.*

year,[131] which is substantially below the 90 percent capture efficiency of the BSER.

This lower total capture efficiency is due to, among other things, the capture system at Boundary Dam Unit 3 typically processing less than all of the flue gas, in part to ''maintain long-term reliable operation.'' [132] Prior to 2023, the CO_2 capture system at Boundary Dam Unit 3 processed up to about 75 percent of the flue gas when operating, with 90 percent CO_2 capture from the processed flue gas when operating.[133] The EPA argued in the CPS that such capture from the majority of the flue gas was supportive of the determination of 90 percent capture from all of the flue gas as adequately demonstrated; however, this does not account for the differences in performance when a system is processing less than all of the flue gas.

Opponents of the CPS argued before the D.C. Circuit that there is a meaningful difference between instances where an emissions control device processes a ''slipstream'' (a portion of the flue gas) and where a control device processes all of the flue gas. They further suggested that the capture efficiencies achieved for a system processing a portion of the flue gas would not be indicative of potential capture efficiencies for a system processing all of the flue gas.[134] In essence, they asserted that processing a portion of the flue gas ''functions reliably because gas pressures and volumes are static and controllable,'' whereas a capture system processing all of the flue gas ''would need to contend with dynamic pressure and volume, shifting as the facility responds to electricity demand.'' [135]

In general, Boundary Dam Unit 3 operates as a base load unit, typically operating at high capacity factors such that the unit experiences less variation in operation than a load-following unit. The CO_2 capture system uses steam and electricity from the host EGU (*i.e.,* integrated steam and power). While reports on Boundary Dam's operation document increases in capture efficiency at reduced throughputs to the CO_2 absorber,[136] it is unclear whether those reductions in throughput coincided with decreases in load of the host EGU in response to changes in demand. Because the flue gas can bypass the CO_2 capture system, it is possible that the throughput to the capture system could be changed independently of the changes in steam load or electricity generation. While other control schemes may be applicable, and it may be that further optimization could be undertaken when processing all of the flue gas,[137] a CO_2 capture system required to process all of the flue gas at all times may not have the same flexibility in process control that is available to a system processing a portion of the flue gas. Regardless, the total capture from the facility has been substantially less than 90 percent.

Around 2024, additional improvements at Boundary Dam Unit 3 were made to increase throughputs, and SaskPower noted that a greater portion of the flue gas was being processed by the capture system (up to 95 percent of the flue gas, with 87 percent capture from the processed flue gas, resulting in 83 percent total capture when operating).[138] Whether that performance has been maintained in the long term has not been reported. Notably, at those higher throughputs, the capture efficiency from the processed flue gas is lower. Moreover, even with those improvements, Boundary Dam continues to operate with capture efficiencies below design specification.

Finally, availability of the capture system at Boundary Dam Unit 3 has been less than 100 percent. Between 2015 and 2022, annual availability of the capture plant relative to the EGU varied between 58 and 94 percent.[139] In 2024, average quarterly availability of the capture plant was about 85 percent.[140] Lower availabilities further contribute to lower total capture efficiencies.

The total capture efficiency at Boundary Dam Unit 3 has been less than 90 percent because the capture system has not processed all of the flue gas, the capture efficiency is still less than 90 percent when the capture system is operating even after applying fixes, and the availability of the capture system is less than 100 percent. Considering this, the EPA is proposing to conclude that the experience at Boundary Dam Unit 3 does not support 90 percent CCS as adequately demonstrated.

ii. CO_2 Capture at Other Coal-Fired Steam Generating Units

To support the prior determination of 90 percent capture as adequately demonstrated, the EPA cited other applications of CCS at coal-fired steam generating units. These included CO_2 capture at the Argus Cogeneration Plant (Trona, California) as well as at AES's Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) plants.[141] In general, these projects were not of an equivalent size to commercial scale or, in the case of the Argus Cogeneration Plant, captured far less than 90 percent of CO_2.

The EPA also cited Energy Policy Act of 2005 (EPAct05) assisted projects including a pilot-scale project at Plant Barry (Mobile, Alabama) and Petra Nova at W.A. Parish Unit 8 (Thompsons, Texas). The 25 MWe (megawatt-equivalent) project at Plant Barry is not reflective of commercial scale operation.

The Petra Nova project began operation in 2017 and was put into reserve shutdown (*i.e.,* idled) in May 2020, citing the poor economics of utilizing captured CO_2 for enhanced oil recovery (EOR) at that time. On September 13, 2023, it was announced that the carbon capture facility at Petra Nova had been restarted.[142] A final report from the National Energy Technology Laboratory (NETL) details the challenges faced by the project over

[131] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[132] SaskPower. ''Docket ID No. EPA–HQ–OAR–2023–0072: SaskPower Correction of Reference to Boundary Dam Unit 3 Emissions Performance in Proposed Rule.'' August 4, 2023. Document ID No. EPA–HQ–OAR–2023–0072–0687.

[133] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[134] *West Virginia* v. *EPA, No. 24–1120* (D.C. Cir. 2024), Doc. #2083273, at 46–47 (Opening Brief of Petitioners).

[135] *Id.*

[136] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[137] *Id.*

[138] U.S. EPA, ''Meeting with SaskPower to Discuss CCS at Boundary Dam Unit 3.'' January 18, 2024. Document ID No. EPA–HQ–OAR–2023–0072–8906.

[139] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[140] SaskPower. BD3 Status Update: Q4 2024. *https://saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q4-2024.*

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

[142] JX Nippon Oil & Gas Exploration Corporation. *Restart of the large-scale Petra Nova Carbon Capture Facility in the U.S.* (September 2023). *https://www.nex.jx-group.co.jp/english/newsrelease/upload_files/20230913EN.pdf.*

an initial 3-year period. These included leaks from heat exchangers, build-up of slurry and solids on the flue gas blower, and build-up of scale on various components.[143] While Petra Nova captured 92.4 percent of the CO_2 from the 240 MWe flue gas it processed over a 3-year period, maintenance to address outages directly attributable to the CO_2 capture facility were about 10 percent of the year on average over that timeframe. Accounting for those outages results in a total capture efficiency less than 90 percent. Furthermore, Petra Nova processes a 240 MWe portion of the flue gas from the 610 MW W. A. Parish Unit 8. At full load, that would equate to a capture efficiency of about 36 percent of the emissions from the coal-fired steam generating unit. Additionally, the 90 percent CCS BSER in the CPS was premised on the CO_2 capture plant using integrated steam and electricity from the host EGU. However, Petra Nova uses an auxiliary natural gas-fired combustion turbine cogeneration unit to provide steam and electricity to the CO_2 capture process and CO_2 emissions from the auxiliary cogeneration unit were not captured. Accounting for emissions from the auxiliary cogeneration unit would lower the capture efficiency further.

It is unclear whether the auxiliary cogeneration unit provided additional operational flexibility in how the capture facility was able to respond to changes in flue gas conditions. Generally, automatic controls will adjust operation of the capture facility (*e.g.,* flue gas blower operation, steam load to the reboiler) in response to changing load and changes in flue gas flowrate and CO_2 concentration.[144] When flue gas CO_2 concentrations are at design levels, the capture facility can maintain design throughput (*i.e.,* on a lb CO_2/hr basis) with the host EGU operating as low as 50 percent load. At lower loads, the capture throughput decreases proportionally. Generally, the capture facility can operate between 50 to 100 percent of its design throughput. However, independent of the capture facility, challenges specific to the auxiliary cogeneration unit (*e.g.,* handling excess steam) were observed below 70 percent design throughput, limiting operation at lower throughputs. Furthermore, the auxiliary cogeneration unit contributed to additional outages (67 days in 2017, 1 day in 2018, and 20 days in 2019).

[143] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[144] *Id.*

iii. Variations in Performance of Capture

The determinations in the CPS assumed that the CO_2 capture system is available every hour the EGU is operational and performs at its design capture efficiency (or better) during each of those hours. The EPA is now proposing to find that it did not adequately account for variations in performance of CO_2 capture that would result in a lower capture efficiency. In the CPS, the EPA did not account for changes in seasonal performance of the capture system. Both Boundary Dam Unit 3 and Petra Nova reported challenges during periods of high heat and humidity. At Boundary Dam Unit 3, ''[t]he third quarter of 2024 (July 1 to September 30) included an abnormally hot and humid summer, resulting in a slightly lower daily average capture of 2,675 [metric tons] per day [. . .].'' [145] For other quarters, daily average capture rates were 2,867 in the second quarter of 2024,[146] 2,484 metric tons per day in the fourth quarter of 2024,[147] and 2,553 metric tons per day in the first quarter of 2025.[148] Reasons for the lower average rate of capture in other quarters was not provided. At Petra Nova, while the target capture rate was maintained, a combination of factors including, ''summer ambient conditions [. . .] resulted in the loss of excess margin in the cooling system stressing the ability to maintain [. . .] capture [. . .].'' [149]

The EPA also did not account for periodic decreases in the performance of the CO_2 capture system due to solvent degradation and fouling of components between maintenance cycles. Boundary Dam Unit 3 experienced challenges with respect to solvent foaming, biological fouling, scaling, and fouling from fly-ash.[150] [151] While actions can be taken to address those issues, performance and capture efficiency would necessarily decrease in between treatments or maintenance (*e.g.,* fouling would steadily accumulate after cleaning). On average, the capture efficiency would therefore be less than optimal. SaskPower indicated that even after applying such fixes, Boundary Dam Unit 3 achieved at best a total capture efficiency of 83 percent when the capture system was operating.[152]

Furthermore, the EPA did not adequately account for periods of startup on the availability of the capture system and only provided a qualitative rationale for why its approach was reasonable.[153] After absorption, thermal energy (heat) in the form of steam is required to release the CO_2 from the CO_2-rich solvent and electricity is required to power the compressor to compress the CO_2 for transport via pipeline. However, prior to substantial production of steam and electricity, major components of the capture process may be offline. The EPA cited unspecified process techniques to address the availability of the capture system at startup.[154] Even assuming the capture system could consistently capture 90 percent CO_2 when operating, any CO_2 emitted prior to operation of the capture equipment would necessarily result in the average capture efficiency being less than 90 percent.

To consistently achieve 90 percent capture on average, the source would have to overperform during certain hours. The EPA cited results from Boundary Dam [155] that suggested higher capture efficiencies were achieved at lower throughputs. However, in its justification of the BSER, the EPA relied on an assumption that sources would be operating at high capacity throughout the course of the year. If that were the case, the hypothetical higher capture efficiencies potentially achieved at lower throughputs would not be observed when the CO_2 capture system is operated in practice. To otherwise achieve an annual average capture

[145] SaskPower. BD3 Status Update: Q3 2024. *https://www.saskpower.com/about-us/our-company/blog/2024/bd3-status-update-q3-2024.*

[146] SaskPower. BD3 Status Update: Q2 2024. *https://www.saskpower.com/about-us/our-company/blog/2024/bd3-status-update-q2-2024.*

[147] SaskPower. BD3 Status Update: Q4 2024. *https://saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q4-2024.*

[148] SaskPower. BD3 Status Update: Q1 2025. *https://saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q1-2025.*

[149] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[150] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820191.*

[151] Pradoo, P., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286503.*

[152] U.S. EPA, ''Meeting with SaskPower to Discuss CCS at Boundary Dam Unit 3.'' January 18, 2024. Document ID No. EPA–HQ–OAR–2023–0072–8906.

[153] 89 FR 39854 (May 9, 2024).

[154] U.S. EPA, Response to Comments Document, April 2024. Chapter 4.1.5, page 33. Document ID No. EPA–HQ–OAR–2023–0072–8914.

[155] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

efficiency of 90 percent, higher instantaneous capture efficiencies would likely need to be achievable. In the CPS, the EPA cited vendor statements of pilot tests for different commercial amine solvents where higher capture efficiencies were observed under specific conditions,[156] although those capture rates have not been demonstrated at the commercial scale over the course of a calendar year. Regardless, the experience at Boundary Dam has shown that it would be reasonable to anticipate that total capture efficiencies achieved in practice would be less than design specifications.

iv. Projects and Technologies in Development

There are no new post-combustion CCS applications in operation that are achieving 90 percent capture over the course of a calendar year at commercial scale. Rather, some of the planned projects cited in the CPS either have been abandoned or have faced other challenges. Project Diamond Vault was a planned project to capture up to 95 percent of CO_2 emissions from the 600 MW Madison Unit 3 at Brame Energy Center in Lena, Louisiana.[157] The Front-End Engineering Design (FEED) study and current plans for carbon capture were abandoned in late 2024.[158] Project Tundra is a carbon capture project in North Dakota at the Milton R. Young Station lignite coal-fired power plant. The plan has been for the capture plant to treat the flue gas from the 455 MW Unit 2 and some additional flue gas from the 250 MW Unit 1 (an equivalent capacity of 530 MW in total).[159] TC Energy, a primary sponsor of Project Tundra, has since withdrawn from the project, although the project may continue to move forward depending on various factors.[160] The timeframes for several other CCS projects on coal-fired EGUs are unclear.[161]

Finally, the EPA based its prior determination on the assessment of CO_2 capture using an amine solvent. While other technologies may be applied for post-combustion CO_2 capture (membranes, molten salts, cryogenic methods), they are in general less developed and have yet to be applied at large scale. Some, such as membranes, while achieving lower capture efficiencies (closer to 70 percent for membranes), could have the benefit of fewer byproduct emissions and potentially lower water and/or energy requirements (process steam for heating) in comparison to amine solvent technologies.[162] The EPA notes that higher capture efficiencies of 90 percent could otherwise complicate commercial deployment of those other technologies.

b. Cost

The EPA has re-evaluated the costs and associated assumptions underlying the cost analysis of 90 percent CCS on existing long-term coal-fired steam generating units and is proposing to determine that the costs are not reasonable. In the CPS, costs for CCS on existing coal-fired steam generating units were determined assuming a best-case scenario. Specifically, the cost assessment assumed sources operated at high annual capacity factors (80 percent) and that the CO_2 capture equipment was available and performing optimally every hour the EGU was operating. However, as detailed in the preceding section of this document, even with a design capture efficiency of 90 percent, the effective annual capture efficiency is lower, and under some circumstances significantly lower. Moreover, in 2023, coal-fired EGUs had an average capacity factor of 42 percent.[163] Lower capacity factors typically result in less revenue from electricity generation. Additionally, less CO_2 captured (lower actual capture efficiency, lower EGU capacity factor, or both) results in higher costs due to reduced revenue from the IRC section 45Q tax credit.

In the CPS, the costs of CCS for existing coal-fired steam generating units accounted for the IRC 45Q tax credit by reducing the direct costs to the source for every ton of CO_2 reduced, and costs were assessed over a period consistent with the 12-year availability of the IRC section 45Q tax credit. Additionally, rather than directly considering the costs for any operation after the expiration of availability of the IRC section 45Q tax credit for existing coal-fired steam generating units in the CPS, the EPA committed to review the requirements of the emission guidelines pertaining to existing coal-fired steam generating units by January 1, 2041, and posited that other mechanisms for potential valuation of EGUs operating with 90 percent CCS could arise in the future.[164] However, those assumptions are no longer reasonable because the EPA believes that coal-fired steam generating units are now more likely to operate longer than they will be able to claim the tax credit.

Under a more realistic set of assumptions that reflect, among other things, lower capacity factors and the limited availability of the IRC section 45Q tax credit,[165] the costs are substantially higher ($53.7/MWh, $77/ton of CO_2 reduced) than those determined in the CPS and more than two times higher on a $/MWh basis than the costs the EPA has previously determined to be reasonable ($18.50/MWh).[166] Such high costs, particularly on a $/MWh basis, are not reasonable and do not support 90 percent CCS as BSER. Additionally, parties that challenged the CPS in the D.C. Circuit argued that the tax credit shifts the costs of CCS to taxpayers and that the EPA failed to account for those costs.[167] The EPA proposes that this type of cost calculation is an incorrect accounting for the costs of control as the EPA should not be considering tax credits when determining the cost of the control and is specifically taking comment on this position. Additionally, companies finance cost of controls in various different ways (*e.g.,* debt financing), and can obtain different interest rates that are historically not individually calculated when developing regulations. Moreover, legislation has been introduced in

[156] 89 FR 39852 (May 9, 2024).

[157] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[158] Cleco Corporate Holdings, LLC SEC Form 10Q, at 51 (August 18, 2024). *https://www.sec.gov/Archives/edgar/data/18672/000108981924000026/cnl-20240630.htm.*

[159] ''An Overview of Minnkota's Carbon Capture Initiative—Project Tundra,'' 2023 LEC Annual Meeting, October 5, 2023.

[160] Power Engineering. Key partner withdraws from large-scale CO2 capture project. *https://www.power-eng.com/environmental-emissions/carbon-capture-storage/key-partner-withdraws-from-large-scale-co2-capture-project/.*

[161] Inside Climate News. A Carbon Capture Project Faces a New Delay in a Year of Slow Progress for Coal Power Plants Looking for Retrofits. *https://insideclimatenews.org/news/10122024/north-dakota-coal-plant-carbon-capture-project-faces-new-delay/.*

[162] Merkel, Tim, *et al.* ''Commercial-Scale Front-End Engineering Design (Feed) Study for MTR's Membrane CO2 Capture Process.'' November 2022. *https://www.osti.gov/biblio/1897679.*

[163] U.S. Energy Information Administration. Electric Power Annual. *https://www.eia.gov/electricity/annual/.*

[164] 89 FR 39902 (May 9, 2024).

[165] Capital equipment, *etc.,* consistent with 90 percent design capture rate, 75 percent actual capture rate, a fixed 40 percent capacity factor, and 15-year booklife (12 years of 45Q availability, 3 years without). Costs are expressed in 2019$. See memorandum *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units,* available in the docket.

[166] Costs are expressed in 2019$. In a variety of rulemakings, the EPA has required coal-fired EGUs to install and operate flue gas desulfurization (FGD, or wet scrubbers) to reduce their SO_2 emissions. The annualized cost of installing these controls on a representative 700 to 300 MW coal-fired steam generating unit are $14.80 to $18.50/MWh. Hence control costs that are generally consistent with these values should be considered reasonable. 89 FR 39882 (May 9, 2024).

[167] *West Virginia* v. *EPA, No. 24–1120* (D.C. Cir. 2024), Doc. #2083273, at 79–89.

Congress to repeal the IRC section 45Q tax credit,[168] so that owners/operators cannot be assured that it will be available for purposes of compliance with the CPS. The costs of 90 percent CCS are not reasonable without taking into account the tax credit.

c. Infrastructure

The CPS determined that the capture, pipeline, and sequestration infrastructure necessary for the affected sources to meet the standards could be deployed by the compliance date of January 1, 2032. However, that position relied on the assumption of best-case scenarios. The equipment for the capture of CO_2 takes time to design, permit, and install. In the CPS, the Agency assumed an aggressive timeline for deployment of capture equipment. Of the project schedules in a report developed by Sargent and Lundy,[169] the EPA based the timeline for installation of capture equipment off the more aggressive schedule that included a 12-month FEED study in place of an 18-month FEED study. The EPA further abbreviated that schedule by 2 months based on its own assumptions by shortening the duration for commercial arrangements from 9 months to 7 months, assuming sources immediately begin sitework as soon as permitting is complete, and accounting for 13 months (rather than 14) for startup and testing.[170] However, those assumptions may not reflect what is achievable for the average source, and those assumptions furthermore ignore any potential delays. Regarding transport of CO_2, there is not an existing network of CO_2 pipelines with the capacity capable of meeting the demands in the CPS. While there are about 5,000 miles of CO_2 pipelines operational in the U.S.,[171] they are largely not located near existing coal-fired sources. Planned CO_2 pipelines continue to face delays due to factors including State permitting and the challenges associated with eminent domain authority and negotiating rights-of-way. Summit Carbon Solutions' application for a pipeline in South Dakota was paused after the State banned eminent domain for CO_2 pipelines.[172] [173] A similar law is progressing through the Iowa State legislature.[174] Furthermore, while the U.S. has broad availability of the geologic formations that may potentially be suitable for CO_2 sequestration, existing storage infrastructure for sequestration of CO_2 is limited. In the CPS, the EPA based its assumptions on the availability of "potential" storage sites; however, it takes time to characterize those sites, and it is possible that the nearest available "potential" site may not ultimately be suitable. Development of planned storage sites may also face delays due to permitting and other issues. Considering these factors, it is unlikely that infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, and the EPA is therefore proposing that the degree of emission limitation in the CPS for long-term coal-fired steam generating units is not achievable.

d. Conclusion

Because the EPA is proposing to find that 90 percent CCS is not an adequately demonstrated system of emission reduction and that the cost of 90 percent CCS for long-term coal-fired steam generating units is not reasonable, it is proposing to determine that 90 percent carbon capture and storage is not BSER for long-term coal-fired steam generating units. Furthermore, because it is unlikely that infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is proposing to determine that the degree of emission limitation in the CPS for long-term coal-fired steam generating units is not achievable. Consequently, the EPA is proposing to accordingly repeal the requirements in emission guidelines pertaining to long-term coal-fired steam generating units. In this proposed repeal, the EPA is addressing only CCS with 90 percent capture, because that was the BSER determination in the CPS. Whether CCS with other, lower rates of capture could be the BSER is outside the scope of this repeal action.

The EPA solicits comment on the arguments for repealing the 90 percent CCS-based requirements of the emission guidelines pertaining to long-term coal-fired steam generating units. The EPA solicits comment on its proposed conclusion that 90 percent CCS is not an adequately demonstrated system of emission reduction. In particular, the EPA is requesting input on its proposal that the performance of the CO_2 capture system at Boundary Dam Unit 3 is not a sufficient basis for determining that 90 percent CCS is adequately demonstrated for coal-fired steam generating units. The Agency further solicits comment on the status and performance of CCS projects and technologies more generally, especially on projects that inform the question of whether 90 percent CCS is adequately demonstrated. The EPA is also requesting comment on its proposed conclusions regarding the impacts of startup and of variability more generally on CCS performance, as well as on methods to control process parameters (pressure, velocity, *etc.*) and capture efficiencies under startup and variable load, and what differences in those methods exist where the CO_2 capture system processes all or part of the flue gas.

The EPA also solicits comment on its proposed conclusion that the cost of 90 percent CCS for long-term coal-fired steam generating units is not reasonable, including on any considerations related to taking the IRC section 45Q tax credit into account when calculating the costs of CCS in the context of a BSER analysis. The EPA further requests comment on the costs of CCS for existing coal-fired steam generating units, including on the interplay of design capture efficiency, actual capture efficiency, and cost effectiveness.

The EPA also solicits comment on its proposed determination that, because the infrastructure for CCS is unlikely to be deployed by the January 1, 2032 compliance date, the degree of emission limitation is not achievable for long-term coal-fired steam generating units.

2. Natural Gas Co-Firing-Based Requirements for Existing Medium-Term Coal-Fired Steam Generating Units

The EPA is proposing to determine that 40 percent natural gas co-firing is not the BSER for medium-term coal-fired steam generating units. As part of determining the BSER, the EPA takes into account energy requirements.[175] As discussed in section III.A. of this preamble, energy requirements may include the impacts, if any, of the air pollution controls on the source's own energy needs. The EPA may further assess energy requirements as they pertain to the energy system as a whole, on a sector-wide, regional, or national

[168] 119th Congress. H.R.1946—45Q Repeal Act of 2025. *https://www.congress.gov/bill/119th-congress/house-bill/1946/text.*

[169] CO_2 Capture Project Schedule and Operations Memo, Sargent & Lundy (2024). Document ID EPA–HQ–OAR–2023–0072–9095, Attachment 17.

[170] 89 FR 39875 (May 9, 2024).

[171] Congressional Research Service. 2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June 3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[172] South Dakota Public Broadcasting. Summit pauses CO2 pipeline application in South Dakota. *https://www.sdpb.org/business-economics/2025-03-12/summit-pauses-co2-pipeline-application-in-south-dakota.*

[173] South Dakota Legislature House Bill 1052. *https://sdlegislature.gov/Session/Bill/25581.*

[174] Iowa Capital Dispatch. House votes to ban eminent domain for CO2 pipelines. *https://iowacapitaldispatch.com/2025/03/26/house-votes-to-ban-eminent-domain-for-co2-pipelines/.*

[175] CAA section 111(a)(1).

basis, as appropriate. In the ACE Rule, the EPA concluded that natural gas co-firing in a coal-fired steam generating unit, particularly in high proportions, is an inefficient use of natural gas.[176] While coal-fired steam generating units may use small amounts of natural gas for startup purposes, relatively few use natural gas in proportions that would have been consistent with the requirements for medium-term coal-fired steam generating units in the CPS. The higher hydrogen content of natural gas relative to coal reduces the efficiency of the boiler; 40 percent natural gas co-firing would result in a decrease in the boiler efficiency by about 2 percent (to a total efficiency less than 40 percent). In the CPS, the EPA argued that this decline in efficiency could be partially offset by decreases in auxiliary power demand related to coal handling and emissions controls but acknowledged that there was uncertainty about whether this would be true in all circumstances.[177] The EPA explained that the determination in the ACE Rule that natural gas co-firing was an inefficient use of gas was informed by the more limited supply of natural gas and the larger amount of coal-fired EGU capacity and generation that were present when that rule was promulgated in 2019 relative to when the CPS was finalized. The CPS rationale went on to say that, since the expected supply of natural gas had expanded since 2019 and the capacity and generation of existing coal-fired EGUs had decreased, the total mass of natural gas that might be required to implement co-firing could be reduced to reasonable levels.[178]

The EPA now proposes to find the reasoning in the CPS regarding the availability of natural gas and the demand that would be associated with 40 percent co-firing natural gas in coal-fired steam boilers to be an insufficient basis for determining there would be no significant adverse consequences related to energy requirements. The EPA believes that coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply; a number of coal-fired steam generating units are delaying or canceling their scheduled retirements in light of increasing electricity demand.[179] Additionally, the U.S. Energy Information Administration (EIA) projects that the demand for natural gas, driven by domestic consumption and liquefied natural gas exports, will grow both in the near term[180] as well as in the long term.[181] Thus, it is not reasonable to assume that the total volume of natural gas that would be needed to implement co-firing would be reduced in the CPS relative to what the EPA expected in 2019 or that diverting that natural gas from other uses would have no significant adverse impacts on the energy system. Furthermore, the fact remains that natural gas may be more efficiently used in natural gas-fired combined cycle EGUs. New natural gas-fired combined cycle EGUs generally have operating efficiency of greater than 50 percent. For base load units, heat rates in new natural gas-fired combined cycle EGUs are approximately 6,700 Btu/kWh whereas heat rates in existing 100 percent natural gas-fired steam generating units can be more than about 11,000 Btu/kWh. The use of large amounts of natural gas for combustion in combined cycle EGUs is more efficient. Considering the energy requirements, the EPA is proposing that 40 percent natural gas co-firing is not a suitable BSER for existing coal-fired steam generating units. The EPA solicits comment on its proposed repeal of the 40 percent co-firing BSER. In particular, the Agency requests input on considerations related to the supply of and demand for natural gas, and on how the diversion of natural gas to coal-fired steam generating units would impact the energy system. The EPA additionally requests any information related to the relative efficiency of co-firing natural gas versus using it in a combustion turbine to generate electricity.

Additionally or in the alternative, the EPA proposes to find that 40 percent co-firing with natural gas is not the BSER for existing medium-term coal-fired steam generating EGUs because it constitutes generation shifting and is therefore beyond the EPA's authority to require under CAA section 111.[182] While the EPA considered whether co-firing natural gas in a coal-fired boiler would constitute generation shifting in the CPS and concluded that it would not,[183] the Agency has reexamined the question and is now proposing to find that a requiring a utility to use a completely different fuel type that in many cases requires significant new infrastructure to be added to supply the facility, and can require modification/addition of burners to the boiler, is impermissible generation shifting. The parties that challenged the validity of the CPS in the D.C. Circuit similarly distinguished fuel switching between the same type of fuel (*e.g.,* switching from high-sulfur coal to lower sulfur-coal) from fuel switching between different types of fuel (*e.g.,* switching from coal to gas in a steam generating boiler)[184] and argued that the latter runs afoul of the Supreme Court's decision in *West Virginia*[185] that the EPA cannot base BSER on shifting generation. Similarly, the EPA proposes to find that a BSER based on forcing a coal-fired EGU to become a partially natural gas-fired steam generating units shifts that unit's generation from coal to natural gas and is impermissible under the Court's precedent because it is an attempt to dictate the market share of coal versus natural gas. The EPA requests comment on its proposed conclusion that 40 percent natural gas co-firing cannot be the BSER for a coal-fired steam generating units because it constitutes generation shifting.

Finally, the EPA proposes to determine that a degree of emission limitation based on 40 percent natural gas co-firing is not achievable because it is unlikely that the pipeline infrastructure necessary can be deployed by the compliance date of January 1, 2030. In the CPS, the EPA estimated that the maximum aggregate amount of pipeline capacity needed to implement 40 percent natural gas co-firing would be nearly 14.7 billion cubic feet per day, which would require about 3,500 miles of pipeline.[186] The CPS further assumed that sources could obtain the permits necessary to construct these pipelines in one year and that the actual construction would take one year or less.[187] While the EPA's timelines were based on average permitting, approval, and construction timeframes,[188] the EPA now believes that projects facing reasonably foreseeable adverse conditions could take longer (up to 5 years for approval

[176] 84 FR 32545 (July 8, 2019).

[177] 89 FR 39895 (May 9, 2024).

[178] *Id.*

[179] Power. U.S. Coal Plants Get Reprieve as Market and Policies Change. *https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change/.*

[180] U.S. Energy Information Administration. EIA expects higher wholesale U.S. natural gas prices as demand increases. *https://www.eia.gov/todayinenergy/detail.php?id=64344.*

[181] U.S. Energy Information Administration, Annual Energy Outlook 2025. *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2025&cases=ref2025&sourcekey=0.*

[182] *West Virginia* v. *EPA, No. 24–1120* (D.C. Cir. 2024), Doc. #2083273, at 110–14.

[183] U.S. EPA, Response to Comments Document, April 2024. Chapter 2.7.2, page 101–02. Document ID No. EPA–HQ–OAR–2023–0072–8914.

[184] *Id.* at 112–13.

[185] 597 U.S. 697 (2022).

[186] 89 FR 39893 (May 9, 2024).

[187] *Id.* n.682.

[188] 89 FR 39893 (May 9, 2024).

and construction).[189] Further, the Agency did not consider that these projects would be undertaken in addition to projects necessary to meet the increasing demand for natural gas for other purposes. Because the EPA now believes that these factors, among potentially others, make it unlikely that the necessary additional pipeline infrastructure for 40 percent natural gas co-firing can be deployed by the January 1, 2030, compliance date, it is proposing to determine that the degree of emission limitation in the CPS for medium-term coal-fired steam generating EGUs is not achievable. The EPA solicits comment on this proposed determination.

For these reasons, the EPA is proposing to repeal the requirements of the emission guidelines pertaining to medium-term coal-fired steam generating units. In this action, the EPA is addressing specifically 40 percent co-firing, because that was the BSER determination in the CPS. Whether co-firing at other percentages could be the BSER is outside the scope of this action.

3. Requirements for Existing Natural Gas- and Oil-Fired Steam Generating Units

As noted above, in the CPS, the EPA finalized routine methods of operation and maintenance as the BSER for intermediate load and base load natural gas- and oil-fired steam generating units, and uniform fuels as the BSER for low load natural gas- and oil-fired steam generating units. Because those BSERs were consistent with what most sources were already doing (*i.e.,* business-as-usual), there was no additional cost associated with them, and they resulted in a degree of emission limitation that would have resulted in few, if any, emission reductions for any of the units.

In 2023, natural gas and oil-fired steam generating units accounted for 1.2 percent of total electric generation in the U.S. and 3.5 percent of power sector CO_2 emissions in the U.S.[190] This share of both generation and emissions in the U.S. is projected to decrease even further over the forecast period as outlined by the EPA's projections of power sector behavior using the Integrated Planning Model (IPM) in the Summer 2023 Reference Case.[191]

Thus, natural gas- and oil-fired steam generating units represent a very small portion of the source category from both a generation and an emissions perspective. Moreover, the business-as-usual BSERs and presumptive standards finalized in CPS would result in little to no emission reductions. While the EPA is not proposing to find the BSERs or presumptive standards in the CPS unreasonable or inappropriate for these sources, the Agency believes it would be imprudent to require States to develop State plans solely for these units. The development of State plans involves a meaningful expenditure of resources by States and regulated entities, including time and money for development of engineering analyses, for conducting public hearings and meaningful engagement, for drafting permits or other legal instruments, and for getting necessary legislative or other approvals.[192] At this time, requiring States to expend resources to develop plans to regulate just these sources would be unduly burdensome from an administrative standpoint given that such plans would most likely have no significant benefit. Thus, the EPA is proposing to repeal the requirements of the emission guidelines pertaining to natural gas- and oil-fired steam generating units. The EPA solicits comment on the arguments for repealing the requirements of the emission guidelines pertaining to natural gas- and oil-fired steam generating units.

4. Conclusion

Because the EPA is proposing to repeal the BSER determinations and related requirements for existing long-term and medium-term coal-fired steam generating units and is further proposing to repeal the requirements for existing oil- and natural gas-fired steam generating units, the Agency is proposing to repeal the emission guidelines for steam generating units in 40 CFR part 60, subpart UUUUb, in their entirety.

C. CCS-Based Requirements for Coal-Fired Steam Generating Units Undertaking a Large Modification

In the CPS, the EPA finalized revisions to the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.,* a modification that increases its hourly emission rate by more than 10 percent) to be consistent with the 90 percent CCS requirements for existing coal-fired steam generating units. As discussed in section V.B.1 of this preamble, the EPA is proposing to find that 90 percent CCS is not an adequately demonstrated system of emission reduction and that the cost of 90 percent CCS is not reasonable. For these reasons, the EPA is also proposing to repeal the CCS-based standards of performance for coal-fired steam generating units undertaking a large modification. The EPA solicits comment on its rationale for repealing the CCS-based standards of performance for coal-fired steam generating units undertaking a large modification.

D. Phase 2 CCS-Based Requirements for New Combustion Turbine EGUs

The EPA is proposing to determine that CCS with 90 percent capture is not the phase 2 BSER for base load combustion turbine EGUs because it has not been adequately demonstrated and the costs are not reasonable. Furthermore, because it is unlikely that infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is proposing to determine that the phase 2 standards of performance in the CPS for new base load combustion turbines are not achievable. Consequently, the EPA is proposing to repeal the phase 2 standards for base load combustion turbine EGUs.

1. Adequately Demonstrated

For many of the same reasons described in section V.B.1.a of this preamble, CCS with 90 percent capture has not been adequately demonstrated for new combustion turbine EGUs. In the CPS, the 90 percent CCS BSER for new base load combustion turbines was based on the same CO_2 capture technology as the 90 percent CCS BSER for existing coal-fired steam generating units. As evidence to support 90 percent CCS on new combustion turbine EGUs as adequately demonstrated in the CPS, the EPA relied on translation of the experience of amine-based capture at coal-fired EGUs. However, as noted in section V.B.1.a of this preamble, the EPA has re-assessed the evidence and is proposing to determine that 90 percent CCS has not been adequately demonstrated for existing coal-fired steam generating units. Therefore, the record for CCS on existing coal-fired steam generating units also does not support 90 percent CCS as adequately demonstrated for new base load combustion turbine EGUs. In the CPS, it was argued that fewer contaminants (particulates, trace metals, SO_2) in the post-combustion flue gas of natural gas-fired stationary combustion turbines

[189] *Documentation for the Lateral Cost Estimation* (2024), *ICF International,* p. 42. Attachment to *Greenhouse Gas Mitigation Measures for Steam Generating Units.* Document ID No. EPA–HQ–OAR–2023–0072–9095.

[190] Based on eGRID2023 data. *https://www.epa.gov/egrid/detailed-data.*

[191] EPA 2023 Summer Reference Case. *https://www.epa.gov/power-sector-modeling/2023-reference-case.*

[192] The EPA's Information Collection Request analysis for the emission guidelines promulgated in the CPS indicates that developing State plans (and negative declarations) would entail a collective cost to the 48 States subject to the rule of approximately $35 million over 3 years. See Document ID No. EPA–HQ–OAR–2023–0072–8836.

would result in fewer challenges than those experienced with CO_2 capture at coal-fired steam generating units. However, the exhaust gas composition for natural gas-fired combustion turbines is different in other ways than for coal-fired (*i.e.,* lower CO_2 concentrations and higher oxygen concentrations), that make CO_2 capture more challenging. Furthermore, combustion turbines are able to change loads more rapidly and start and stop more frequently than coal-fired steam generating units. These factors could create additional challenges for operating CO_2 capture equipment, and demonstrated capture rates from coal-fired EGUs do not necessarily demonstrate that the same capture rates could be achieved from base load combustion turbines. For example, the startup of the CO_2 system may be slower than the startup of a combined cycle combustion turbine EGU, so that CO_2 emitted during startup may not be captured. The examples of CO_2 capture applied directly on combustion turbine EGUs also do not support a conclusion that 90 percent capture has been adequately demonstrated. Primarily, there have been limited examples of applications of CCS to combustion turbine EGUs and none of them have been at sufficient scale to demonstrate a 90 percent total capture rate, which is the specified BSER.

In the CPS, the argument that 90 percent capture was adequately demonstrated at combustion turbine EGUs relied in part on the capture plant at the Bellingham combined cycle turbine. This capture plant was only 40 MWe, processing only approximately 10 percent of the maximum flue gas volume and smaller than most combined cycle turbine EGUs that would have potentially been subject to the requirements of the rule. Particularly considering the relatively small portion of flue gas processed, it is plausible that the amount of flue gas processed by the capture system was controlled independent of changes in load of the host EGU. As noted in section V.B.1.a.i of this document, carbon capture systems with integrated steam and power that are required to process all of the flue gas at all hours may not have the same flexibility in process control that is available to capture systems processing a portion of the flue gas. The EPA otherwise cited pilot studies,[193] but such short-duration demonstrations may not be subject to the same variations in conditions that occur at scale. Furthermore, the experience at Boundary Dam Unit 3 shows that it is reasonable to anticipate that larger scale deployments of CO_2 capture solvent technologies may underperform. The EPA also cited planned projects, but those yet-to-be-operational projects do not show that 90 percent CCS has been adequately demonstrated. The EPA also noted the NET Power Cycle as a potential technology for meeting the standard based on 90 percent capture. However, that technology has yet to be operated at scale and a planned project is facing delays.[194] Similarly, none of the other projects that the EPA cited have yet commenced construction, either on new NGCC units or on retrofits to existing plants. Considering these factors, the EPA is proposing to determine that the record does not support the conclusion that CCS with 90 percent capture has been adequately demonstrated for new base load combustion turbine EGUs.

2. Cost

The EPA has re-evaluated the costs and associated assumptions underlying the cost analysis of 90 percent CCS on new base load combustion turbines and is proposing to determine that the costs are not reasonable. As part of the phase 1 BSER analysis for combustion turbines, the EPA reviewed the performance and costs of efficient generation for combustion turbines with base load ratings ranging from 490 to 6,100 MMBtu/h. Based on the phase 1 BSER analysis, the EPA established higher emission standards for base load turbines with base load ratings of less than 2,000 MMBtu/h. However, when evaluating the phase 2 BSER based on the use of CCS, the EPA based the cost effectiveness presented in the preamble only on combustion turbines with base load ratings of 4,600 and 6,100 MMBtu/h.[195] The costs of the capture equipment and the costs to transport and store the capture CO_2 increase on a $/ton basis for smaller base load combustion turbines. The costs of control on a $/MWh and $/ton basis for the smaller model combustion turbine facilities used in the phase 1 analysis are approximately double the highest costs the EPA reported in the technical support document. The estimated compliance costs for the primary case for the 490 and 1,000 MMBtu/h model combined cycle plants are $73/MWh and $220/tonne and $55/MWh and $160/tonne, respectively, which are significantly higher than the highest costs presented in the CPS—$19/MWh and $63/tonne.[196] Consequently, the EPA is now proposing to find that, in the CPS, it did not establish that the cost of 90 percent CCS is reasonable for smaller base load combustion turbines.

Even without factoring in the previously cited omissions, the primary costs of 90 percent CCS for combustion turbines were a best-case scenario.[197] As described in section V.B.1 of this preamble, the EPA assumed in the CPS that capture equipment has 100 percent availability. Reducing the availability of the capture equipment to 75 percent increases the compliance cost by approximately $2/MWh and $20/tonne ($18/ton) compared to the estimated compliance costs presented in the CPS.[198] These costs exceed the thresholds the EPA cited as reasonable in previous Agency rulemakings.

In addition, when conducting the BSER analysis the Agency assumed the long term capacity factors of new combined cycle turbines would be the same as historical long term capacity factors with and without CCS (51 percent). In the primary policy case, the EPA compared the costs and emissions impacts assuming a new combined cycle turbine with CCS operates at an 80 percent capacity factor for the first 12 years and a 31 percent capacity factor for the next 18 years. The EPA compared the levelized cost of electricity of this model facility to a combined cycle without CCS that operates at a 63 percent capacity factor for the first 12 years, a 47 percent capacity factor for the next 13 years, and a 37 percent capacity factor for the final 5 years. However, the EPA did not use an energy market model to perform a dispatch analysis to support the capacity factors used in the CPS costing analysis. Assuming the full value of the

[193] 89 FR 39927 (May 9, 2024).

[194] Net Power, ''Net Power Reports Fourth Quarter 2024 Results and Provides Business Update.'' March 10, 2025. *https://ir.netpower.com/resources/press-releases/detail/37/net-power-reports-fourth-quarter-2024-results-and-provides.*

[195] The technical support document titled *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* included estimated compliance costs for combined cycle turbines with base load ratings of 2,400 and 3,400 MMBtu/h in figures 11 through 13. The compliance costs for the primary case are $29/MWh and $95/tonne and $22/MWh and $75/tonne respectively—approximately 50 percent higher than the costs presented in the CPS. Document ID No. EPA–HQ–OAR–2023–0072–9099.

[196] See memorandum *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at New and Reconstructed Natural Gas-Fired Combustion Turbine Electric Generating Units,* available in the docket.

[197] The EPA discussed multiple advances that could lower the compliance costs of a BSER based on the use of CCS but none of the technologies are currently commercially available.

[198] See memorandum *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at New and Reconstructed Natural Gas-Fired Combustion Turbine Electric Generating Units,* available in the docket.

IRC section 45Q tax credit, the incremental generating costs of combined cycle turbines with carbon capture are generally higher than those of nuclear EGUs but lower than those of coal-fired EGUs without carbon capture. While the capacity factors of nuclear EGUs are higher than the 80 percent used by the Agency, the recent capacity factors of coal-fired EGUs are much lower, calling into question the capacity factors used by the Agency. Furthermore, even accounting for the full value of the IRC section 45Q tax credit, the estimated incremental generating costs of the 490 MMBtu/h combined cycle turbine with carbon capture are higher than the incremental generating costs of the model plant without CCS. Additionally, during periods when the IRC section 45Q tax credit is not available, it is unlikely that combined cycle turbines with carbon capture would operate at the 31 percent capacity factor used in the CPS costing analysis. The incremental generating costs of all the model combined cycle turbines with carbon capture exceed the incremental generating costs of simple cycle turbines. Simple cycle turbines generally operate at capacity factors of less than 10 percent. Considering that a dispatch modeling analysis would likely result in lower capacity factors and higher compliance costs that further do not support 90 percent CCS as cost reasonable.

As noted above in connection with the costs of CCS for existing coal-fired plants, in the CPS, the IRC section 45Q tax credits were accounted for by reducing the direct costs to the source for every ton of CO_2 captured. However, the EPA no longer believes that accounting for tax credits in determining BSER is appropriate, as discussed in section V.B.1.b of this preamble. Additionally, petitioners of CPS argued that the tax credit shifts the costs of CCS to taxpayers and that EPA failed to account for those costs. If the availability of the tax credit is not accounted for by reducing the costs to sources of implementing 90 percent CCS, then the costs of this system of emission reduction are clearly unreasonable.

3. Infrastructure

Consistent with the arguments presented in section V.B.1.c of this preamble regarding CCS infrastructure for existing coal-fired steam generating units, there is also limited infrastructure available to meet the requirements for the phase 2 CCS-based requirements for base load combustion turbines. While new combustion turbines do not have the additional timeline requirement of State plan development, the timeline in the CPS for the design, permitting, and installation of capture, pipelines, and sequestration for new combustion turbines assumes a best-case scenario. Furthermore, pipeline and sequestration infrastructure remain limited. In the CPS, the EPA argued that new combustion turbines could site preferentially near potential storage sites. However, this did not consider the availability of sufficient quantities of natural gas or the availability of sufficient transmission capacity to transmit power to end users for new base load combustion turbines specifically located near potential storage sites.[199] The analysis also ignores the associated line loss[200] (*i.e.,* inefficiency) due to potentially longer transmission lines and further ignores the requirements of siting electricity generating sources in locations necessary to meet local grid reliability considerations. Considering these factors, it is unlikely that infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, and the EPA is therefore proposing to determine that phase 2 standards of performance in the CPS for new base load combustion turbines are not achievable.

4. Conclusion

The EPA is proposing to determine that 90 percent CCS has not been adequately demonstrated nor shown to have reasonable costs and is not the second component of BSER for base load stationary combustion turbines. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is proposing to determine that the phase 2 standards of performance in the CPS for new base load combustion turbines are not achievable. Accordingly, the Agency is proposing to repeal the phase 2 requirements for base load combustion turbines.

[199] If a storage site does not have enough natural gas available to fuel a new base load combustion turbine or enough transmission capacity to deliver the generated electricity to end users that infrastructure would have to be developed prior to the new combustion turbine commencing operation. Developing that infrastructure could result in additional costs to the owner/operator of the new base load combustion turbine.

[200] While transmission lines are conductive of electricity, they have some resistance that results in dissipation of the electrical energy in other forms (*e.g.,* heat). In effect, when transmitted over long distances, the electric energy delivered to an end user is less than the electric energy produced at the generating source (in this case, a stationary combustion turbine). In the CPS, consideration of this effect was generally accounted for.

The EPA solicits comment on the arguments for the proposed repeal of the phase 2 standards for base load combustion turbine EGUs. Specifically, the EPA solicits comment on its proposed conclusion that 90 percent CCS is not an adequately demonstrated system of emission reduction for base load stationary combustion turbine EGUs. The EPA further solicits comment on the status of any projects or developments regarding CCS on stationary combustion turbines, as well as on the operation of CO_2 capture equipment under the conditions (*e.g.,* variable load, startups) that would affect base load stationary combustion turbines. The EPA further solicits comment on its proposed conclusion that the cost of 90 percent CCS for new base load combustion turbines is not reasonable, including on any considerations related to taking the IRC section 45Q tax credit into account when calculating the costs of CCS in the context of a BSER analysis. The EPA further requests comment on the costs of CCS, including on the interplay of design capture efficiency, actual capture efficiency, and cost effectiveness. The EPA also solicits comment on its proposed determination that, because it is unlikely that the infrastructure for CCS can be deployed by the January 1, 2032, compliance date, the phase 2 standards of performance are not achievable for new base load combustion turbines.

VI. Request for Comments

We solicit comments on this proposed action. Specifically, we are soliciting comment on the following:

Primary Proposal

- The proposed interpretation of CAA section 111 to require, or at least authorize the EPA to require, an Administrator's determination of significant contribution for the air pollutant under consideration (C–1)
- Whether CAA section 111 requires a significant contribution finding for the fossil fuel-fired EGU source category first created in the 2015 NSPS (C–2)
- The proposed interpretation of what it means for a source category to contribute "significantly" to dangerous air pollution (C–3)
- Any other relevant arguments and information, including with respect to legitimate reliance interests on the 2015 NSPS and CPS (C–4)
- The interpretation that it is appropriate to regulate emissions of an air pollutant from a source category only if those emissions contribute significantly to dangerous air pollution (C–5)

• The textual requirements of CAA section 111(b), relevant context from the remainder of CAA section 111, and relevant structural arguments regarding the CAA more generally, including statutory provisions not specifically discussed in this proposal (C–6)

• The alternative interpretation of CAA section 111 to at least authorize the EPA to require a determination that an air pollutant significantly contributes to dangerous air pollution as a predicate to imposing standards of performance including with respect to whether the text of CAA section 111(b) confers sufficient discretion on the EPA and whether additional provisions of CAA section 111 or the CAA more generally inform the scope of that discretion (C–7)

• Whether the EPA erred in determining that it was not required to make a significant contribution finding in the 2015 NSPS or in not revisiting the issue in the CPS, and whether or not it would be appropriate to exercise its discretion here by requiring such a finding for GHG emissions from the fossil fuel-fired power plant source category (C–8)

• The change in interpretation from the 2015 NSPS, which allowed the EPA to regulate additional pollutants without ever having made a significant contribution finding for that pollutant, including any specific reliance interests relevant to the interpretation taken in the 2015 NSPS, as carried over into the CPS, and the relative strength of the rationale for these respective interpretations (C–9)

• Whether and how the Supreme Court's recent decision in *Loper Bright* should inform the EPA's approach to interpreting CAA section 111 and selecting which interpretation better reflects the best reading of the statute (C–10)

• Whether its proposed interpretation of CAA section 111(b)(1)(A) as requiring a pollutant-specific significant contribution finding is necessary to avoid implicating the major questions doctrine as articulated by the Supreme Court in *West Virginia.* Specifically, whether the proposed interpretations in this section are necessary to prevent the Agency from improperly expanding its regulatory authority by determining that emissions of de minimis amounts of air pollutants, or non-harmful substances that may nevertheless be defined as air pollutants, should be regulated under CAA section 111 (C–11)

• The strength of this interpretation and its application to GHG emissions by EGUs (C–12)

• The proposed determination that GHG emissions from the EGU source category do not ''contribute significantly'' to dangerous air pollution under CAA section 111(b)(1)(A) (C–13)

Alternative Proposal

• The BSER determinations or standards of performance and related requirements for new and reconstructed intermediate load and low load fossil fuel-fired stationary combustion turbines (C–13)

• The BSER determinations or standards of performance and related requirements for phase 1 for new and reconstructed base load fossil fuel-fired stationary combustion turbines (C–14)

Alternative Proposal—Carbon Capture and Storage

• The position that CPS included an incorrect accounting for the costs of control as the EPA should not be considering tax credits when determining the cost of the control (C–15)

• The arguments for repealing the 90 percent CCS-based requirements of the emission guidelines pertaining to long-term coal-fired steam generating units (C–16)

• The proposed conclusion that 90 percent CCS is not an adequately demonstrated system of emission reduction (C–17)

• The proposal that the performance of the CO_2 capture system at Boundary Dam Unit 3 is not a sufficient basis for determining that 90 percent CCS is adequately demonstrated for coal-fired steam generating units (C–18)

• The status and performance of CCS projects and technologies more generally, especially on projects that inform the question of whether 90 percent CCS is adequately demonstrated (C–19)

• The proposed conclusions regarding the impacts of startup and of variability more generally on CCS performance, as well as on methods to control process parameters (pressure, velocity, *etc.*) and capture efficiencies under startup and variable load, and what differences in those methods exist where the CO_2 capture system processes all or part of the flue gas (C–20)

• The proposed conclusion that the cost of 90 percent CCS for long-term coal-fired steam generating units is not reasonable, including on any considerations related to taking the IRC section 45Q tax credit into account when calculating the costs of CCS in the context of a BSER analysis (C–21)

• The costs of CCS for existing coal-fired steam generating units, including on the interplay of design capture efficiency, actual capture efficiency, and cost effectiveness (C–22)

• The proposed determination that, because it is unlikely that the infrastructure for CCS can be deployed by the January 1, 2032, compliance date, the degree of emission limitation is not achievable for long-term coal-fired steam generating units (C–23)

Alternative Proposal—Natural Gas Co-Firing

• The proposed repeal of the 40 percent co-firing BSER (C–24)

• Considerations related to the supply of and demand for natural gas, and on how the diversion of natural gas to coal-fired steam generating units would impact the energy system (C–25)

• The relative efficiency of co-firing natural gas versus using it in a combustion turbine to generate electricity (C–26)

• The proposed conclusion that 40 percent natural gas co-firing cannot be the BSER for a coal-fired steam generating units because it constitutes generation shifting (C–28)

• The determination that a degree of emission limitation based on 40 percent natural gas co-firing is not achievable because it is unlikely that the pipeline infrastructure necessary can be deployed by the compliance date of January 1, 2030 (C–29)

• Considerations related to the achievability of the presumptive standard of performance for medium-term coal-fired steam generating EGUs in the CPS (C–30)

Alternative Proposal—Natural Gas- and Oil-Fired Steam EGUs

• The arguments for repealing the requirements of the emission guidelines pertaining to natural gas- and oil-fired steam generating units (C–31)

Alternative Proposal—Coal-Fired Steam Generating Units Undertaking a Large Modification

• The rationale for repealing the CCS-based standards of performance for coal-fired steam generating units undertaking a large modification (C–32)

Alternative Proposal—Phase 2 Standards

• The arguments for the proposed repeal of the phase 2 standards for base load combustion turbine EGUs (C–33)

• The proposed conclusion that 90 percent CCS is not an adequately demonstrated system of emission reduction for base load stationary combustion turbine EGUs (C–34)

• The status of any projects or developments regarding CCS on stationary combustion turbines (C–35)

• The operation of CO_2 capture equipment under the conditions (*e.g.,* variable load, startups) that would affect base load stationary combustion turbines (C–36)

- The proposed conclusion that the cost of 90 percent CCS for new base load combustion turbines is not reasonable, including on any considerations related to taking the IRC section 45Q tax credit into account when calculating the costs of CCS in the context of a BSER analysis (C–37)
- The costs of CCS, including on the interplay of design capture efficiency, actual capture efficiency, and cost effectiveness (C–38)
- The proposed determination that, because it is unlikely that the infrastructure for CCS can be deployed by the January 1, 2032, compliance date, the phase 2 standards of performance are not achievable for new base load combustion turbines (C–39)

VII. Statutory and Executive Order Reviews

Additional information about these statutes 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 action is a significant regulatory action under E.O. 12866 section 3(f)(1) that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in the course of E.O. 12866 review have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Proposed Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units,* is available in the docket.

The estimated economic impacts detailed in this section represent the projected cost savings of the primary proposal as well as represent the projected impacts of the alternative proposal. For additional information, see section 2.3.2 of the RIA for this action.

We present the estimated present value (PV) and equivalent annualized value (EAV) of the projected cost savings of repealing the GHG standards for EGUs calculated for the years 2026 to 2047 in 2024 dollars discounted to 2025. In addition, the Agency presents the results for specific snapshot years, consistent with historical practice. These snapshot years are 2028, 2030, 2035, 2040 and 2045. The full benefit-cost analysis, which is contained in the RIA for this rulemaking, is available in the docket.

The power industry's compliance costs are represented in this analysis as the change in electric power generation costs due to the proposed repeal of the GHG standards for EGUs. In simple terms, these costs are an estimate of the decreased power industry expenditures resulting from the repeal of the GHG requirements for EGUs.[201]

In table 4–4 of the RIA, we present the monetized impact estimates associated with the emissions of $PM_{2.5}$ and O_3 for the proposed action.

Table 1 presents the estimates of compliance cost savings of this proposed action. This table presents the PV and EAV of these estimated impacts for the timeframe of 2026 to 2047 discounted at 3 percent and 7 percent in 2024 dollars discounted to 2025.

TABLE 1—PRESENT VALUE (PV) AND EQUIVALENT ANNUALIZED VALUE (EAV) OF THE COMPLIANCE COST SAVINGS

[Billion 2024$, discounted to 2025]

3% Discount rate		7% Discount rate	
PV	EAV	PV	EAV
19	1.2	9.6	0.87

Note: The estimated cost savings detailed in this table represent the projected cost savings of the proposal and represent the projected cost savings of the alternative proposal, as described in the RIA. These values do not include all impacts of the proposal, such as effects on emissions, which are further described in section 4 of the RIA.

B. Executive Order 14192: Unleashing Prosperity Through Deregulation

This action is expected to be an Executive Order 14192 deregulatory action. Details on the estimated cost savings of this proposed action can be found in the EPA's analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Proposed Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units,* is available in the docket.

[201] We note that the RIA for this action follows the EPA's historical practice of using a technology-rich partial equilibrium model of the electricity and related fuel sectors to estimate the incremental costs of producing electricity under the requirements of proposed and final major EPA power sector rules. The EPA has also included in the RIA for this action additional analyses that consider additional facets of the economic responses to the proposed action. These analyses include estimates of the full resource requirements, some of which were paid for through subsidies in the partial equilibrium analysis, and economy-wide social costs associated with complying with the CPS, which will no longer be incurred under this proposed action. Note that the analysis presented here is based on the model runs conducted as part of the 2024 CPS RIA, and that the model has not been updated and re-run to account for changes in the energy system that have occurred over the past year.

C. Paperwork Reduction Act (PRA)

The information collection activities in this proposed action have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. In the primary proposal, the EPA proposes to amend the information collection requests for 40 CFR part 60, subparts TTTT, TTTTa, and UUUUb. In the alternative proposal, the EPA proposes to amend the information collection request for 40 CFR part 60, subpart UUUUb. Details on the amendments for these subparts are described below.

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

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 the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' or by using the search function. OMB must receive comments no later than [insert date 30 days after publication in the **Federal Register**].

1. 40 CFR Part 60, Subpart TTTT

The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2465.06. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Respondents/affected entities: Owners and operators of fossil fuel-fired EGUs.

Respondent's obligation to respond: No longer mandatory.

Estimated number of respondents: 92.

Frequency of response: No response required.

Total estimated burden: 3,130 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $376,000 (per year), includes $0 annualized capital or operation & maintenance costs.

2. 40 CFR Part 60, Subpart TTTTa

The ICR document that the EPA revised is EPA ICR number 2771.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Respondents/affected entities: Owners and operators of fossil fuel-fired EGUs.

Respondent's obligation to respond: No longer mandatory.

Estimated number of respondents: 2.

Frequency of response: No response required.

Total estimated burden reduction: 110 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost savings: $12,000 (per year), includes $0 annualized capital or operation & maintenance costs.

3. 40 CFR Part 60, Subpart UUUUb

The ICR document that the EPA revised is EPA ICR number 2770.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

This action proposes to repeal requirements on state governments with existing fossil fuel-fired steam generating units. The information collection requirements are based on the recordkeeping and reporting burden reduction associated with developing, implementing, and enforcing a state plan to limit GHG emissions from these existing EGUs.

Respondents/affected entities: States with one or more designated facilities covered under subpart UUUUb.

Respondent's obligation to respond: No longer mandatory.

Estimated number of respondents: 43.

Frequency of response: No response required.

Total estimated burden reduction: 89,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost savings: $11.7 million, includes $35,000 annualized capital or operation & maintenance costs.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the EPA concludes that the impact of concern for this rule is any significant adverse economic impact on small entities and that the Agency is certifying that this proposed rule will not have a significant economic impact on a substantial number of small entities because this action relieves regulatory burden on the small entities subject to the rule. 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 requirements that could potentially impact small entities. Thus, the proposed repeal of the requirements in the emission guidelines will not impose any requirements on small entities. The proposed repeal of requirements for new, modified, and reconstructed fossil fuel-fired EGUs will relieve regulatory burden on the small entities subject to the rule. In the 2024 CPS RIA, the EPA identified 14 potentially affected small entities that own NGCC units considered in the analysis. Of these, three were projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035 and none were projected to experience compliance costs greater than or equal to 3 percent of generation revenues in 2035. Under the proposed repeal, these projected compliance cost changes for small entities will be avoided. Consequently, the EPA expects that this deregulatory action, if finalized as proposed, would relieve the regulatory burden for facilities that, absent this proposed repeal, would be affected by the provisions from the CPS. As a result, this action will not have a significant economic impact on a substantial number of small entities under the RFA. We have therefore concluded that this action will relieve regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million (adjusted annually for inflation) or more (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any State, local, or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

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 will not have substantial direct effects on Tribal governments, 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 this action. However, because of Tribal interest on this proposed rule and consistent with the EPA Policy on Consultation with Indian Tribes, the EPA will be offering government-to-government consultation with Tribes.

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

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is subject to Executive Order 13045 because it is a significant regulatory action under section 3(f)(1) of Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. The 2015 NSPS and the CPS were anticipated to reduce emissions of CO_2, NO_X, SO_2, PM, mercury, and HAP, and some of the benefits of reducing these pollutants would have accrued to children. This proposed action is expected to decrease the impact of the emissions reductions estimated from the 2015 NSPS and the CPS on these benefits, as discussed in the RIA.

This proposed action does not affect the level of public health and environmental projection already being provided by existing NAAQS 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 action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy over the analysis period (2024–2047) based on the results presented in the 2024 CPS RIA.

J. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This rulemaking does not involve technical standards.

Lee Zeldin,

Administrator.

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