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RE: COMMENTS OF AMERICAN MUNICIPAL POWER, INC. ON THE PROPOSED RULE TO REPEAL THE 2024 CARBON RULE; Docket ID No. EPA-HQ-OAR-2025-0124

American Municipal Power, Inc. (AMP) appreciates the opportunity to submit to the U.S. Environmental Protection Agency (EPA or Agency) the following comments on the Proposed Rule to repeal the Carbon Rule adopted in May 2024 (Proposed Rule).[1] The main purpose of the Proposed Rule is to repeal the performance standards that EPA established for regulating carbon dioxide (CO_2) emissions from affected fossil fuel-fired electric generating units (EGUs) under section 111 of the Clean Air Act (CAA or Act). In addition, the Proposed Rule seeks comments on the achievability of the current CO_2 performance standards that the Carbon Rule[2] established for certain new stationary source combustion turbines,[3] which would continue to apply if the Agency does not revoke its authority to regulate CO_2 emissions from affected EGUs under CAA section 111. AMP is submitting detailed comments on both matters for EPA's consideration.

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[1] *Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units*, 90 Fed. Reg. 25,752 (June 17, 2025) (Proposed Rule).

[2] *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*, 89 Fed. Reg. 39,798 (May 9, 2024) (Carbon Rule).

[3] References to "new" stationary source combustion turbines in these comments also include existing turbine units undergoing reconstruction as set forth in 40 C.F.R. § 60.15.

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OVERVIEW OF AMP'S PERSPECTIVE AND APPROACH

AMP is the nonprofit wholesale power supplier and services provider for more than 130 Members in the States of Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Virginia, and West Virginia, as well as the Delaware Municipal Electric Corporation. AMP's members collectively serve approximately 661,000 residential, commercial, and industrial customers and have a system peak of more than 3,400 megawatts (MW). AMP's core mission is to be public power's leader in wholesale energy supply and value-added member services. AMP offers its Member municipal electric systems the benefits of scale, expertise, and leadership in providing and managing energy services. AMP serves as a joint action organization, representing Members with a broad spectrum of views and we recognize that some of them may be filing separate comments.

Representation of customers, owners, and operators of electric generating assets in ten states informs AMP's comments, which outline general policy principles and key technical considerations on the proposed regulatory repeal options. These comments are intended to provide points of reference to guide EPA's proposed repeal of the Carbon Pollution Standards (CPS) and necessary changes to the Phase 1 CO_2 performance standards for new and modified combustion turbines.

These comments reflect AMP's core values for promoting reliability, flexibility, affordability, and feasibility. The Proposed Rule will achieve consistency with these core values by —

- *Ensuring electric grid reliability* by avoiding the premature mandatory shutdown of existing dispatchable gas generation until replacement generating capacity can be built and brought online with at least the same accredited capacity and other reliability attributes as the retiring capacity;

- *Establishing a workable regulatory framework that maximizes compliance flexibility* for implementation of emissions standards over reasonable time horizons through flexible mechanisms to the maximum extent permissible; and provide states with sufficient time and broad discretion in the development of state plans for implementing emissions control requirements in a flexible, cost-effective manner that is tailored to state and local priorities to the extent permissible;

- *Keeping a reliable supply of electricity affordable to retail customers and businesses* that AMP and its members serve by adopting reasonably achievable emissions control requirements that do not impose exorbitant control costs

incommensurate with environmental gains and avoid stranded costs resulting from the forced premature retirement of existing electric generating facilities; and

- *Developing reasonably achievable performance standards for reducing CO_2 and other air emissions* that are based on technically and economically feasible emissions control technologies suitable for the changing energy landscape and operational requirements of the grid. This includes subcategories and standards for turbines operating in simple- and combined-cycle duty, and varying outputs and design bases.

I. EPA SHOULD PROCEED WITH THE REPEAL UNDER BOTH PROPOSED ALTERNATIVES.

EPA has proposed two options for the repeal of the CO_2 performance standards adopted for affected EGUs under section 111 of the CAA. Each of these options provides a separate and independent legal basis for invalidating those performance standards.

The "Primary Proposal" would repeal all CO_2 performance standards for both new and existing affected fossil fuel-fired EGUs based on the revocation of the "endangerment finding" that EPA previously made for the EGU source category under CAA section 111.[4] Specifically, it repeals the performance standards adopted for existing coal-fired EGUs and new stationary source combustion turbines[5] under the 2024 Carbon Rule and the performance standards EPA set in 2015 for new coal-fired EGUs based on partial Carbon Capture and Storage (CCS).

The "Alternative Proposal" seeks to repeal the CO_2 control requirements adopted under the 2024 Carbon Rule. This approach would repeal most, but not all, of the CO_2 performance standards applicable to affected fossil fuel-fired EGUs. The CO_2 performance standards invalidated would include those standards requiring existing coal-fired EGUs to install CCS achieving 90% capture by 2032 or co-fire with 40% natural gas by 2030, as well as the standards requiring new baseload stationary source combustion turbines to install CCS by 2032. The repeal of these standards would be based on an EPA determination that those standards were set based on control technologies that are not adequately demonstrated, not economically or technically

[4] EPA established two legal bases for regulating CO_2 emissions from new and existing fossil fuel-fired EGUs under CAA section 111. One basis was a determination that EPA had a "rational basis" for its CO_2 regulatory authority because the EGU source category was already regulated for conventional air pollutants under CAA section 111. The other basis was an alternative determination that CO_2 emissions from the EGU source category cause or significantly contribute to air pollution that may reasonably be anticipated to endanger public health or the environment. The focus of these comments is on EPA's alternative basis for establishing its CO_2 regulatory authority based on an endangerment finding.

[5] Reference to "new" stationary source combustion turbines in these comments also includes existing turbine units undergoing reconstruction as set forth in 40 C.F.R. § 60.15.

feasible, and would result in generation shifting in violation of *West Virginia v. EPA*.[6] The Alternative Proposal would not repeal or otherwise affect the CO_2 performance standards that apply to new intermediate-load and baseload combustion turbines upon immediate startup of the affected new turbine facility. Nor would the Alternative Proposal limit EPA's authority to adopt a replacement rule in the future that would establish entirely new performance standards for new and existing EGUs.

However, the two alternatives advanced by EPA in the Proposed Rule are not mutually exclusive. Rather, they provide two wholly separate and independent predicates for EPA to repeal the CO_2 performance standards adopted in the 2024 Carbon Rule. One determination would repeal the standards based on the repeal of the significant contribution finding, while the other determination would be based on a different legal and factual basis — the performance standards were not based on "adequately demonstrated" technologies and seek to establish limits that were neither achievable nor economically feasible. This combined approach will likely result in a stronger and more durable repeal of the performance standards for fossil fuel-fired EGUs. If, for example, a court were to invalidate a broad repeal under the Primary Proposal through a revocation of the endangerment finding, EPA's determination that the standards are invalid due to fundamental flaws in setting performance standards under the Alternative Proposal could provide an independent and separate legal basis for repealing the standards.

II. STRONG LEGAL AND FACTUAL BASES EXIST FOR EPA TO REVOKE THE ENDANGERMENT FINDING UNDER THE PRIMARY PROPOSAL.

AMP supports the Primary Proposal to repeal the current CO_2 performance standards established for all affected fossil fuel-fired EGUs under CAA section 111. Strong legal, factual, and policy bases support EPA's proposal to revoke the endangerment finding that CO_2 emissions from the EGU source category are not significantly contributing to air pollution that endangers public health or welfare. A review of these legal, factual, and policy bases is presented below.

A. EPA Has a Strong Legal Basis for Its Proposed New Statutory Interpretation of the Significant Contribution Requirement.

The CAA authorizes the regulation of fossil fuel-fired EGUs under CAA section 111 only if EPA finds that the EGU source category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[7] Referred to as the endangerment finding, this multi-step process requires EPA to make

[6] 597 U.S. 697 (2022).
[7] Section 111(b)(1)(A) of the CAA.

two related determinations. The first step of the process is for EPA to make a "significant contribution" determination regarding whether emissions from the EGU source category are causing, or contributing significantly to, air pollution. The second step of the process is for EPA to determine whether air pollution from the EGU source category may be endangering public health or welfare.

In the Proposed Rule, EPA does not take issue with the second prong of the endangerment finding regarding whether Greenhouse Gas (GHG) emissions are having climate change effects that are posing an endangerment to public health or welfare. Instead, the Proposed Rule focuses on the first prong regarding causation or significant contribution, advancing a new interpretation of the significant contribution requirement in CAA section 111(b)(1)(A) based on the best reading of the statutory text.

Section 111(b)(1)(A) authorizes EPA to regulate CO_2 emissions from the EGU source category only if those emissions are determined to "cause or contribute significantly" to dangerous air pollution endangering public health or welfare. Focusing only on this first step of the process for making an endangerment finding (i.e., the significant contribution determination),[8] the relevant inquiry pertains to the meaning of two statutory terms, "cause" and "contributing significantly." Consistent with their ordinary meanings, these terms clearly convey that there must be a meaningful connection or consequential linkage between CO_2 emissions from affected EGUs and dangerous air pollution before EPA can make an affirmative significant contribution determination.

The term "cause" requires a direct, substantial link between an action and an effect, whereby an action is determined to bring about an effect. In regulatory contexts such as here, the test for determining causation is logically based on the legal principles of proximate cause, meaning the effect would not have occurred but for the action and that action was sufficiently related or connected to the effect.[9] Notable examples illustrating this causal relationship include heavy rainfall causing the flooding of a river or smoke from wildfires resulting in a violation of ambient air quality standards.

While not requiring strict or direct causation, the phrase "contribute significantly" also connotes a tangible or meaningful linkage between the action and the effect. The

[8] The other issue pertains to whether CO_2 and other GHG emissions are having climate change effects that are endangering public health or the environment. The Proposed Rule does not address this endangerment issue because it is irrelevant to its analysis in support of the proposal to revoke the endangerment finding.
[9] The Supreme Court has characterized the proximate-cause analysis as examining whether the effect "has a sufficiently close connection" to the action. *Bank of Am. Corp. v. City of Miami*, *Fla.*, 581 U.S. 189, 201 (2017) (citation omitted). In the context of making a significant contribution determination under CAA section 111(b)(1)(A), the proximate-cause analysis must determine whether the air pollutant (CO_2 emissions from the EGU source category) have a sufficiently close connection to the endangerment caused by the air pollutant (global climate change).

term “contributes” means (in ordinary usage) to give something that will help to cause or bring about a result or outcome or effect, often in combination with other factors or actions.[10] By requiring the contribution to be “significant,” the statute strengthens the materiality of the linkage by requiring that the action results in effects that are something more than trivial or negligible. This is clearly indicated by the fact that the term “significant” means “having or likely to have influence or effect” that is “important” or “valuable.”[11] These two terms (“important” and “valuable”) further underscore that a significant contribution is one of great value (i.e., crucial, essential, or necessary) that has a sizeable effect or influence (i.e., something that can change outcomes or make a difference).

For these reasons, the plain meaning of the statutory phrase “cause or contribute significantly” clearly indicates that a significant contribution determination under CAA section 111(b)(1)(A) requires something more than a mere claim or showing that CO_2 emissions from the EGU source category might be having some undefined minor or negligible impacts on global climate change. Rather, it requires an EPA demonstration that those EGU emission reductions will likely have tangible and material impacts on global atmospheric CO_2 levels such that future regulations to reduce those emissions would result in non-trivial changes to the concentration of that pollutant in the atmosphere. EPA’s failure to meet both requirements provides strong grounds for EPA to revoke the endangerment finding for CO_2 emissions from the EGU source category under the Primary Proposal.

EPA Decisions Not to Establish a National Ambient Air Quality Standard (NAAQS) for Greenhouse Gases. EPA’s proposed statutory interpretation effectively limits the geographic scope of the significant contribution (and thus regulation under CAA section 111) to those air pollutants having local or regional impacts within the United States. By the same token, CO_2 and other GHGs would be excluded from section 111 regulation to the extent that they are global air pollutants having only undefined and unquantifiable global impacts. This proposed statutory interpretation is consistent with EPA’s longstanding practice of not regulating GHGs as a NAAQS criteria pollutant through the State Implementation Plan (SIP) process under CAA section 110.

The first step of the SIP regulatory process would entail EPA establishing a NAAQS for GHGs. The establishment of a GHG NAAQS would require EPA to make an endangerment finding like the one required for regulation under CAA section 111 — namely, the Agency would make a finding that GHGs “cause or contribute to air pollution

[10] *See Meriam-Webster Dictionary* definition of “contribute” available here.
[11] *See id.* definitions of “significant” available here, “important” available here, and “valuable” here.

which may reasonably be anticipated to endanger public health or welfare."[12] The Agency has not only declined to make such a finding but has explained on the record on several occasions the many compelling reasons why it is neither appropriate nor feasible to do so.[13] The following are just a few of the major implementation problems that illustrate why EPA has interpreted the statute as not authorizing EPA to issue an endangerment finding for the establishment of a GHG NAAQS under CAA section 108(a):

Incompatibility with NAAQS Implementation Framework. The CAA established a SIP regulatory framework that was designed to regulate those air pollutants with local or regional impacts, not for globally dispersed pollutants like GHGs. The applicable statutory deadlines and SIP requirements are premised on the ability of states to adopt and implement SIP control measures within their borders and achieve measurable local air quality improvements within a set timeframe (five to ten years). Since GHGs are globally mixed and have long atmospheric lifetimes, it is impossible for states to establish and implement SIP control programs that would ever attain a NAAQS that EPA might set for GHGs. Rather, the attainment of the NAAQS would require global GHG emissions reductions over long time frames, which no individual state could ever implement, and thereby result in widespread and perpetual nonattainment of the GHG NAAQS.

Practical Unworkability. As noted above, achieving a GHG NAAQS would require global reductions on GHG emissions, not just national or state-level action to reduce GHG emissions. States nonetheless would still be legally required to develop SIPs to attain an ambient air quality standard that is impossible to meet through state or local actions alone, setting up inevitable and widespread nonattainment for all states, most likely on a permanent basis. Furthermore, the CAA typically requires attainment of NAAQS within ten years. Given the magnitude, scale, and persistence of GHG atmospheric loadings, it is not feasible for any state (let alone the entire United States) to implement emissions control requirements that can achieve meaningful reductions in GHG ambient air concentrations within this period, rendering the statutory deadlines entirely unworkable and thereby meaningless.

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[12] *See* Section 108(a) of the CAA (directing EPA to establish air quality criteria for those air pollutants identified as causing or contributing to air pollutions determined to be endangering public health or welfare); section 109 of the CAA (directing EPA to establish NAAQS for each air pollutant for which an air quality criterion has been established under CAA section 108).

[13] *See Andrew R. Wheeler, EPA Administrator, Denial of Petitions to Establish National Ambient Air Quality Standards for Greenhouse Gases, to Regulate Greenhouse Gases Under Clean Air Act Section 115, and to Regulate Greenhouse Gases as Hazardous Air Pollutants* (Jan. 19, 2021) (Denial of Petition for establishing a GHG NAAQS); *Advanced Notice of Proposed Rule Rulemaking; Regulating Greenhouse Gas Emissions Under the Clean Air Act*, 73 Fed. Reg. 4434 (July 30, 2008) (describing many reasons why establishing a NAAQS for GHGs would be ill-suited for regulation through the SIP process).

EPA faces practical challenges in regulating CO_2 emissions from the EGU source category under CAA section 111. As the Proposed Rule recognizes, the only CO_2 control measures available to reducing CO_2 emissions from the fossil fuel-fired EGU are "not permissible as [a best system of emissions reduction (BSER)], not adequately demonstrated, cost unreasonable, or potentially ineffective in reducing emissions" through heat rate improvements.[14] These practical difficulties, which are major regulatory impediments for controlling CO_2 emissions, further bolster EPA's proposed interpretation as the best reading of the statute — that Congress only intended to allow EPA to make affirmative significant contribution determinations for those air pollutants suitable for regulation under CAA section 111. Put another way, those air pollutants suitable for regulation under CAA section 111 are limited to having local or regional air quality impacts, which excludes globally mixed GHGs with long atmospheric lifetimes for which the emissions reductions will achieve negligible or trivial climate change benefits.

It is important to bear in mind that the current CAA contains a model of how dangerous air pollution with global impacts should be addressed. After the United States and other countries ratified the Montreal Protocol on Substances that Deplete the Ozone Layer on September 16, 1987,[15] Congress included implementing provisions of that treaty in the 1990 CAA Amendments as Title VI Ozone Depleting Substances. EPA then developed regulatory programs based on those new statutory provisions.

Congress and EPA have demonstrated that efforts to combat globally dispersed, dangerous air pollution can be effective, but statutory provisions clearly intended to address air pollution with local or regional impacts are not suitable for that task. International treaties are binding but also distribute burdens and costs amongst the parties to achieve a common objective. EPA taking unilateral action to regulate power sector CO_2 emissions has the opposite effect of a treaty — costs and burdens accrue to generation owners and the general public but without any ability to meet the stated objective of reducing global GHG emissions. The CAA may be the vehicle to regulate GHG emissions in the future, but this effort will require amendment by Congress to do so.

The Major Questions Doctrine Supports EPA's Proposed New Interpretation. The overall objective of the Primary Proposal is to adopt a new interpretation of the "significant contribution" requirement that limits the scope of EPA's regulatory authority under CAA section 111. In effect, this new interpretation would limit section 111 regulation to air pollutants with local or regional impacts and preclude regulation of CO_2 and other global

[14] Proposed Rule, 90 Fed. Reg. at 25,766.
[15] United Nations Environmental Program, *About Montreal Protocol*, https://www.unep.org/ozonaction/who-we-are/about-montreal-protocol (visited July 30, 2025).

air pollutants. This limitation on EPA's authority makes common sense and is necessary to avoid conflicts with the major questions doctrine.

Narrowing the scope of section 111 regulation to only conventional air pollutants is not only in keeping with the structure, function, and objectives of the CAA, but is also is necessary to prevent EPA from running afoul of the major questions doctrine, as articulated by the Supreme Court in *West Virginia*,[16] which bars federal agencies from taking actions that have extraordinary economic and political significance without explicit and clear authorization from Congress.[17] As a result, EPA may not claim authority to regulate CO_2 and other global air pollutants, given that EPA's underlying claim of authority concerns an issue of "vast 'economic and political significance.'" [18] When Congress wants EPA to address air pollution with global impacts, it knows how to clearly express its intent. It has not done so with respect to CO_2 and other GHGs.

B. CO_2 Emissions from the EGU Source Category Do Not Qualify As Significant Contribution.

In the 2015 Power Plant Rulemakings, EPA determined that CO_2 emissions from the EGU source category significantly contribute to air pollution posing risks to public health and the environment based on several key considerations. One consideration was the large volume of CO_2 emissions emitted by affected EGUs in the United States. The other consideration was tied to the 2009 endangerment finding that EPA made for mobile sources. The 2009 endangerment finding determined that mobile sources contributed to climate change based on a substantial body of evidence documenting extensive climate change effects experienced in recent years, such as rising temperatures worldwide and extreme weather events.[19]

The discussion below provides a review of the major flaws in EPA's prior significant contribution determination upon which EPA has relied in concluding that it has authority to set CO_2 performance standards for the EGU source category under CAA section 111. Those flaws include an attenuated chain of causations used to link EGU emissions to current trends in climate change effects, over-inflated significance given to the volume of CO_2 emissions from the EGU source category, and the lack of climate change benefits resulting from the CO_2 regulation of affected EGUs under CAA section 111.

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[16] 597 U.S. at 720-24.
[17] *See id.* at 700-02; *Util. Air Regulatory Grp. v. EPA,* 573 U.S. 302, 324 (2014).
[18] 573 U.S. at 324 (citation omitted).
[19] *See Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act,* 74 Fed. Reg. 66,496 (Dec. 6, 2009).

Attenuated Causal Linkage. In 2015, EPA made a pollutant-specific significant contribution determination for CO_2 emissions from the EGU source category when it promulgated new source performance standards for the regulation of new affected EGUs and applied the Clean Power Plan to regulated existing affected EGUs.[20] In doing so, EPA relied on a long and attenuated chain of causation to support its claim that CO_2 emissions in the United States are significantly contributing to air pollution endangering public health and welfare. As EPA outlined in the Proposed Rule, this causal change 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.[21]

EPA's reliance on such a long and attenuated causal chain is contrary to the statutory requirements for making a significant contribution determination under CAA section 111(a)(1)(A). As discussed previously, the plain meaning of the phrase "cause or contribute significantly" clearly indicates that a significant contribution determination under this section requires something more than a mere claim or showing that CO_2 emissions from the EGU source category might be having some undefined minor or negligible impacts on global climate change. As a result, it is insufficient for the Agency to base its significant contribution determination on such an attenuated causation chain that merely shows some possible linkage between EGU emissions and increased risks to public health and welfare.

An Over-Inflated Significance Given to Volume of EGU Emissions. Another flaw in EPA's significant contribution analysis is the over-inflated significance that the Agency

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[20] *See Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 89 Fed. Reg. 64,510, 64,529-32 (Oct. 23, 2015) (setting CO_2 performance standards for new affected fossil fuel fired EGUs); *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 80 Fed. Reg, 64,662, 64,710-64,717 (Oct. 23, 2015) (setting CO_2 performance standards for existing affected fossil fuel fired EGUs) (collectively, 2015 Power Plant Rulemakings).

[21] Proposed Rule, 90 Fed. Reg. at 25,767.

gave to the volume of CO_2 emissions from the EGU source category. EPA failed to account for the fact that EGU emissions are a very small fraction of the total GHG emissions worldwide and that small fraction has significantly declined over the last 25 years, with this trend expected to continue in the foreseeable future. For example, the U.S. power sector emissions comprised about 5.5% of total global emissions in 2005 and those global CO_2 emissions levels have steadily declined since then to only about 3% of total global emissions by 2022.[22]

Furthermore, the decline in EGU emissions in the United States has been more than offset by increased EGU emissions in other countries that are rapidly electrifying and thereby increasing their electric power generation capacities, including through the deployment of coal-fired EGUs (which is likely to continue for the foreseeable future). For example, China and India are substantially increasing their CO_2 emissions by adding more than 530,000 MW of new coal-fired generation to their existing coal fleets and, as a result, global use of coal continues to grow — with 2024 seeing the most coal use ever.[23]

This quantitative comparison demonstrates that reducing CO_2 emissions from fossil fuel-fired EGUs in the United States will neither achieve net reductions in global CO_2 emissions nor have any meaningful impact on global GHG atmospheric concentrations when other countries continue to increase their use of fossil fuels and CO_2 emissions. The lack of impact that U.S. coal plants have on global CO_2 emissions further supports EPA's determination that CO_2 emissions from affected EGUs do not significantly contribute to globally elevated concentrations of atmospheric GHG.

Negligible Climate Change Benefits. Another relevant indicator that EGU emissions are not having significant impacts on global climate change is the lack of climate change benefits that could ever result from even the most aggressive regulatory scheme for reducing CO_2 emissions from affected EGUs under CAA section 111. As discussed above, the plain meaning of the statutory phrase "significant contribution" not only requires EPA to demonstrate EGU emissions are having a quantifiable and meaningful adverse impact on global climate change. It also requires an EPA demonstration that those EGU reductions from future CO_2 regulations under CAA section 111 will likely have tangible and non-trivial benefits to global climate change.

Unlike conventional air pollutants that can have a localized or regional impact and direct consequences to public health and the environment, CO_2 and other GHGs are

[22] 90 Fed. Reg. at 25,767-78.
[23] *Id.* at 25,768.

global air pollutants for which EPA has failed to provide any quantifiable or defined assessment of the climate change benefits when making its significant contribution determination for the EGU source category. EPA's prior failure to make any analytic demonstration on the resulting climate change benefits provides further grounds for EPA to now conclude that CO_2 emissions from fossil fuel-fired EGUs do not significantly contribute air pollution posing risks to public health and the environment.

III. THE ALTERNATIVE PROPOSAL ESTABLISHES TECHNICAL AND LEGAL BASES TO REPEAL THE CO_2 PERFORMANCE STANDARDS FOR EXISTING COAL-FIRED EGUS.

EPA must follow a specific framework when setting federal standards of performance for existing coal-fired EGUs under section 111(d) of the CAA. That statutory-prescribed framework requires EPA to set federal performance standards at "achievable" levels by the application of the BSER that the Agency determines is "adequately demonstrated," while considering various factors, such as cost, non-air quality health and environmental impacts, and energy requirements.[24]

The discussion below begins by providing an overview of the regulatory framework for setting CO_2 performance standards for affected fossil fuel-fired EGUs under section 111 of the CAA. A detailed analysis of the many shortcomings that the 2024 Carbon Rule presents in attempting to adhere to this statutory framework follows. These shortcomings provide a strong legal and technical basis for EPA to repeal the CO_2 performance standards that EPA set for existing long-term, coal-fired EGUs based on CCS technologies, and existing medium-term, coal-fired EGUs based on 40% natural gas co-firing. Neither of these control technologies meet the statutory criteria contained in section 111 of the CAA and this failure provides a legal basis for EPA to repeal those performance standards under the Agency's Alternative Proposal.

[24] CAA § 111(a)(2).

A. The Statute Establishes a Detailed Regulatory Framework That EPA Must Follow in Setting CO_2 Performance Standards Under CAA Section 111.

The statute establishes a specific framework that EPA must follow when setting performance standards for affected new and existing fossil fuel-fired EGUs under section 111 of the CAA. That statutorily prescribed framework requires EPA to set federal performance standards at "achievable" levels that reflect the "best system of emission reduction . . . adequately demonstrated," while considering factors such as cost, non-air quality health and environmental impacts, and energy requirements.[25] As described below, courts have provided considerable guidance on how EPA may interpret and apply these statutory criteria when setting federal performance standards for new affected stationary sources under section 111(b) of the Act.

1. Control Technology Must Be Adequately Demonstrated.

The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has held that a system of emission reduction that has been "adequately demonstrated" is "one which has been *shown* to be reasonably *reliable*, reasonably *efficient*, and which can reasonably be expected to serve the interests of pollution control *without becoming exorbitantly costly* in an economic or environmental way."[26] In identifying control technologies that are adequately demonstrated, the Agency may "look toward what may fairly be projected for the regulated future" and project when a system will become available.[27] However, EPA is not permitted to engage in a "crystal ball inquiry."[28]

Both the text and structure of CAA section 111 also place clear limitations on EPA's discretion to make such forward-looking predictions on whether an emerging new technology has been adequately demonstrated. The statute requires the Agency to "review and, if appropriate, revise" new source performance standards for a listed category at least every eight years. This provision effectively confirms that those technologies or control systems requiring further development and enhancements should not serve the basis for setting the performance standards under CAA section 111(b). Instead, EPA should review the effectiveness of the technology or control system at the next eight-year review cycle and consider at that time whether it is adequately demonstrated.

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[25] *Id*.
[26] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (emphasis added); *see also NRDC v. Thomas*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986).
[27] *Portland Cement Ass'n v. Ruckelshaus*, 486 F. 2d 375, 392 (D.C. Cir. 1973).
[28] *Id.* at 391-92 (citing *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)).

Finally, the D.C. Circuit has ruled that "where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture."[29] Thus, an adequately demonstrated system must have an operational history with actual performance data that shows more than mere technical feasibility. Rather, the Agency must show that the technology is dependable, effective, and affordable for individual sources, based on actual operating experience within the source category or at sufficiently similar sources.

2. Emissions Limitations Must Be Achievable by All Affected Sources Under the Full Range of Operating Conditions Nationwide.

The D.C. Circuit has provided specific guidance on how EPA should determine what control levels are "achievable" by individual sources applying that system. EPA is required to explain how the standard "is achievable under the range of relevant conditions which may affect the emissions to be regulated,"[30] including "under most adverse conditions which can reasonably be expected to recur."[31] In addition, a performance standard that applies to all new sources in a category must be achievable "for the industry as a whole" and not just for a subset of sources.[32] As with determining whether a control technology is adequately demonstrated, EPA may not base its determination that a standard is achievable on "mere speculation or conjecture."[33]

EPA has failed to follow this statutory framework in setting CO_2 performance standards for both existing long-term, coal-fired EGUs based on CCS technologies and existing medium-term, coal-fired EGUs based on 40% natural gas co-firing. Neither of these control technologies meet the statutory criteria and that failure provides a legal basis for EPA to repeal those performance standards under the Agency's Alternative Proposal.

B. EPA Should Repeal Performance Standards Based on 90% Capture for Existing Long-Term Coal-Fired EGUs Under the Alternative Proposal.

The Alternative Proposal documents at least four major deficiencies in the technical basis upon which EPA relied in setting the CO_2 performance standards for long-term coal-fired EGUs. Each of these deficiencies provides independent legal

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[29] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999 (citing *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 787 (D.C. Cir. 1976)).
[30] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980).
[31] *Id.* at 431 n.46.
[32] *Id.* at 431.
[33] *Lignite Energy Council*, 198 F.3d at 934.

grounds for EPA to repeal the performance standards requiring long-term coal-fired EGUs to achieve 90% CO_2 capture.

1. CCS Is Not Adequately Demonstrated for Controlling CO_2 Emissions from Existing Coal-fired EGUs at 90% Capture Levels.

The final 2024 Carbon Rule identified only two full-scale demonstration projects to support its technical determination that CCS achieving 90% capture is adequately demonstrated. One was the Boundary Dam CCS Project in Canada, which came online in 2014 as the world's first post-combustion CCS application at an existing lignite-fired generating unit owned by SaskPower. The other was the Petra Nova CCS Project that demonstrated for several years the feasibility of a post-combustion carbon capture system on an existing coal-fired EGU at the Parish Power Generating Station in Texas. The following review clearly shows that these two projects represent only an initial first step in the process for demonstrating that CCS is adequately demonstrated, and that successful completion of additional full-scale CCS projects is needed to demonstrate CCS can routinely achieve 90% capture levels during typical operating conditions at existing coal-fired EGUs nationwide.

Boundary Dam CCS Project. The Boundary Dam CCS Project came online in 2014 as the world's first post-combustion, coal-fired CCS project that was installed on one of the existing generating units at the Boundary Dam Power Station owned by SaskPower. SaskPower installed a post-combustion capture system using an amine solvent that was designed to capture up to 90%, or one million tons of CO_2 emissions annually from a unit burning lignite coal with a nameplate generating capacity of 139 MW and a net output of 115 MW.[34]

As one would expect with a "first-of-a-kind" (FOAK) demonstration project, the Boundary Dam CCS Project encountered multiple design problems relating to various aspects of the capture system, such as contamination of amine chemistry and operation of the CO_2 capture system. These problems contributed to increases in the operating costs of the CCS technology and the decision by SaskPower to cancel its plans to install the same capture systems on other coal-fired EGUs located at the Boundary Dam facility.

These challenges clearly indicate that carbon capture systems are still evolving and are not ready for broad commercial deployment. Further engineering and other technical work are needed through additional CCS demonstration projects to resolve those design and operational challenges, as well as to better understand the integration

[34] *See* Adam Duckett, *The Privilege of Being First, The Chemical Engineer* (May 1, 2018), available here.

of carbon capture operations with full-scale commercial applications at electric generating facilities. Addressing these design and technical matters through additional demonstration projects is therefore necessary before CCS can be considered ready for deployment as a commercially available technology under a wide range of full-utility scale applications and operating conditions.

Petra Nova CCS Project. NRG Energy, Inc. (NRG) developed and brought online for a three-year-demonstration period (2017-2019) the Petra Nova CCS Project at its Parish Power Generating Station in Texas. The objective of this project was to demonstrate the performance of a post-combustion CCS technology that is designed to capture up to 90% of the CO_2 emitted from a partial (240 MW) flue gas stream from existing Unit 8 at the Parish facility, which has a nameplate capacity of 654 MW. When Petra Nova operated at full capacity, it was successful in achieving for limited periods of time a 90% capture rate of the CO_2 emissions from the flue gas that was directed to the capture unit. However, due to outages and derates of the capture plant over the three-year demonstration period, the actual capture rates ranged from about 60% to 80%.[35] Given that this was a partial application of CCS, the Petra Nova CCS Project had the capability to treat only about 37% of total CO_2 emissions from Unit 8 and thereby achieve a 33% reduction in the total CO_2 emissions from Unit 8.[36] These performance levels are well below the performance standard requiring a continuous 90% capture level and achieving an 88.4% reduction in a unit's existing CO_2 emission rate on an annual basis. This performance and operational data demonstrate the need for additional testing to improve performance levels, reliability, and cost-effectiveness.[37]

Finally, it should be noted that the 2024 Carbon Rule refers to a few other past small-scale CCS projects in support of its determination that CCS technologies may be adequately demonstrated.[38] None of these small pilot projects provide a separate basis for determining that CCS is adequately demonstrated. At most, those few small, pilot-

[35] *See* DOE, Final Technical Report, W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project (Mar. 31, 2020) (Final Technical Report), available here.

[36] *See* Energy Information Administration, *Petra Nova is one of two carbon capture and sequestration power plants in the world* (Oct. 31, 2017) (Petra Nova EIA Overview), available here.

[37] Notably, the Petra Nova Project has several important design parameters that are significantly different from the typical application of a carbon capture system on a coal-fired EGU. Most importantly, NRG had to uniquely design the post-combustion carbon capture system to avoid the integration of the thermal load of the capture technology into the boiler steam cycle of the existing coal-fired generating unit at the Parish Power Generating Station. Instead of using the existing unit's steam and power, NRG built an entirely new and separate 75 MW cogeneration unit to supply the parasitic electrical and steam load for the operation of the carbon capture system. This design is not something that can be widely replicated at coal units across the country.

[38] Examples of such small CCS pilot projects upon which EPA relied in the Carbon Rule include the Warrior Run plant in Maryland, which captured 10% of the unit's CO_2 emissions (about 110,000 metric tons of CO2 per year) and Shady Point plant in Oklahoma, which captured a 5% slipstream (about 66,000 metric tons of CO_2 per year).

scale projects have shown only that CCS may be a potentially viable technology for controlling CO_2 emissions from coal-fired EGUs at some indeterminant point in the future. Further work is clearly necessary to demonstrate the effectiveness, reliability, and affordability of CCS in full-scale utility applications for a variety of coal-fired EGU facilities under real-world operating scenarios.

2. The Installation and Operating Costs of CCS Are Excessive and Therefore CCS Is Economically Infeasible.

In the Proposed Rule, EPA correctly acknowledges the excessively high costs to install and operate CCS control systems. These exorbitant costs establish a separate and independent legal basis for the Agency to repeal the CCS-based performance standard under the Alternative Proposal even if CCS was determined to be technically feasible (which is clearly not the case). Courts have affirmed on multiple occasions that EPA may not adopt performance standards that impose capital and operating costs determined to be "exorbitant,"[39] "greater than the industry could bear and survive,"[40] "excessive,"[41] or "unreasonable."[42] Furthermore, EPA has repeatedly acknowledged that any control system cannot be considered BSER if it is too costly because such unreasonable or excessive costs would indicate that the system in question is not the "best."[43]

The economic infeasibility of CCS is reflected by the extremely high actual costs incurred by the first wave of government-funded CCS demonstration projects that were undertaken at Boundary Dam and Petra Nova. As discussed below, not even substantial governmental funding was sufficient to offset the extremely high costs incurred by the CCS projects.[44]

Boundary Dam CCS Project. SaskPower reported capital costs for the Boundary Dam CCS Project that were more than five times the amount that EPA estimates for a CCS retrofit project at an existing coal-fired power plant. Boundary Dam's reported capital cost for retrofitting CCS components at an existing EGU was $11,300 per kilowatt (kW),

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[39] *Lignite Energy Council*, 198 F.3d at 933.
[40] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975).
[41] *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).
[42] *Id.*
[43] *Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 83 Fed. Reg. 65,424, 65,433 (Dec. 20, 2018); *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 1430, 1464 (Jan. 8, 2014).
[44] This same situation applies today with respect to federal subsidies that are available for future CCS projects under Section 45Q of the Internal Revenue Code. Set at $85 per ton of CO_2 captured and permanently stored in underground saline formations or used for enhanced oil and gas recovery, this government subsidy is insufficient to offset fully the excessively high costs of capturing, transporting, and permanently storing the CO_2 emissions in such geological formations.

as compared to EPA's own retrofit capital cost estimates of $2,222 per kW based on a 400 MW unit. In addition, SaskPower has also incurred substantial additional costs to remedy design flaws and operational problems, such as Boundary Dam's amine solvent-based process used for extracting CO_2 from the flue gas stream.[45] These operational problems reduced the availability of the Boundary Dam CCS system due to more frequent cleaning required for the CCS components. In particular, the CCS system initially had to be taken offline every four to five weeks to remove the fly ash that was adhering to surfaces. While this problem has generally been addressed at this FOAK project, it further underscores that additional demonstrations of carbon capture operating at commercial-scale electric utility projects are necessary to identify and develop solutions to overcome these types of challenges.

To help offset these high costs, the project was supported with a C$250 million grant from the Canadian government, which was necessary for the project to be constructed. This financial subsidy amounted to approximately 20% of the total project cost.[46] In addition, the project relies on revenue from sales of the captured CO_2 for use in enhanced oil recovery (EOR).[47] These revenue streams may not be available for other CCS projects that electric utilities might undertake to comply with the CCS performance standard under the Carbon Rule.

Petra Nova CCS Project. Another FOAK project is the Petra Nova CCS Project, which would not have been financially viable without substantial government subsidies received from the Department of Energy (DOE) under its Clean Coal Power Initiative, a cost-sharing partnership between DOE and industry intended to demonstrate advanced coal-based power generation technologies at commercial scale. In addition to this DOE funding, Petra Nova received a loan sponsored by the Japan Bank for International Cooperation, and received additional revenues by selling the captured CO_2 for EOR use and from producing and selling oil (Petra Nova is a part owner of the related oil field operation). These additional revenue streams were essential to offset a significant portion of the substantially higher costs to build and operate this FOAK application of the post-combustion CCS technology. The Japanese government-supported loan financing the project was also necessary, as there are no commercial financing tools available for CCS projects. Since these additional revenue streams and government-supported project finance tools are unique to the Petra Nova CCS Project and likely cannot be replicated at

[45] These operational problems (and resulting additional costs) were caused by high flue gas temperatures and particulate content that interfered with and effectively contaminated the amine chemistry of the CO_2 capture system used at Boundary Dam facility. *See* Duckett, *supra* note 34.
[46] Coal Industry Advisory Board, *An International Commitment to CCS: Policies and Incentives to Enable a Low-Carbon Energy Future*, at 19 (Nov. 21, 2016).
[47] *Id.*

most other carbon capture projects on a national level, those revenue streams cannot be used to demonstrate the economic feasibility of deploying CCS technology.

It is important to note that just like the Boundary Dam CCS Project, the reported capital costs for the Petra Nova CCS Project were also much higher than EPA's current estimates for CCS retrofits in the 2024 Carbon Rule, according to the Energy Information Administration (EIA).[48] The retrofit cost was reported to be $1 billion, or $4,200/kW, which is about 90% higher than EPA's estimate of $2,222/kW based on a 400-MW unit. Before CCS with 90% CO_2 capture can be considered a cost-effective BESR control technology, additional demonstration projects will be necessary to build on the lessons learned from this first wave of projects — to increase efficiency, and to reduce the capital and operational costs of CCS technology.

3. 90% CCS Capture of the CO_2 Emissions Is Not Achievable.

The 2024 Carbon Rule established a performance standard for existing long-term, coal-fired EGUs that requires the CCS control system to achieve a 90% capture of the CO_2 emissions from the entire flue gas on a continuous annual basis. For the reasons discussed below, such a stringent performance standard is not achievable and therefore provides another independent ground for EPA to repeal the performance standard under the Alternative Proposal.

First, courts have interpreted the statute to require EPA to set a CO_2 performance standard that can be achieved by all affected EGUs at all load levels operating under the full range of foreseeable conditions in all parts of the country. While some CCS projects have been designed to achieve 90% capture levels for short periods of time, no CCS demonstration project has been able to continuously achieve 90% capture levels on an average annual basis under the full range of prevailing operating conditions. Based on long-standing court precedent, EPA has a mandatory legal obligation to set CO_2 performance standards at levels that are achievable in practice "under the range of relevant conditions which may affect the emissions to be regulated,"[49] including "under most adverse conditions which can reasonably be expected to recur."[50]

Second, CCS demonstration projects have consistently failed to meet this statutory requirement for achievability. For example, as discussed above, the Petra Nova CCS Project involved *partial* application of CCS to only a 240-MW flue gas slip stream of existing Unit 8 at the Parish facility with a nameplate capacity of 654 MW. As a result, the

[48] *See* Petra Nova EIA Overview, *supra* note 36.
[49] *Nat'l Lime Ass'n*, 627 F.2d at 433.
[50] *Id.* at 431 n.46.

Petra Nova Project had the capability to treat only about 37% of total CO_2 emissions from Unit 8 and thereby achieved only a 33% reduction in the total CO_2 emissions from Unit 8.[51] Such CO_2 capture levels are well below the 90% capture level mandated by the 2024 Carbon Rule. Similarly, the Boundary Dam CCS Project has failed to achieve 90% capture levels consistently over an annual operating period. A 2024 report issued by the Institute for Energy Economics and Financial Analysis found that the long-term CO_2 capture rate through the end of 2023 was approximately 57%, which is less than two-thirds of the 90% capture target for this CCS demonstration project.[52] The establishment of an unachievable performance standard for CCS provides another regulatory basis for EPA to repeal the CCS performance standard for existing long-term, coal-fired EGUs.

4. A Compliance Deadline of 2032 Is Not Achievable.

The amount of time necessary to develop a CCS project from start to finish is highly variable and will be contingent upon a wide range of determining factors unique to each project. However, what is certain is that an electric utility cannot develop and deploy a fully integrated CCS system and begin to comply with the applicable CO_2 performance standard by January 1, 2032, under any circumstances. This compliance deadline is not only unachievable for new CCS projects that have not yet begun project development, but also those projects for which electric utilities may have performed a comprehensive Front-End Engineering Design study and completed other preliminary technical work for the design and development of the CCS project prior to the issuance of a final rule.

Although the exact timeframe is uncertain because CCS has not been commercially deployed, it is reasonable to expect that as much as eight to ten years will be needed to design, construct, and bring a new CCS facility online. This additional time is necessary to complete the major essential elements of the project, including the design, engineering, planning, permitting, fabrication, and installation of the CCS technology for capturing the CO_2 emissions from the coal-fired EGU. Furthermore, long-lead times will likely be necessary for development, siting, permitting, and construction of the pipeline that will transport the CO_2 captured by CCS equipment and for obtaining Underground Injection Control Class VI permits and pore space for the injection and long-term storage of the captured CO_2 in an underground geologic formation.

[51] *See* Petra Nova EIA Overview, *supra* note 36.
[52] Global Energy Monitor, Boundary Dam power station § 7*,* available here.

B. 40% Natural Gas Co-Firing Is Neither Cost-Effective Nor Technically Achievable.

Major problems exist with the performance standard that the 2024 Carbon Rule set based on 40% natural gas co-firing for intermediate-term coal-fired power plants. As discussed below, a standard requiring 40% natural gas co-firing is neither a cost-effective control option nor technically achievable by the applicable compliance date of January 1, 2030. These flaws provide a technical basis for the repeal of the 40% natural gas co-firing standard.

Natural gas co-firing at such high levels is not cost-effective. The Agency significantly underestimated natural gas prices and failed to consider other related fixed fuel costs that an electric utility must incur to reliably co-fire large amounts of natural gas with coal. This significant underestimation of the price differential between the delivered costs of natural gas and coal skews EPA's cost analysis for justifying the cost-effectiveness of a coal-fired unit co-firing 40% natural gas.

Moreover, 40% natural gas co-firing is technically infeasible. EPA significantly underestimated the time necessary to complete the design, permitting, and construction of a natural gas lateral pipeline and the boiler conversion work. The Agency's estimate of approximately 3½ years is far too optimistic, especially considering the many permit approvals and environmental reviews that are required prior to construction.

Finally, courts have ruled on multiple occasions that CAA section 111 does not authorize EPA to adopt performance standards that would have the effect of "redefining" the source. This prohibition against the redefinition of the source clearly barred EPA from adopting the performance standard requiring coal plants to co-fire natural gas at an annual capacity factor of 40%. This legal flaw provides another basis in support of the proposal to repeal this performance standard applicable to existing, medium-term coal-fired EGUs under the 2024 Carbon Rule.

V. THE PROPOSED RULE ESTABLISHES A STRONG TECHNICAL BASIS FOR REPEALING THE PHASE 2 PERFORMANCE STANDARDS FOR NEW BASELOAD COMBUSTION TURBINES.

The final Carbon Rule established stringent CO_2 performance standards for new natural gas stationary combustion turbines that are codified at Subpart TTTTa of the New Source Performance Standards (NSPS) regulations. Those standards include a Phase 2 performance standard requiring new baseload combustion turbines (having an annual capacity factor above 40%) to achieve by 2032 an NSPS limitation requiring 90% capture of the CO_2 emissions from the entire flue gas stream. As discussed previously, EPA

should repeal the Phase 2 performance standard for new baseload combustion turbines given that CCS achieving 90% capture clearly does not meet the BSER requirements mandated by the statute. These key reasons are reviewed below.

First and foremost, CCS with 90% capture is neither adequately demonstrated nor achievable by new baseload combustion turbines. The Proposed Rule contains extensive documentation of the many reasons why CCS fails to meet these statutory requirements for BSER and therefore must be repealed.[53]

In addition to the analysis documenting these technical shortcomings, several other important reasons support the repeal of CCS as BSER for baseload combustion turbines. CCS has never been applied to the entire flue gas stream of a natural gas combustion turbine facility. Even if CCS was determined to be adequately demonstrated (which is not the case), the load cycle and fluctuating output levels of typical baseload combustion turbines would prevent the continuous and efficient operation of the CCS control system that would be necessary for achieving the 90% capture levels that the Carbon Rule required on a continuous basis over an annual period. The CCS performance standard is therefore fundamentally incompatible with the operational duties and functions that baseload natural gas combustion turbines must perform to ensure electric grid reliability. Those duties and functions require natural gas-fired combustion turbines (including the larger combined-cycle plants) to operate as load-following units with the capability of rapidly starting and ramping up the units to match electric supply with demand.

Furthermore, the Proposed Rule contains extensive documentation of the many reasons why the infrastructure necessary for deploying CCS on both coal-fired and gas-fired EGUs (including the construction of pipelines and CO_2 injection wells) cannot be deployed by the 2032 compliance deadline.[54] These alone provide grounds supporting EPA's proposed determination that the Phase 2 standards based on CCS for baseload combustion turbines are not achievable.

Further, EPA made Inflation Reduction Act ("IRA") funding a linchpin of its BSER cost-effectiveness determination, and any materially adverse impacts on IRA funding will render that determination unsupported. For example, EPA asserted that by 2030-2040, funding from programs established under the IRA would have decreased costs, and enabled construction of needed infrastructure such as low-GHG hydrogen production

[53] See Proposed Rule, 90 Fed. Reg. at 25,775-77(discussing the many technical deficiencies in the BSER analysis for new baseload combustion turbines under the 2024 Carbon Rule).
[54] *Id*. at 25,772-73 (discussing the technical deficiencies in the cost analysis for existing coal-fired EGUs); *id.* at 25,776-77(discussing the technical deficiencies in the cost analysis for new baseload combustion turbines).

hubs, CCS projects, pipelines to transport captured CO_2 and hydrogen, and additional transmission resources.[55] However, much of this funding was changed or removed in 2025 with passage of the One Big Beautiful Bill Act,[56] rendering the underlying assumptions supporting the Phase 2 standards invalid. Future funding of remaining IRA subsidies remains in doubt. The practical result being an invalidation of the Phase 2 standards because EPA cost-effectiveness evaluations relied on grants and other financial mechanisms that are no longer available.

Each of these reasons individually is a fatal flaw to the BSER analysis that EPA performed in the final Carbon Rule for setting the Phase 2 performance standard for new baseload combustion turbines. Given that CCS with 90% capture is neither adequately demonstrated nor achievable by new baseload combustion turbines, EPA clearly has strong grounds for repealing that standard based on the factual record established under the Proposed Rule.

VI. THE PHASE 1 PERFORMANCE STANDARDS FOR NEW INTERMEDIATE LOAD AND BASELOAD COMBUSTION TURBINES ARE UNACHIEVABLE AND THEREFORE MUST BE REPEALED OR REVISED UNDER THE ALTERNATIVE PROPOSAL.

The annual CO_2 emissions rates achievable by new stationary combustion turbines will depend on both operational and site-specific factors that are largely beyond the control of power plant operators. The purpose of this section is to provide a review of those factors that will reduce the generating efficiency of the combustion turbine and thereby increase its CO_2 emissions rate on a CO_2 pounds-per-megawatt-hour basis. Furthermore, EPA's failure to consider and account for these factors in the 2024 Carbon Rule has resulted in EPA setting CO_2 performance standards that are not achievable by either intermediate-load or baseload combustion turbines under the full range of recurring real-world operating conditions that many (if not most) new combustion turbines must now operate.

Those CO_2 performance standards are codified at Subpart TTTTa of the NSPS regulations and set CO_2 emission limitations of 1,170 pounds CO_2/megawatt-hour (MWh)-gross for intermediate-load turbines (with annual capacity factors between 20% and 40%) and 800 pounds CO_2/MWh-gross for baseload turbines (with annual capacity factors at or above 40%). Generally referred to as "Phase 1" performance standards, they set CO_2 emission limitations based on highly efficient turbine technologies and apply immediately upon startup of the affected intermediate-load or baseload turbine facility.

[55] Inflation Reduction Act of 2022, H.R. 5376, 117th Congress (2021-2022) (as amended by the Senate).
[56] H.R. 1, 119th Congress (2025-2026).

As explained previously, the statute requires the Agency to demonstrate that all performance standards established under CAA section 111 are achievable across the full range of operating conditions, including the "most adverse conditions which can reasonably be expected to recur."[57] To comply with this clear statutory mandate, EPA has a legal duty to remedy this major technical flaw that has resulted in the final Carbon Rule establishing overly stringent CO_2 emissions limitations that are not achievable for new intermediate-load and baseload combustion turbines under the typical range of recurring operating conditions.

The most practical way for EPA to remedy this fundamental flaw is for the Agency to repeal the Phase 1 performance standards based on a determination that the standards are not achievable and therefore are in violation of the statute. Such a full repeal of the Phase 1 standards can be expeditiously adopted as part of this rulemaking when the Agency issues a final rule repealing all of the other performance standards under the Alternative Proposal (which EPA expects to complete by the end of this year). Taking prompt action to repeal the Phase 1 standards (along with the Phase 2 CCS standards) within such an expeditious timeframe is the best and most effective way for EPA to remove the substantive regulatory uncertainties that could delay permitting, construction, and deployment of new combustion turbines. The removal of these potential regulatory delays and barriers is therefore critically important to allow electric utilities to bring online additional dispatchable combustion turbine capacity needed to meet sharp increases in electricity demand nationally and ensure electric grid reliability.

If the prompt repeal of the Phase 1 performance standards is not possible, the next best option is for EPA to change from an annual standard-based compliance approach to a manufacturer's certification program, similar to the program applicable to Tier IV diesel engines or non-road engines. In such a program, manufacturers would certify that their combustion turbine models are able to meet certain emissions or efficiency standards. EPA already has a great deal of experience in developing, implementing, and operating certification programs for reciprocating internal combustion engines, and combustion turbine *engines* can fit squarely into that same framework.

An EPA turbine certification program could also eliminate having to account for several of the issues discussed in greater detail below that are largely beyond the control of turbine manufacturers (e.g., site-specific temperature and barometric pressure regimes) and of turbine owners and operators (e.g., output fluctuations to follow variations in demand from load and supply from intermittent renewable resources). One simple approach would be for EPA to require manufacturers to certify that their turbines be designed to meet CO_2 emission rates at 100% load and standard temperature and

[57] *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46.

pressure conditions. EPA would then be assured that manufacturers are producing highly efficient combustion turbines designed to minimize CO_2 emissions, and turbine owners and operators would not have to overbuild generation, operate at reduced load levels, or install turbines that may not be fit for purpose simply to meet continuous annual emission standards that are largely out of their control.

Failing outright repeal or, alternatively, implementation of a certification program, EPA should initiate a supplemental rulemaking that revises those overly stringent CO_2 emissions limitations that are not achievable for many new intermediate-load and baseload combustion turbines under the typical range of recurring operating conditions. EPA should initiate this supplemental rulemaking as soon as possible in third-quarter 2025 so that a final rule revising those Phase 1 performance standards is promulgated as early as possible in 2026.

In support of this approach for addressing major shortcomings with the Carbon Rule, the discussion below provides a detailed review of major technical deficiencies that explains why the current Phase 1 performance standards are not achievable for new intermediate-load and baseload combustion turbines under the typical range of recurring operating conditions. To correct these problems, EPA must repeal those standards or implement a turbine-certification program, and if neither of those approaches are possible, initiate a supplemental rulemaking to revise those standards.

A. Operational and Site-Specific Factors Have Major Effects on the CO_2 Performance Levels of New Stationary Source Combustion Turbines.

The following discussion provides a detailed review of the operational and site-specific factors that will reduce the generating efficiency of the combustion turbine and thereby increase its CO_2 emissions rate on a CO_2 pounds-per-MWh basis. These factors include the load level and operating profile of the turbine unit, ambient temperature, and the use of duct burners, as well as various operating and design characteristics that may affect turbine efficiencies. This review provides a compelling technical basis supporting the conclusion that the current standards of 1,170 pounds CO_2/MWh-gross for intermediate-load turbines and 800 pounds CO_2/MWh-gross for baseload turbines are not achievable for most combustion turbines under recurring, real-world conditions.

1. Reduced and Fluctuating Load Levels Have the Greatest Impact on Both Turbine Efficiencies and CO_2 Emission Rates.

In setting the CO_2 performance standards for new combustion turbines under the Carbon Rule, EPA assumed that combustion turbines typically operate at or near full-load and then shut down when they are no longer needed to meet electricity demand. But most

turbine units do not operate in such a binary manner. Nor do they operate as stable baseload units at maximum production levels where they can optimize efficiencies and minimize their CO_2 emissions rates. Rather, combustion turbines frequently operate at a variety of load levels to meet fluctuating electricity demand and serve a variety of important functions necessary for maintaining electric grid stability.

Operating a combustion turbine in this fashion significantly reduces its generating efficiency and increases the turbine's emissions rate on a CO_2 pounds-per-MWh basis. In effect, combustion turbines dispatched at reduced and fluctuating load levels operate below their optimally efficient performance levels and thereby can substantially increase their emissions rates on a CO_2 pounds-per-megawatt-hour basis to levels exceeding the applicable performance standards.

The following discussion provides a brief review of the operating characteristics that will effectively prevent most new combustion turbines from meeting the Phase 1 CO_2 performance standards under a wide range of typical real-world operating conditions. Notably, many of these operating characteristics are determined by factors that are largely beyond the control of individual electric utility operators. As described below, these factors are dictated by the evolving role that combustion turbines play in providing reliable, dispatchable, clean, and affordable electricity and ancillary services to power the electric grid.

- *Firming and Integrating Renewable Energy*. Combustion turbines are increasingly called upon to provide grid-firming or renewable-firming capacity. This role requires that combustion turbines quickly ramp up or down to compensate for the intermittent nature of renewable energy sources (wind and solar), thus balancing the grid and ensuring grid reliability. As these renewable sources become even more prevalent, turbine units will be expected to perform the critically important role of helping to balance the grid by compensating for the variability of renewable generation.

- *Maintaining Grid Stability*. Combustion turbines are now frequently operated at intermediate and minimum loads to maintain electric grid stability. Their rapid startup and load-following capabilities allow combustion turbines to serve as backup generation, ensuring grid reliability when other power sources are unavailable or cannot adjust quickly enough to fluctuating demand. Operating at less-than-full or high-load levels, combustion turbines play an important role in maintaining grid stability when renewable generation or other dispatchable thermal energy resources are unavailable to meet electricity demand for reasons that are beyond the control of their operators. This trend will only continue to grow.

- *Startups and Shutdowns*. Another growing trend is the increased number of times that combustion turbines start up and shut down each day. Turbine efficiencies decrease and emission rates increase during startups and shutdowns due to suboptimal combustion conditions that occur when reduced fuel-air mixing causes incomplete combustion.

- *Operating at Partial or Minimum Loads*. Similar turbine inefficiencies result from operating combustion turbines at partial or minimum stable load levels for extended periods of time. For example, combustion turbines can operate at minimum stable loads — typically around 40% to 50% of full output for environmental compliance — allowing output to be adjusted as required by grid operators. Such flexibility in generator output is necessary to balance the variable output of renewable resources and respond to rapid changes in demand. Electric utilities, for example, frequently may need to "park" their combustion units at these minimum stable load levels overnight to avoid a start-up-and-shutdown cycle to be available to respond to a forecast drop in wind generation or demand that requires maximum power generation the following morning. Similarly, it may be necessary for electric utilities to park their turbine units at reduced load during the middle of the day when increased solar generation is meeting a significant portion of the daytime demand. Each of these operating conditions prevents combustion turbines from operating continuously under optimal baseload conditions that would maximize generating efficiencies and minimize CO_2 emissions rates.[58]

In conclusion, combustion turbines are designed to generate electricity under a wide range of operating modes to meet electricity demand and maintain grid reliability. When they are not operating at or near full load, reduced efficiency will substantially increase CO_2 emission rates on a CO_2 pounds-per-MWh basis to levels exceeding the applicable performance standards.

2. High Ambient Temperatures Significantly Lower Turbine Efficiencies and Increase CO_2 Emission Rates.

Combustion turbines are more efficient at lower temperatures and less efficient at higher temperatures, with the amount of variation in efficiency depending on turbine type

[58] Although not a factor that reduces load levels, it should be noted that electric utilities frequently use duct burners with combined-cycle combustion turbines to meet sharp, short-term increases in electricity demand. As discussed below in greater detail, duct burners can rapidly increase generation from the combined-cycle facility by providing supplemental firing in the heat recovery steam generator (HRSG), thereby quickly boosting both steam production and output from the steam turbine. While duct burners increase total output from the facility, the incremental electricity is generated less efficiently than the electricity generated by direct fuel combustion in the turbine and the recovery of the waste heat by the HRSG.

and operating conditions. As a rule of thumb, every increase of 10 ºC in ambient temperature reduces the turbine thermal efficiency by about 1%. The annual nationwide CO_2 performance standard must reflect site ambient temperature variations over a twelve-month period to assure the achievability of that standard. In addition, a performance standard achievable by all new affected turbine units nationwide must reflect variations in turbine performance due to other temperature-related factors.

3. Permanent Degradation in Turbine Efficiency Is Another Important Factor That Should Be Reflected in the Performance Standard.

Turbine manufacturers quote performance levels that are based on "new and clean" conditions that do not reflect the degradation of a new combustion turbine that may occur over time due to mechanical, chemical, and environmental factors. All combustion turbines experience a certain amount of degradation even if they are well maintained. For a well-maintained turbine, a total efficiency loss of about 2% can be expected by end-of-life, even with regular major overhauls.[59] This permanent degradation in turbine efficiency must be reflected in the Agency's CO_2 performance standards to ensure the achievability of those standards over the full life of the turbine.

4. Duct Burners Can Significantly Increase Generation Output But Lower Turbine Efficiencies and Increase CO_2 Emissions Rates.

Most combined-cycle combustion turbine facilities in the United States (about 75% or 219 gigawatts of total installed combined-cycle generating capacity) operate with duct burners.[60] Major operational advantages of duct burners include enabling rapid increase in power output and supporting renewable integration by providing fast-response capacity to fill sharp drops in generation due to sudden reductions in intermittent renewable generation or steep variations in demand. While duct burners provide these important operational advantages, the overall thermal efficiencies of combined-cycle facilities will nonetheless decrease during duct-firing. These decreases in efficiencies will be as high as 6% to 8%, as compared to steady baseload operation without supplemental duct burner firing.

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[59] Vedran Mrzljak et al., *Analysis of Gas Turbine Operation Before and After Major Maintenance*, J. Mar. & Transp. Sci. (Dec. 2019), available here.

[60] EIA, *Most combined-cycle power plants have duct burners that add energy to the turbine exhaust* (June 15, 2022), available here. Currently, total combined-cycle generating capacity is over 292,000 MW as of 2024, with approximately 219,000 MW of this generating capacity equipped with duct burners. Mark Morey, *The U.S. combined-cycle gas turbine (CCGT) fleet is large and diverse* (Apr. 10, 2025), available here.

Notably, EPA did not reflect the widespread use of duct burners in setting the CO_2 performance standards for new combined-cycle combustion turbines under the Carbon Rule. This failure provides another compelling basis for concluding that the performance standards established under the Carbon Rule are not achievable.

B. Performance Data Demonstrates That Most Types and Sizes of Combustion Turbines Cannot Meet the Applicable Performance Standards Under Typical Real-World Operating Conditions.

The CO_2 emissions rates achievable by combustion turbines under real-world operating conditions are much higher than the CO_2 performance standards set for both intermediate-load, simple-cycle combustion turbines and baseload combined-cycle combustion turbines under the Carbon Rule. The reasons for these higher CO_2 emissions rates are the operational conditions and other site-specific factors discussed above that reduce the generating efficiencies of combustion turbines and thereby increase their CO_2 emissions rate on a CO_2 pounds-per-megawatt-hour basis. As discussed in the prior section, these factors include reduced load levels, cycling and fluctuations in electricity output, frequency of startups and shutdowns, high ambient temperatures, degradation in efficiency, and the use of duct burners.

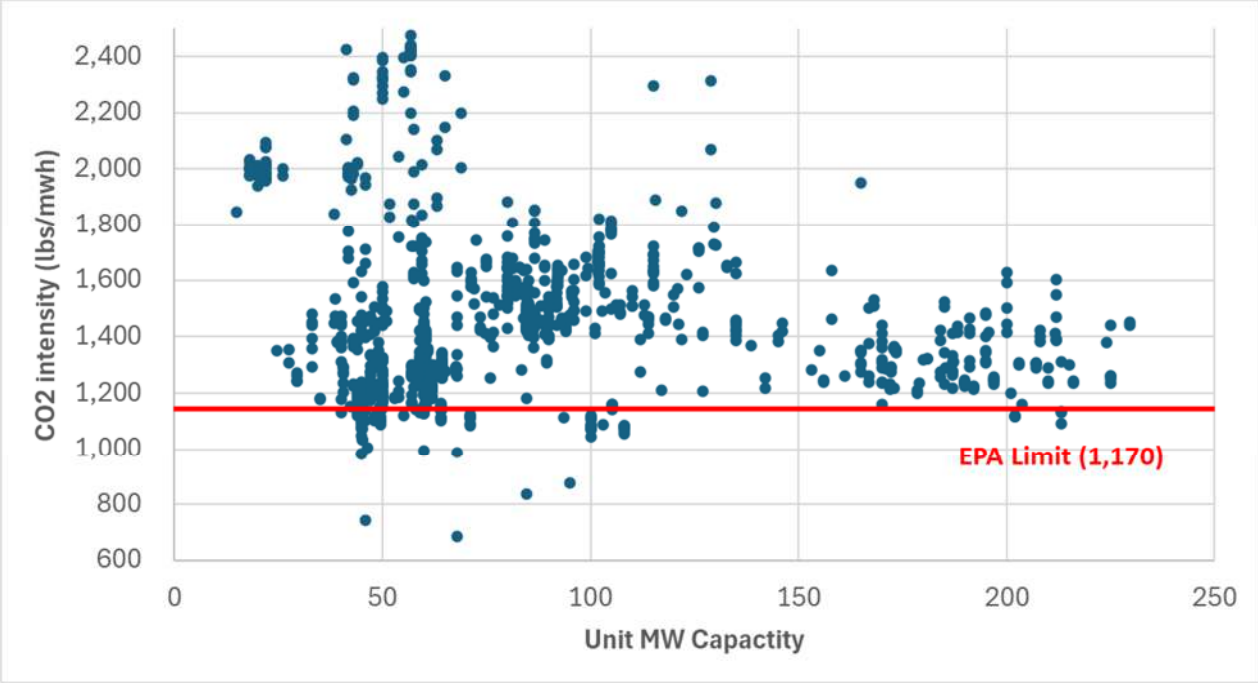
The discussion below provides a detailed review of performance data on the actual CO_2 emissions rates being achieved by combustion turbines. The review of this performance data demonstrates that most types and sizes of combustion turbines cannot meet the applicable current CO_2 performance standards under the typical real-world operating conditions identified in the preceding subsection. The review is based on an analysis of CO_2 emissions data collected by EPA's Clean Air Markets Division (CAMD), which provides highly granular data on the hourly CO_2 emission rates achieved by all affected EGUs (including simple-cycle combustion turbines) based on EPA-certified continuous emissions monitoring systems (CEMS).

1. Actual CO_2 Emission Rates Achieved by Simple-cycle Combustion Turbines Exceed the Phase 1 Performance Standard for Intermediate-load Combustion Turbines.

An analysis of recent emissions rate data from simple-cycle combustion turbines clearly demonstrates that simple-cycle turbines cannot comply with the 1,170 pounds CO_2/MWh standard under a wide range of real-world operating conditions. One turbine manufacturer reviewed 2024 CEMS emissions data from EPA's CAMD for units installed

between 2017-2023.[61] As depicted in Chart 1, only 15% of the existing simple-cycle combustion turbines installed between 2017 to 2023 were at or below the applicable 1,170 pounds CO_2/MWh standard when operating under real-world conditions. The units with emissions levels meeting the standards are not necessarily more efficient but, at least in some cases, simply reflect more favorable operating conditions.

Chart 1
2024 Actual Annual CO_2 Performance Levels
Simple-Cycle Combustion Turbines



Source: EPA CAMD CEMS Data

This actual performance data therefore demonstrates the remaining 85% of the existing reasonably new (installed between 2017-2023) national fleet of simple-cycle combustion turbines did not meet the current performance standard for intermediate-load turbines. No significant major technological advancements to improve simple-cycle turbine performance have occurred that would cause more recent turbines to perform better than turbines installed between 2017-2023. Nor are any major advancements in generating efficiency expected in the foreseeable future.

This performance data generated by the turbine manufacturers demonstrates that a significant portion of the affected simple-cycle combustion turbines cannot meet a performance standard set at 1,170 pounds CO_2/MWh under recurring, real-world

[61] This emissions data included 131 simple-cycle turbines operating in 2024, of which the data for 127 turbine units had valid data included in the analysis.

conditions. Setting such a stringent national standard that only a relatively small portion of affected turbines can meet, and only under optimal operating conditions, clearly violates the BSER mandate of CAA section 111.

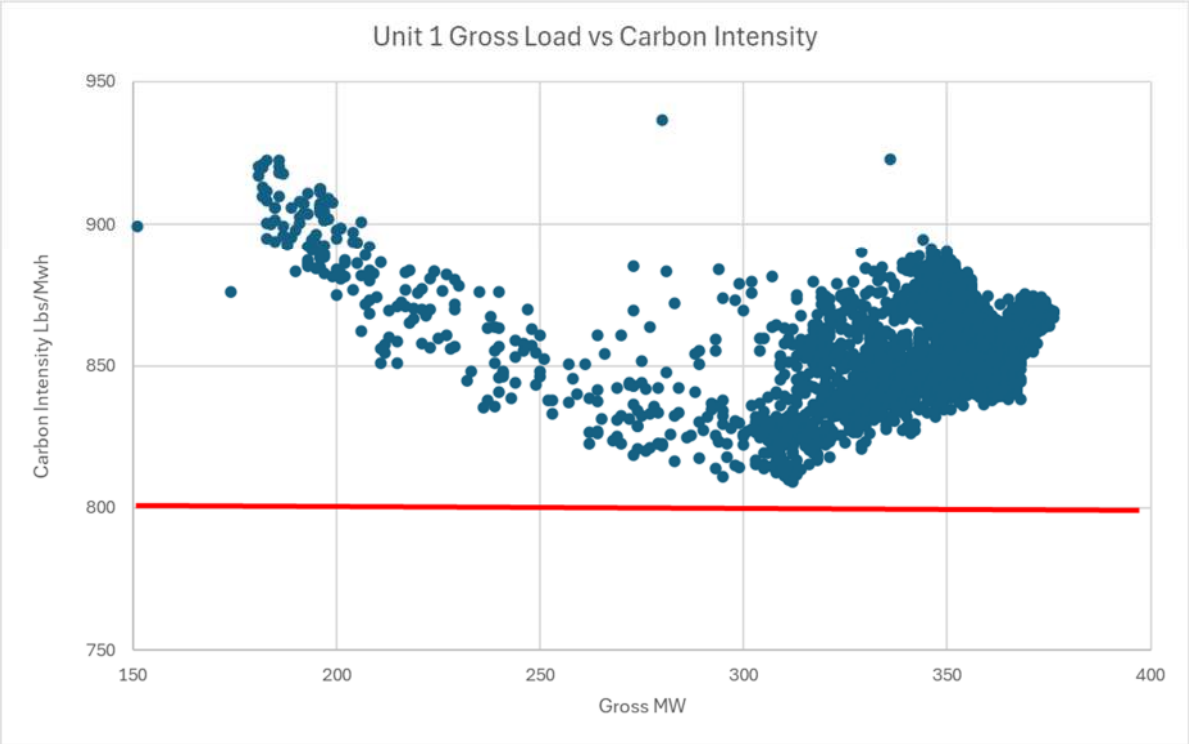
2. Actual CO_2 Emission Rates Achieved by Baseload Combustion Turbines Exceed the Phase 1 Performance Standard for Baseload Turbines.

A turbine manufacturer also completed a preliminary analysis of recent CEMS data from combined-cycle combustion turbines in EPA's CAMD database. That analysis also confirms the inability of combined-cycle turbines to achieve the 800 pounds CO_2/MWh standard under a wide range of real-world operating conditions. This analysis indicates that only 14% of the combined-cycle turbines (almost all H Class or J Class turbines) installed between 2017 to 2023 were able to meet the 800 pounds CO_2/MWh limitation under real-world operating conditions. In contrast, the remaining 86% of these combined-cycle combustion turbines cannot meet the current performance standard for baseload combustion turbines under the full range of reasonably foreseeable real-world operating conditions.

The unachievablity of the performance standard set is further illustrated by a review of the CO_2 CAMD CEMS data for a GE Verona 7F combined-cycle combustion turbine. This graphic in Chart 2 below indicates that a combined-cycle turbine operating for 7700 hours in 2024 could not achieve an emissions rate of 800 lbs. CO_2/MWh for even one hour at any load or operating conditions.

Setting the national standard so stringent that only a relatively small percentage of affected combined-cycle turbines can meet it clearly violates the BSER mandate of CAA section 111. That statutory mandate — as interpreted by the courts — requires EPA to set a standard that all affected combined-cycle combustion turbines nationwide must be capable of achieving in practice under a full range of reasonably foreseeable, real-world operating conditions.

Chart 2
2024 Actual Annual CO_2 Performance Levels
GE Verona 7F Combined-Cycle Combustion Turbine



In conclusion, the importance of EPA revising the performance standards for both intermediate-load and baseload combustion turbines cannot be overstated. No emissions control technologies exist for effectively and economically controlling CO_2 emissions from combustion turbines. As EPA itself has confirmed, neither carbon capture and sequestration nor combusting large amounts of hydrogen are technically and economically feasible control options for lowering CO_2 emissions from combustion turbines.

Given that non-compliance is not an option, both performance standards would greatly increase compliance costs and pose significant challenges for ensuring electric grid reliability. One compliance option would force electric utilities to operate their combined-cycle facilities at full load to maximize generating efficiencies and thereby lower CO_2 emissions from the facility. The other option would force electric utilities to overbuild their generating capacity to comply with the less-stringent CO_2 performance standards set for intermediate-load and low-load turbines. Such a regulatory outcome is not only an inefficient solution but also an unnecessary step toward minimizing CO_2 emissions from combustion turbines. Both turbine manufacturers and the electric power industry generally already have strong economic incentives to design, build, and operate the most-

efficient combustion turbines with the lowest CO_2 emissions to reduce fuel consumption and lower the overall costs of generating electricity.[62]

VII. The Final Rule Should Address Key Implementation Problems Posed by the Current CO_2 Performance Standards for New Combustion Turbines.

The 2024 Rule established stringent CO_2 NSPS limitations for new natural gas stationary combustion turbines that are unachievable for both baseload and intermediate-load turbine units. For example, those limitations (codified at NSPS Subpart TTTTa) set a Phase 2 performance standard for all new baseload turbines that requires 90% capture with CCS by 2032. Similarly, the NSPS Subpart TTTTa limitations set extremely stringent performance standards that apply during Phase 1 upon immediate startup of new combustion turbines. Those limitations are based on optimal turbine efficiency levels that set CO_2 emission limitations of 1,170 pounds CO_2/MWh-gross for intermediate-load turbines and 800 pounds CO_2/MWh-gross for baseload turbines, both of which are unachievable under typical turbine operating scenarios.

AMP has presented performance data and other technical information explaining why the 2024 Subpart TTTTa NSPS limitations are unachievable and describing what specific changes EPA should consider making to address the major operational and compliance problems posed by those standards. However, two major regulatory challenges to the prompt deployment of new combustion turbines will remain even if EPA repeals or revises the applicable limitations for baseload and intermediate-load turbine units under this rulemaking.

One regulatory challenge is an implementation problem that arises in the context of setting CO_2 emissions limitations based on the best available control technology (BACT) under the New Source Review (NSR) program. This implementation problem results from the CAA provision that expressly requires permitting authorities to set CO_2 BACT limitations no less stringent than the applicable CO_2 NSPS limitations through the NSR permitting process. This means that while the current NSPS limitations remain on the books (which will be at least through the end of 2025), these unachievable standards will be the minimum CO_2 control level floor for all BACT limitations now being set in pending NSR permits.

[62] Furthermore, it is important to note that while combustion turbines may operate at a lower efficiency (higher emissions rate in lbs. CO_2/MWh) when not operating at high loads, operations at lower loads are due to balancing their output with the output of intermittent renewables generation to meet demand. The renewables generation has zero emissions and combustion turbine operations at lower loads also have lower absolute CO_2 emissions (measured in lbs. CO_2/MWh) so overall CO_2 emissions are still greatly reduced and costs to customers are lower.

The second regulatory challenge is an implementation problem that results from current NSPS regulations that determine the applicability of newly adopted NSPS limitations. Those regulations could be interpreted to require that the current, overly stringent 2024 Subpart TTTTa limitations should apply to those turbine projects for which binding contracts have been executed for the fabrication and purchase of new combustion turbines. Given that many electric utilities are currently entering into binding contracts for combustion turbines needed to meet recent, unforeseen increases in electricity demand, those utilities arguably may remain subject to the current, more-stringent standards under the current NSPS applicability rules even if EPA repeals or lowers the stringency of those performance standards to achievable control levels pursuant to this rulemaking.

The discussion below provides a detailed analysis of these two implementation problems, which could impede the deployment of new baseload and intermediate-load combustion turbine generation while the 2024 Subpart TTTTa limitations remain in effect. This analysis is followed by a review of suggested options to address potential regulatory challenges through the issuance of national guidance.

A. EPA Should Issue National Guidance on Permissible Options for Setting the CO_2 BACT for New Combustion Turbines.

One key requirement imposed under the NSR permitting program is that all new combustion turbine facilities must meet stringent BACT emissions limitations for all NSR-regulated air pollutants. Permitting authorities must set those BACT limitations on a case-by-case basis for each new combustion turbine and, in so doing, may not set the BACT limitations at levels that are less stringent than the applicable NSPS limitations for the affected facility. In the case of CO_2 emissions, those minimum BACT limitations are the current Subpart TTTTa CO_2 limitations that EPA established for new combustion turbines in the 2024 Carbon Rule, so long as they remain in effect.

Many electric utilities are under pressure to build and bring online new combustion turbines as soon as possible to meet increased demand for electricity. These pressing needs for additional dispatchable generation are requiring electric utilities to obtain NSR permits authorizing the construction of new combustion turbines as soon as possible; they cannot wait until after EPA completes this rulemaking to initiate the permitting process.

Timing is the problem. So long as the 2024 CO_2 NSPS Subpart TTTTa limitations remain in effect, the CAA expressly requires that the CO_2 BACT limitations for new baseload turbines in 2032 not be less stringent than 90% capture through CCS. Similarly, the CO_2 BACT limitations upon immediate startup of the new combustion turbines must not be less stringent than the currently unachievable CO_2 NSPS limitations. Those Phase

1 NSPS limitations are 800 pounds CO_2/MWh-gross for baseload turbines and 1,170 pounds CO_2/MWh-gross for intermediate-load turbines. As discussed above, EPA set those limitations based on highly efficient combustion turbines operating under optimal conditions that are practically unrealistic to achieve for most, if not all, new combustion turbines to meet over an annual operating period.

Solution to the CO_2 BACT Permitting Problem. EPA should issue national guidance clarifying how permitting authorities may issue CO_2 BACT limitations based on the possible future repeal of the current 2024 NSPS Subpart TTTTa rules for controlling CO_2 emissions. The overall objective of this approach would be to allow the establishment of one CO_2 BACT limitation that complies with the CAA requirement that the CO_2 BACT limitation is not less stringent than the current applicable CO_2 NSPS limitation (which may be revised or repealed by EPA). The most straightforward way to ensure compliance with this CAA requirement is for the NSR permit to contain a provision prohibiting the CO_2 BACT limitation from exceeding the CO_2 emissions that are allowable under one of the following potentially applicable NSPS limitations for new combustion turbines:

- The 2024 Subpart TTTTa limitations, which establishes CO_2 performance standards and currently applies to new combustion turbines;

- The prior 2015 Subpart TTTT limitations, which applied to new combustion turbines prior to the adoption of the more stringent 2024 performance standards and could apply again if EPA were to repeal the 2024 NSPS limitations and revert to the prior 2015 NSPS limitations; or

- Any new applicable CO_2 NSPS limitations that EPA may adopt pursuant to this or a future rulemaking.

In support of this alternative approach, EPA could refer to its 1979 guidance that allowed for the establishment of multiple provisional BACT limitations for sulfur dioxide (SO_2) due to a similar uncertainty on the level of a future SO_2 NSPS that would apply prospectively.[63] In effect, this approach allows the establishment of only one CO_2 BACT limitation that contains cross references to any potentially applicable NSPS limitations to assure compliance with the CO_2 BACT standard-setting process.

[63] *See* Memorandum from W.C. Barber, Director, EPA Office of Air Quality Planning and Standards, *BACT Determinations for Power Plants Subject to Revised NSPS* (Jan. 10, 1979).

B. EPA Should Issue National Guidance Clarifying That the 2024 NSPS Limitations Do Not Apply to All New Combustion Turbine Projects.

The second regulatory challenge is an implementation problem that results from current NSPS regulations for determining the applicability of newly adopted NSPS limitations. Those regulations could be interpreted to require that the current, overly stringent 2024 Subpart TTTTa limitations should apply to those turbine projects for which binding contracts have been executed for the fabrication and purchase of new combustion turbines. Given that many electric utilities have recently and are currently entering into such binding contracts for combustion turbines due to the need to build additional new dispatchable combustion turbine generation, those utilities may remain subject to the current, more stringent standards under the current NSPS applicability rules even if EPA repeals or lowers the stringency of those performance standards to achievable control levels pursuant to this rulemaking.

Current Rules for Determining NSPS Applicability. The current EPA regulations generally require that the newly adopted CO_2 performance standards (with CO_2 limitations) would only apply to those affected combustion turbine projects that "commenced construction" after the date that EPA issues the upcoming proposed rule (which would occur this fall at the earliest). Under those EPA regulations, the term "commence construction" is not limited to onsite construction but also includes those projects where the owner or operator of that new affected source executes binding contracts with substantial liquidated damages for cancellation. This means that all new combustion turbines that commenced construction on or prior to the date of the upcoming proposed rule will be subject to the current, more-stringent, NSPS Subpart TTTTa limitations that impose the CCS and the overly stringent efficiency standards noted above. Given that many electric utilities have already executed binding contracts with liquidated damages for the fabrication and purchase of new combustion turbines, these utilities may be subject to those stringent Subpart TTTTa standards and thereby not get the benefit of the relief provided by new upcoming CO_2 performance standards.

Proposed Solution. EPA must take measures to ensure that the current, overly stringent, CO_2 NSPS limitations do not apply to those turbine projects for which binding contracts have been executed for the fabrication and purchase of new combustion turbines. The solution to this problem will most likely require either rulemaking action or Agency guidance clarifying how the NSPS applicability rules will apply to new combustion

turbines for which electric utilities have executed binding turbine contracts prior to EPA's issuance of the revised CO_2 performance standards for new combustion turbines.

VIII. AMP Supports Comments Submitted by the American Public Power Association, the Large Public Power Council, the Alliance for Fuel Options, Reliability, and Diversity, and Prairie State Generating Company, LLC.

AMP is a member of the American Public Power Association ("APPA"), the Large Public Power Council ("LPPC"), the Alliance for Fuel Options, Reliability, and Diversity (AFFORD), and an owner of the Prairie State Generating Company, LLC. AMP supports many of the comments submitted by these entities.[64] In particular, AMP supports APPA's and LPPC's technical evaluation of the Phase I standards applied to gas turbines that demonstrate those standards are neither reasonable nor achievable in practice during real-world operations.

Respectfully submitted,

Adam Ward
Senior Vice President of Member Services,
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[64] AMP's comments may differ on some issues from the APPA, LPPC, AFFORD, and Prairie State comments. To the extent the positions and recommendations in AMP's comments differ from those expressed in the comments of APPA, LPPC, or Prairie State, the positions expressed herein should be viewed as controlling.