COMMENTS OF THE CLASS OF '85 REGULATORY RESPONSE GROUP

ON

EPA'S PROPOSAL ON 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

EPA Docket No. EPA-HQ-OAR-2023-0072

August 8, 2023

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I. INTRODUCTION

On May 23, 2023, EPA published in the *Federal Register* its proposal on five separate actions under Section 111 of the Clean Air Act ("CAA") to regulate greenhouse gas ("GHG") emissions from fossil fuel-fired electric generating units ("EGUs"), which encompasses steam generating units, integrated gasification combined cycle units ("IGCCs"), and stationary combustion turbines ("Proposal").[1] Specifically, EPA is proposing to revise 40 C.F.R. Part 60 as follows: (1) revise the new source performance standards ("NSPS") under Section 111(b) of the CAA for GHG emissions from new fossil fuel-fired stationary combustion turbines (proposed Subpart TTTTa); (2) revise the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification (proposed Subpart TTTTa); (3) establish emission guidelines pursuant to CAA Section 111(d) for GHG emissions from existing fossil fuel-fired steam generating EGUs (proposed Subpart UUUUb); (4) establish emission guidelines pursuant to CAA Section 111(d) for GHG emissions from the largest, most frequently operated gas-fired stationary combustion turbines (proposed Subpart UUUUb); and (5) repeal the Affordable Clean Energy Rule (Subpart UUUUa).

The Class of '85 Regulatory Response Group ("Class of '85" or "Group") respectfully submits these comments on the Proposal.[2] The Class of '85 is a voluntary, ad hoc coalition of over 40 electric generating companies from across the country that has been actively involved in the development and implementation of CAA rules affecting the electric generating industry for over 35 years, including the regulation of GHG emissions from new and existing EGUs. Members of the Group own and operate existing EGUs throughout the United States and either have or may develop plans to construct and operate new EGUs in the future, or modify existing units. Accordingly, they will be directly and significantly impacted by final regulations issued pursuant to Sections 111(b) and (d) of the CAA. The Section 111(b) and (d) regulations also will impact how Group members fulfill their responsibilities to their individual customers and the general public to ensure that electricity remains affordable to households and businesses across the United States and that the reliability standards approved by the Federal Energy Regulatory Commission ("FERC") and by state public utility commissions are met. This includes supporting the rapidly growing demand for electricity as various sectors, including the automobile industry, shift to electrification, and as cleaner sources of generation become more predominant.

II. SUMMARY OF COMMENTS

Notwithstanding the comments provided herein, the Class of '85 emphasizes that its member companies support and are taking actions to reduce GHG emissions to enable the transition to a low-carbon economy. Relatedly, the Group views both carbon capture and storage/sequestration ("CCS") and low-GHG hydrogen co-firing—two technologies proposed as the best system of emission reduction ("BSER") for certain EGU subcategories—as important technologies that, once fully mature and available (including all the necessary attendant

[1] 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, 88 Fed. Reg. 33,240 (May 23, 2023).

[2] A list of the Class of '85 members supporting these comments is included in Attachment A.

infrastructure), will be key to reducing carbon dioxide ("CO_2") emissions from dispatchable generation resources and achieving net zero carbon emissions from the EGU sector.

However, EPA's Proposal must be mindful of the complexities of the electricity sector to successfully achieve the proposed GHG emission reductions. Aside from company-specific circumstances, the pace and timing of EPA's final standards for EGUs under both CAA Section 111(b) and Section 111(d) must recognize other influences that could impact the economics of these standards, including the expiration of credits and other funding from the Inflation Reduction Act ("IRA"), availability of labor and equipment, and regional variations (such as wind and solar availability) affecting the need for natural gas generation to support intermittent renewable energy resources.

Furthermore, the Group is concerned that the Proposal has legal and technical deficiencies. Among other areas of concern, the Group does not agree with EPA that CCS and low-GHG hydrogen co-firing, as these technologies currently stand, have been adequately demonstrated as BSER for Phases 2 and 3 for various proposed EGU subcategories. The Group believes that these technologies and their associated infrastructure and actions necessary to support these technologies, such as permitting and land acquisition, will not be widely available and in place throughout the United States by the proposed compliance deadlines; relatedly, these technologies may not be feasible in certain regions due to geographic differences.

Specifically concerning low-GHG hydrogen, the Group believes that the proposed requirements concerning the manner in which hydrogen fuel is created are outside the scope of Section 111(d) as it applies to the electric generating sector. Further, since producers of hydrogen may commingle hydrogen produced from a variety of processes, there is no way to physically distinguish how hydrogen was made. Questions regarding the method of production must be directed at fuel producers rather than fuel consumers. Although EGU owners/operators may be required to test the fuels' physical and chemical characteristics, that is a far cry from asking them to determine the pedigree of their fuels. In sum, EPA's Proposal to establish CCS and low-GHG hydrogen co-firing as BSER is premature at best.

The Group also is concerned that EPA is not providing sufficient guidance to states on their authority with respect to the development of their state plans. For example, EPA needs to provide more guidance to states on the development of source-specific emission standards for units that do not fit neatly into a subcategory, such as coal-fired steam generating units that may not be retiring but will cease using coal between the 2030 and 2040 timeframe, including those planning to repower to the use of other fuels.

Additionally, the Group is concerned that EPA's Proposal to regulate existing large, frequently operated gas-fired stationary combustion turbines is not well-defined. Coupled with the additional memoranda and modeling results that EPA recently added to the rulemaking docket, which appear, in part, to modify the Proposal, EPA should thoroughly consider the ambiguities and consequences resulting from issuance of a proposed rule in pieces that appear to be contradictory with respect to regulating GHG emissions from stationary combustion turbines.

The Group urges EPA to promote clarity and more fully develop and reissue its proposed regulation of GHG emissions from stationary combustion turbines instead of attempting to rely on

additional addenda submitted to the docket during the comment period, or other unofficial means to clarify ambiguities in the Proposal. The issues addressed in the memoranda that were recently added to the rulemaking docket are more than mere clarifications to EPA's proposed regulation of large and frequently operated stationary combustion turbines. Instead, they are critical policy design considerations impacting the feasibility and costs of compliance for stationary combustion turbines. EPA's fragmented rulemaking also creates unnecessary planning uncertainty for state agencies and other regulatory agencies that must ensure reliable and safe electricity production. This uncertainty could stall current efforts by electric generating companies that are underway to voluntarily reduce GHG emissions and support broader economywide decarbonization through electrification. Given these concerns, the Group urges EPA to carefully gauge the effects that this rulemaking will have on grid reliability, affordability, and future growth, and reissue a proposed rule with respect to regulating GHG emissions from stationary combustion turbines that incorporates all necessary components of the rule.

III. OPPORTUNITY FOR PUBLIC COMMENT

EPA must extend the comment period to satisfy the Administrative Procedure Act ("APA") requirements. Although EPA granted a 15-day extension of the original comment deadline,[3] it is not adequate to allow companies with potentially affected EGUs to fully analyze the impacts of the Proposal and submit comprehensive comments to EPA.[4] The APA's notice and comment requirements are intended to (1) ensure that agency regulations are tested via exposure to diverse public comment, (2) ensure fairness to affected parties, and (3) give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review.[5] When a significant number of commenters have requested an extension, that further supports later findings that a rule is deficient under the APA because it deprived the public of the opportunity to provide informed comments.[6]

Another indication that the public has been deprived of the opportunity to provide informed comments is the fact that EPA initially declined to proceed with a full panel review in determining whether the Proposal would have a significant impact on small businesses. During the Small Business Review *Pre*-Panel discussion to determine the proposed rule's significant impact, EPA only asked the panel members about reporting burdens—a significantly minor concern compared to the range of issues covered in this Proposal. While the Class of '85 appreciates that EPA recently switched course and decided to move forward with a full panel review, this further warrants extending the comment period by more than 15 days so that members of the review panel have sufficient time to provide additional feedback.

In this instance, EPA should extend the comment period by another 60 days given the profound impacts the Proposal has on the electric generating industry.[7] More time is needed for

[3] 88 Fed. Reg. 39,390 (June 16, 2023).

[4] *See, e.g.*, *California v. U.S. Dep't of the Interior*, 381 F. Supp. 3d 1153, 1172 (N.D. Cal. 2019).

[5] *Prometheus Radio Project v. FCC*, 652 431, 449 (3d Cir. 2011).

[6] *See, e.g.*, *Centro Legal de la Raza v. Exec. Off. for Immigr. Rev.*, 524 F. Supp. 3d 919, 955 (N.D. Cal. 2021); *California v. U.S. Dep't of the Interior*, 381 F. Supp. 3d 1153.

[7] *See* Class of '85 Regulatory Response Group's Second Request for an Extension of the Comment Period on EPA's Clean Air Act Section 111 Proposal, Dkt ID No. EPA-HQ-OAR-2023-0072-0195 (posted July 26, 2023).

companies, states, regional transmission organizations ("RTOs"), regional reliability authorities, and independent system operators ("ISOs") to adequately evaluate the cost and feasibility of the Proposal.

The Proposal alone, without the proposed regulatory text, is 181 pages long in the *Federal Register*, along with 62 supporting documents (as of July 2, 2023) available in the docket that are highly technical in nature, with other documents added after that date, including two new documents relating to the proposed regulation of stationary combustion turbines. As further discussed *infra* Section IV.C.3, approximately three weeks after publishing the Proposal in the *Federal Register*, EPA issued a memorandum on its website,[8] "Applicability of Emission Guidelines to Existing Stationary Turbines: FAQs Memo to the Docket" (June 12, 2023) ("FAQs Memo"), containing new information that significantly deviates from the proposed regulatory text available in the docket and the published preamble. The FAQs Memo was not even added to the rulemaking docket until July 7, 2023.[9] On the same day, EPA posted another memorandum to the rulemaking docket, the "Additional Modeling Memo," along with 22 attachments and four new IPM model run outputs, to supplement the record.[10]

The Proposal is complicated and encompasses two proposed new substantive rules: (1) Subpart TTTTa to address NSPS for stationary combustion turbines and significant modifications to steam electric generating units; and (2) Subpart UUUUb to address emission guidelines for existing EGUs. EPA is seeking comment on several aspects of both proposed rules. Yet, by providing inadequate time to analyze those aspects, it appears that the Agency is rushing through the comment period in lieu of seeking thoughtful responses to its requests for comments. When rules are considered "significant regulatory action" the time allotted for comments should reflect this.[11] There is no consent decree, statutory deadline, or other similar driver to justify the compressed schedule for affected entities to review the Proposal and provide comments.

The Proposal also is one of several key rulemakings affecting Group members that EPA is simultaneously undertaking and, given the back-to-back comment deadlines, it is difficult to respond meaningfully to each of these rulemakings and fully evaluate the potential impacts on electric generating unit operations. The other Agency proposals affecting the electric generating industry that have overlapped on review and preparation of comments by Class of '85 members include: (1) the proposed rule on Supplemental Effluent Limitations Guidelines ("ELG") and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18,824 (Mar. 29, 2023) (comments submitted May 30, 2023); (2) the proposed rule amending the National Emissions Standards for Hazardous Air Pollutants for the Coal- and Oil-fired Electric Utility Steam EGUs (commonly referred to as "MATS"), 88 Fed. Reg. 24,854 (Apr. 24, 2023) (comments submitted June 23, 2023); and (3) the proposed rule on the Hazardous Solid Waste Management

[8] https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

[9] Dkt ID No. EPA-HQ-OAR-2023-0072-0143.

[10] *See* EPA, *Integrated Proposal Modeling and Updated Baseline Analysis* (July 7, 2023) ("Additional Modeling Memo"), Dkt ID No. EPA-HQ-OAR-2023-0072-0237, https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf.

[11] *Centro Legal de la Raza*, 524 F. Supp. 3d at 955.

System: Disposal of Coal Combustion Residuals ("CCR") from Electric Utilities; Legacy CCR Surface Impoundments, 88 Fed. Reg. 31,982 (May 18, 2023) (comments submitted July 17, 2023).

These rulemakings, both individually and collectively, have wide-ranging implications for EGUs across the country, including those owned and/or operated by Group members, and they each have hundreds of supporting documents that are highly technical in nature. The Group strongly recommends that EPA harmonize the recent suite of rulemakings aimed at EGUs. The Group needs to be able to holistically analyze these proposed rulemakings and others that EPA may be contemplating, such as whether to regulate smaller and less frequently operated existing stationary combustion turbines—particularly as to how all of these rules' requirements impact existing EGUs' short- and long-term operating plans, how electric generating companies should structure replacement generation, and how the rules may impact the reliability and affordability of electricity.

With respect to the Proposal, Class of '85 members need to undertake thorough analyses as to what options are available and feasible to achieve compliance with the proposed standards, requiring significant staff support as well as the retention of consultants to conduct such analyses. Accordingly, given that members of the Class of '85 have only recently been able to fully focus on the Proposal, more time is required to provide accurate and meaningful feedback to EPA, as well as respond to the specific questions posed by the Agency.

IV. LEGAL COMMENTS

A. CCS and Low-GHG Hydrogen Co-Firing Do Not Qualify as BSER

In the Proposal, EPA identifies CCS and co-firing of low-GHG hydrogen as BSER for various EGU subcategories.[12] EPA has proposed CCS and low-GHG hydrogen co-firing because: (1) "a range of cost-effective technologies and approaches to reduce GHG emissions from [fossil fuel-fired EGUs] are available to the power sector"; (2) "multiple projects are in various stages of operation and development—including carbon capture and sequestration/storage (CCS) and co-firing with lower-GHG fuels"; and (3) "Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to achieve reductions in GHG emissions from the power sector."[13] However, these technologies—which, for CCS, encompass carbon capture, compression, transportation pipeline networks, and large-scale permanent sequestration; and which, for low-GHG hydrogen, encompass scalability, transportation pipeline networks, and storage systems—have not been adequately demonstrated.

To start, the fact that Congress has provided incentives to develop the technologies should have no bearing on EPA's cost-effectiveness evaluation, as there is no guarantee that the incentives will continue to be available, let alone result in the technologies being commercially available by the timeframe EPA proposes, or that a source will meet the eligibility requirements imposed by the applicable federal agency. In fact, congressional incentive funding demonstrates the contrary. Historically, Congressional allocations do not match actual funding. For example, in the Energy Policy Act of 2005, Congress allocated $3.275 billion for the development of hydrogen fueling

[12] *See, e.g.*, 88 Fed. Reg. at 33,243.

[13] *See id.* at 33,242–43.

infrastructure.[14] However, only $1.48 billion in actual funding materialized from 2006 to 2010; and while funding continued through 2019, no vast infrastructure was developed in the nearly two-decades long funding timeframe.[15] Accordingly, the $9.5 billion allocated for the four regional clean hydrogen hubs pursuant to the IRA likely will be significantly less in actual funding. In addition, the IRA funding is limited to a 10-year period and the credits are available only until the four-year phase-out is triggered in the later of 2032 or the year that power-sector emissions are 25 percent of 2022 levels. CCS and hydrogen co-firing projects likely would not be cost-effective once the credits cease.

Moreover, the fact that Congress provided incentives in the IRA to develop CCS and hydrogen co-firing is itself evidence of the still-nascent state of the technologies' commercial availability and the related infrastructure's deployment (such as production, transportation, and storage). Thus, the IRA's incentives do not support a determination that either of the technologies has been "adequately demonstrated." While these technologies demonstrate potential and the power sector is working toward their deployment, they simply are not adequately demonstrated at this time nor is it likely they will be by the proposed compliance deadlines.

The information on which EPA has relied for identifying CCS and low-GHG hydrogen co-firing as BSER primarily rests on demonstration projects, vendors' forecasts for availability of certain technologies which are not guaranteed, and the *assumption* that such technologies will be "adequately demonstrated" by the compliance deadlines set forth in the Proposal. For example, although the Proposal states that "some turbines are available now that can combust 100 percent hydrogen in the future and there is significant evidence that such turbines will be more widely available by the 2030s," the only support for this statement that EPA offers is a 2022 article, "Siemens Energy Explores Gas Turbines' Future in Net-Zero Energy Mix," and is limited to an unofficial statement made by a member of Siemens Energy's executive board.[16] The other articles on which EPA relies to support low-GHG hydrogen co-firing as BSER are similarly unconfirmed.[17] One describes how a vendor "aims to achieve 100% hydrogen,"[18] and another notes that a vendor "has set an *ambitious target* to have all its new gas turbines capable of burning 100% hydrogen on or before the end of 2030."[19] EPA's citations show that it relied on the

[14] *See* Pub. L. No. 109-58, tit. VIII, 119 Stat. 594, 844–55 (2005).

[15] *See* U.S. Dep't of Energy, *Budget* (last visited Aug. 1, 2023), https://www.hydrogen.energy.gov/budget.html; *see also* Alan C. Lloyd & Robert S. Walker, Hydrogen and Fuel Cell Technical Advisory Committee, *Hydrogen and Fuel Cell Technical Advisory Committee Biennial Report to the Secretary of Energy* 3 (2007) ("Funding for the hydrogen program should be increased at least to the $3.275 Billion authorized by [the Energy Policy Act of 2005.]").

[16] 88 Fed. Reg. at 33,308; *see also* Roberta Prandi, *Siemens Energy Explores Gas Turbines' Future in Net-Zero Energy Mix*, Diesel & Gas Turbine Worldwide (Nov. 18, 2022) (including significant discussion on the use of biodiesel, cracked ammonia, methanol, hydrogenated vegetable oils and Fatty Acid Methyl Esters for co-firing, which EPA eschews in its Proposal), https://www.dieselgasturbine.com/news/siemens-energy-explores-gas-turbines-future-in-net-zero-energy-mix/8024799.article.

[17] *See* 88 Fed. Reg. at 33,308 nn. 407, 409 (citing sources *infra* footnotes 18 and 19).

[18] Kevin Lark, *Mitsubishi Highlights Four Hydrogen Projects at CERAWeek*, Power Engineering (Mar. 8, 2022), https://www.power-eng.com/hydrogen/mitsubishi-power-highlights-four-hydrogen-projects.

[19] Siemens Energy, *Siemens Energy to Provide Hydrogen-Capable Turbines to Back Up Utility-Scale Solar Installation in Nebraska* (June 17, 2021) (emphasis added), https://press.siemens-energy.com/global/en/pressrelease/siemens-energy-provide-hydrogen-capable-turbines-back-utility-scale-solar-installation.

"ambitious targets" and "aims" of vendors published in aspirational marketing and public relations materials. These are not sufficient indications of a system of emission reduction that is "adequately demonstrated" for the purposes of establishing BSER.

EPA would exceed its statutory authority by establishing technology-based standards of performance that do not meet the statutory requirement in CAA Section 111(a)(1) of being "adequately demonstrated."[20] EPA should not determine that a control has been "adequately demonstrated" where the control is new and not yet in widespread commercial use. Further, EPA should not speculate as to the timeframe for the development of a control and then establish requirements that take effect at that future time.[21] Citing *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973), EPA acknowledges that, while BSER need not mean actual routine use, any projection based on existing technology must be "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry."[22] In fact, *Portland Cement* further states that the validity of EPA's projection rests on the reliability of the prediction and the nature of the assumption, and that "the question of availability is partially dependent on 'lead time', the time in which the technology will have to be available."[23]

Notwithstanding the language in CAA Section 111(a)(1), EPA is projecting when CCS and low-GHG hydrogen co-firing and the related actions/infrastructure to support those technologies will be widely available for installation, with little record to support such projections—and even less legal authority to justify such a scant record. EPA's unsupported assumptions include when production of low-GHG hydrogen will be at scale for safe use in stationary combustion turbines, when networks of pipelines needed to support the technologies will have safety concerns satisfied and will be permitted and constructed, and when permitting for geologic fields for CO_2 sequestration will be in place and safety is no longer a concern, among several other assumptions. All of these assumptions are further complicated by the fact that EPA fails to present any "big picture" on how CCS and low-GHG hydrogen connect/interact with electric generators' existing (and future) transmission distribution systems. And, to the extent there are no studies on these technologies' interaction with the grid, considerable time is needed to identify if such integration would be feasible in the first place. Predicting the confluence of all of these activities includes a combination of projections, assumptions, and optimism, which would be far too speculative to satisfy a reasonable projection under *Portland Cement*. In fact, the court in *Portland Cement* remanded the Agency's projections because it could "not identify the location[, details,] or methodology used in the one successful test."[24] In the Proposal, EPA is making *multiple* projections that lack a coherent methodology or details to support its projections.

Further, the issue in *Portland Cement* was not whether the technology actually existed and was available to facilities, which it was, but rather whether that technology, if implemented, would be able to achieve the standards and whether EPA's cost analysis was accurate.[25] The concerns

[20] 42 U.S.C. § 7411(a)(1); *see also* 42 U.S.C. § 7411(d).

[21] *See* 88 Fed. Reg. at 33,244.

[22] *See id.* at 33,272.

[23] *Portland Cement*, 486 F.2d at 391–92.

[24] *Id.* at 392.

[25] *See id.* at 387.

that underlie the Proposal are more fundamental because here, unlike in *Portland Cement*, EPA has not even shown that the technology is available in the first place.

The Proposal is distinguishable from prior rulemakings where EPA "provided the regulated sector with lead time to accommodate the availability of technology."[26] Lead times for prior rulemakings were based on the time needed to install demonstrated controls (for example, for manufacturers to ramp up production and competition for the services of a finite number of vendors); not projections of when non-demonstrated controls and required infrastructure would appear.[27] Additionally, those lead times were significantly shorter (*e.g.*, two years) than for CCS and low-GHG hydrogen co-firing. The Agency cites to the implementation of flue gas desulfurization ("FGD") to address SO_2 emissions subsequent to the 1971 NSPS for electric generating units for the proposition that "companies with the expertise to install complex emission control equipment can rapidly ramp up capacity in response to a regulatory driver."[28] However, what EPA fails to consider is that FGD was already demonstrated at several EGUs, specifically among EGUs that had implemented or contracted for SO_2 removal systems at the time of the rule.[29] Further, FGD does not require complex and significant support infrastructure, such as pipelines and access to geologic fields and associated permitting and land acquisition issues, which makes CCS and low-GHG hydrogen co-firing incomparable to installation of FGD technology.

In addition, CCS and low-GHG hydrogen co-firing require significant retrofit modifications that may not be possible at some existing units. EPA also fails to consider the effects of state and local codes and standards, which may cause delays and additional roadblocks for implementation of CCS and low-GHG hydrogen co-firing, particularly with respect to the attendant infrastructure required. Hydrogen specifically comes with inherent safety risks during transportation, storage, and combustion, which would be regulated by other federal requirements, as well as state and local fire codes and standards.[30] It is possible that states and localities will resist operation of hydrogen pipelines in their areas due to safety concerns, as demonstrated by the recent opposition to two pipelines in the mid-Atlantic region. And, EPA has failed to address how its proposed BSER of low-GHG hydrogen co-firing and CCS *and* their attendant infrastructure needs fit within the Supreme Court's decision in *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), regarding the limits of EPA's CAA authority.

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[26] 88 Fed. Reg. at 33,289.

[27] *See, e.g.*, 81 Fed. Reg. 59,221 (Aug. 29, 2016) (Municipal Solid Waste Landfills); 78 Fed. Reg. 58,415 (Sep. 23, 2013) (Storage Vessels (Crude Oil and Natural Gas Production, Transmission and Distribution)); 77 Fed. Reg. 49,489 (Aug. 16, 2012) (Petroleum Refineries).

[28] 88 Fed. Reg. at 33,367.

[29] Sixteen EGUs implemented or were implementing limestone scrubbing; one had implemented or was implementing sodium hydroxide scrubbing installations; two had implemented or were implementing magnesium oxide scrubbing installations; and one had implemented or was implementing catalytic oxidation. *See* 37 Fed. Reg. 5,768 (Mar. 23, 1972).

[30] *See e.g.*, 88 Fed. Reg. at 33,308 n. 410 (citing L.A. Dep't of Water & Power, *Scattergood Modernization Project: Responses to Questions from Energy & Environmental Committee*, at 10 (Feb. 3, 2023), https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf. *See generally* National Fire Protection Association, Model Hydrogen Technologies Code (2023) (discussing safeguards on the generation, installation, storage, piping, use, and handling of hydrogen in compressed gas form or cryogenic liquid form), https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=2.

EPA cannot rely on a multi-phase BSER to circumvent the statutory requirement that BSER be "adequately demonstrated." Forcing the implementation and regulation of undemonstrated technology that is still in the developmental stage on the electric generating industry is not necessary as the CAA specifically requires EPA, for the NSPS, to "*at least* every 8 years, review and, if appropriate, revise" the standards.[31] Thus, rather than trying to predict the future by establishing standards based on inadequately demonstrated GHG emission reduction technologies for which EPA has to predict future availability, the Agency should reevaluate the technologies that are in fact "adequately demonstrated" to establish as BSER, and modify the proposed standards to reflect this so that they can be implemented on a broad industry-wide basis regardless of company-specific circumstances or location.

Lastly, EPA needs to clarify in any final regulations that these are emissions standards and not technology mandates. Based on the proposed regulatory text, sources must meet the standards based on the subcategory into which they are slotted. Installation of BSER is not directly addressed in the proposed regulatory text for each applicable standard although, for the Section 111(d) standards, the increments of progress that EPA proposes identify milestones associated with the installation of the technologies determined to be BSER. EPA must make it explicitly clear for both Subparts TTTTa and UUUUb that sources are *not* required to install and operate the technology that EPA determined is BSER if they can otherwise meet the standard and that, for Subpart UUUUb, states have the authority to tailor the increments of progress according to how compliance with the standard will be achieved (*see* discussion in Section V.H, *infra*, concerning compliance milestones and the need for compliance flexibility). It is important for EPA to address this directly because the technologies on which standards are based may not be the ones deployed based on company-specific circumstances.

B. EPA Must Publish the Proposed Regulatory Text in the *Federal Register*

EPA failed to publish the proposed regulatory text for Subparts TTTT, TTTTa, and UUUUb in the *Federal Register* notice for the Proposal, and it is essential in this instance that EPA do so because consequences flow from the date of publication of the proposed NSPS in Subpart TTTTa. Only in one passing reference did the Agency note the availability of the proposed regulatory text.[32] In fact, EPA appears to have adopted the practice of not publishing the proposed regulatory text in the *Federal Register* more frequently in recent rulemakings, including the proposed rule to amend MATS.[33] For the following reasons, the Class of '85 strongly urges the Agency not to continue this practice. EPA must publish the proposed regulatory text in the *Federal Register*, especially in this rulemaking.

First, under CAA Section 111(a)(2), a source is considered a "new source" subject to the proposed NSPS if its construction or modification "is commenced after the *publication* of *regulations* (or, if earlier, *proposed regulations*)" prescribing the proposed NSPS.[34] Placing a

[31] 42 U.S.C. § 7411(b)(1)(B) (emphasis added).

[32] *See* 88 Fed. Reg. at 33,334 (describing the text as "the redline strikeout version of the rule showing the proposed amendments").

[33] 88 Fed. Reg. 24,854 (Apr. 24, 2023).

[34] 42 U.S.C. § 7411(a)(2) (emphases added).

redline strikeout of the proposed regulation in the docket does not appear to meet the definition of "publication" as Congress used it in the CAA.

EPA has offered no legal authority for its interpretation that merely publishing a description of the proposed NSPS is sufficient to force sources that commence construction after the date of publication of the description (here May 23, 2023) to meet the new standards.[35] And the text of the CAA contradicts EPA's position, as the statute explicitly identifies *publication* of the proposed regulation. Merely including the proposed regulatory text in the docket cannot mean "publication," as that would mean that all supporting documents, which are also included in the docket, would be considered "published" as well. Likewise, describing the proposed standards in the *Federal Register* notice is not equivalent to publishing the "proposed regulation." The final description has no legal force or effect upon publication in the *Federal Register*; only the final regulations do. Therefore, publishing a description of the proposed NSPS in the *Federal Register* cannot trigger the commencement of construction requirement for new sources pursuant to CAA Section 111(a)(2).

Second, by posting the proposed regulatory text for Subparts TTTTa and UUUUb as a separate document, EPA runs the risk of creating discrepancies between the description of the proposed text in the *Federal Register* and the proposed regulatory text available in the docket. Such discrepancies prevent EGUs and other stakeholders, including members of the general public who may not have sufficient familiarity with online dockets, from receiving adequate notice of EPA's proposed action, thus impairing their ability to provide informed comments. EPA also runs the risk of running afoul of its statutory duty under the APA to provide the public with adequate notice, particularly if the description of the proposed text in the *Federal Register* notice fails to accurately capture "either the terms or substance of the proposed rule or description of the subjects and issues involved."[36] That is clearly the case here, as evidenced by EPA's issuance of the FAQs Memo to address the applicability of Subpart UUUUb to existing stationary combustion turbines relating to issues that the Agency had failed to address in the Proposal. EPA's "clarifications" in the FAQs Memo need to be squarely addressed in the Proposal rather than just in an online document that is not published as part of the Proposal. If EPA fails to publish the proposed Subpart TTTTa regulations in the *Federal Register*, based on the clear statutory language, stationary combustion turbines that commence construction between May 23, 2023, and the date of publication of the final Subpart TTTTa regulations in the *Federal Register* would not be considered new sources to which the Subpart TTTTa standards are applicable. Instead, they would remain subject to the Subpart TTTT standards promulgated in 2015.

Third, the deadline for submitting comments should not be triggered until EPA has included the proposed regulatory text in the *Federal Register*. To ensure that the public is afforded a meaningful opportunity to comment on proposed rules, the 60-day comment period should not

[35] That EPA interprets the CAA thus is apparent from the Proposal: "The proposed NSPS, proposed to be codified in 40 CFR part 60, subpart TTTTa, once promulgated, will be directly applicable to affected facilities that begin construction or reconstruction after the date of publication of the proposed standards in the **Federal Register**." *See also* proposed 40 C.F.R. § 60.5508a.

[36] 5 U.S.C. § 553(b).

run until the public has received fair and adequate notice of the regulatory language itself—not merely a passing reference in the Proposal to the availability of the text in the docket.

C. Stationary Combustion Turbines Constructed After January 9, 2014 Are Already Subject to the NSPS and Cannot Be Subject to the Section 111(d) Standards

Stationary combustion turbines constructed between January 9, 2014, and the date the regulatory language for Subpart TTTTa is published in the *Federal Register* are subject to the Subpart TTTT GHG standards.[37] Based on the language of the CAA and the Proposal, they cannot also be subject to the GHG emission guidelines promulgated pursuant to CAA Section 111(d) for existing sources.

1. The statute is clear that a new source cannot also be considered an existing source

The CAA establishes two avenues for applying Section 111 standards of performance to sources: (1) regulation of "new sources" under Section 111(b); or (2) regulation of "existing sources" under Section 111(d). These two avenues are mutually exclusive. A source cannot be both a new source and an existing source. Under Section 111(a)(6), "[t]he term 'existing source' means any stationary source other than a new source." In contrast, Section 111(a)(2) defines a "new source" as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) *prescribing a standard of performance under this section [that] will be applicable to such source*."[38] In light of this clear statutory language, EPA cannot interpret Section 111(d) to apply to stationary combustion turbines that already became subject to a NSPS as a new source for the same pollutant.

2. The Proposal and proposed regulatory text make clear that EPA did not intend stationary combustion turbines subject to Subpart TTTT to be considered existing sources for Section 111(d) purposes

According to the proposed regulatory text, the proposed emission guidelines would apply only to an "affected EGU," and state plans must address (1) EGUs that were in operation or had commenced construction on or before January 8, 2014; (2) natural gas fired stationary combustion turbines that commenced construction or reconstruction before May 23, 2023 (the date of publication in the *Federal Register*); or (3) coal-fired steam generating units that commenced modification before May 23, 2023 (the date of publication in the *Federal Register*).[39] However, that provision goes on to state that such EGUs are considered affected units *unless* they meet one of the exclusions provided in § 60.5850b.[40] In turn, EGUs that are expressly excluded from being an "affected EGU" include, as provided in proposed § 60.5850b(b), new or reconstructed EGUs

[37] As discussed *supra* Section IV.B, the date of publication of the Proposal of May 23, 2023, cannot be considered the date of applicability for Subpart TTTTa because the proposed regulation itself was not *published* in the *Federal Register*.

[38] 42 U.S.C. § 7411(a)(2) (emphasis added).

[39] *See* proposed § 60.5845b(a).

[40] *See* proposed § 60.5845b(b).

that are subject to 40 C.F.R. Part 60 Subpart TTTT as a result of commencing construction after the Subpart TTTT applicability date (January 8, 2014, for new EGUs and June 18, 2014, for reconstructed EGUs). Accordingly, EGUs that are already subject to Subpart TTTT are excluded from also being subject to the proposed Subpart UUUUb standards.

The Proposal confirms this conclusion. In the Proposal, EPA explicitly states that:

> Section 111(a)(6) of the CAA defines an "existing source" as "any stationary source other than a new source." Therefore, the emission guidelines would not apply to any EGUs that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT.[41]

Proposed Subpart UUUUb expressly considers stationary combustion turbines to be EGUs. According to proposed § 60.5508a, "[a]n affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU)."[42]

Thus, according to the Proposal and the proposed regulatory text, stationary combustion turbines that are already subject to Subpart TTTT are excluded from also being subject to the emission guidelines pursuant to Section 111(d). The Group agrees with EPA's conclusion in both the Proposal and the proposed regulatory text that the emission guidelines in Subpart UUUUb do not apply to EGUs, including stationary combustion turbines, that are already subject to Subpart TTTT.

3. EPA's position in the FAQs Memo contradicts the clear statutory language of the CAA and EPA's position in the Proposal

About three weeks after the Proposal was published in the *Federal Register*, EPA issued its FAQs Memo, which contradicts its statement in the Proposal and the proposed regulatory text and instead claims that stationary combustion turbines that are new after January 8, 2014, or reconstructed after June 18, 2014, are in fact subject to the emission guidelines.[43] The first question that EPA's FAQs Memo addresses is: "Based on construction or reconstruction date, which stationary combustion turbines are existing sources that may be subject to UUUUb?" According to the FAQs Memo:

> Stationary combustion turbines that commenced construction or reconstruction before May 23, 2023, are existing sources that may be affected EGUs under proposed UUUUb, as provided for in the proposed provision at 40 C.F.R. § 60.5845(b)(a)(2): . . . The EGUs that must be addressed by your plan are . . .

[41] 88 Fed. Reg. at 33,342.

[42] This is consistent with the definition of electric generating unit in Subpart TTTT, which is also applicable to proposed Subpart UUUUb: "any steam generating unit, IGCC unit, or *stationary combustion turbine* that is subject to this rule (*i.e.*, meets the applicability criteria)." 40 C.F.R. § 60.5580 (emphasis added).

[43] As discussed *supra* Section III, EPA made the FAQs Memo available on its website on June 12, 2023, but did not issue any announcements or statements regarding the issuance of the FAQs Memo, and it was not even posted to the rulemaking docket until July 7, 2023 (Dkt ID No. EPA-HQ-OAR-2023-0072-0143).

> [n]atural gas fired stationary combustion turbines that commenced construction or reconstruction before May 23, 2023.

The FAQs Memo claims that "[t]here are no exclusions under proposed UUUUb that are based on construction or reconstruction date and that are specific to stationary combustion turbines."[44] EPA asserts without any justification that the term "EGUs" in the proposed exclusions at 40 C.F.R. § 60.5850(b) and (c) refer only to steam generating units (*i.e.*, utility boilers)—not stationary combustion turbines—consistent with EPA's discussion of the Proposal in the preamble and the proposed revision to Subpart TTTTa for coal-fired steam generating units.[45]

The Group strongly disagrees with EPA's position in the FAQs Memo that proposed § 60.5850b does not exclude stationary combustion turbines based on their construction or reconstruction date and that stationary combustion turbines currently subject to Subpart TTTT would be considered affected EGUs for purposes of the emission guidelines. First, EPA's position contradicts how a "new source" in Section 111(a)(2) and an "existing source" in Section 111(a)(6) are defined in the CAA. As explained above, an existing source cannot also be a new source—*i.e.*, stationary combustion turbines that are subject to Subpart TTTT are "new sources" since they are sources to which a Section 111 GHG standard applies and thus they also cannot be "existing sources" subject to the proposed GHG emission guidelines.

Second, EPA's position is inconsistent with the Proposal, in which the proposed regulatory text makes clear that "EGUs" also encompass stationary combustion turbines, and nowhere in the Proposal's preamble does EPA state otherwise. Contrary to EPA's assertion in the FAQs Memo, proposed § 60.5850b clearly provides exclusions based on construction or reconstruction dates that are applicable to EGUs, and the definition of "affected EGUs" in proposed § 60.5880b explicitly includes stationary combustion turbines.[46] Moreover, proposed § 60.5850b(b) states that new or reconstructed EGUs that are currently subject to 40 C.F.R. Part 60 Subpart TTTT that commenced construction after the Subpart TTTT applicability date are excluded from being "affected EGUs."[47] The Subpart TTTT applicability date is January 8, 2014 (new EGUs) and June 18, 2014 (reconstructed EGUs).[48] Concerning this provision, the definition of EGU expressly includes "stationary combustion turbines."[49]

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[44] FAQs Memo at 2.

[45] *See id.* at 2–3 (citing proposed § 60.5850(b), (c) ("EGUs that are excluded from being affected EGUs are . . . (b) [n]ew or reconstructed EGUs that are subject to 40 CFR part 60 subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date; (c) [m]odified EGUs that are subject to 40 CFR part 60 subpart TTTTa of this part as a result of commencing modification after the TTTTa applicability date")); *see also id.* at 2 (citing proposed § 5509a(a) ("[T]he GHG standards [included in this subpart] apply to certain 'coal-fired steam generating unit[s] or IGCC [integrated gasification combined cycle facility]' that commence a modification after May 23, 2023")).

[46] And this concern raised by the Group, among others discussed in this Section, further demonstrates why EPA must publish regulatory text in the *Federal Register* (as discussed in Section IV.B, *supra*), and not attempt to clarify its intent with a memorandum added to the docket weeks after publication of a proposal.

[47] *See* proposed 40 C.F.R. § 60.5850b(b).

[48] *See* 40 C.F.R. § 60.5508.

[49] *See id.* § 60.5580.

Therefore, according to both the current regulatory text in Subpart TTTT and the proposed regulatory text in Subpart UUUUb, stationary combustion turbines that are already subject to Subpart TTTT are excluded from also being subject to the proposed Subpart UUUUb standards.[50] EPA has not, in the Proposal or even in the FAQs Memo, pointed to any separate definition of an EGU that excludes stationary combustion turbines or otherwise identified any distinction between stationary combustion turbines and steam electric generating units that would warrant disparate treatment under Section 111. Nor could the Agency do so. The CAA does not allow EPA to carve out exceptions to the definition of an existing source such that a new combustion turbine that is subject to a standard under the NSPS also could be considered an existing source that is subject at the same time to a Section 111(d) standard for the same pollutant.

Third, in proposing to regulate new stationary combustion turbines subject to Subpart TTTT under the proposed Section 111(d) guidelines, EPA's position in the FAQs Memo would clearly exceed its statutory authority. The CAA created a clear distinction between standards of performance for new stationary sources, as defined in Section 111(a), and standards of performance for existing sources that are subject to Section 111(d).[51] As discussed above, the proposed regulatory text maintains this distinction, noting that "new" sources built after January 8, 2014, remain subject to Subpart TTTT, and "new" sources built after May 23, 2023,[52] would be subject to proposed Subpart TTTTa. EPA's position in the FAQs Memo, however, blurs this distinction and therefore contradicts the statute. There is no ambiguity in the CAA requiring EPA to interpret congressional intent. The CAA does not grant EPA the authority to recategorize what is "new" and what is "existing," nor does it authorize the Agency to apply Section 111(d) to sources already subject to a NSPS for the same pollutant. EPA has pointed to no legal authority for it to do so.

The Class of '85 recognizes that EPA issued a rule for municipal landfills that revised emissions standards for both the NSPS and existing source emission guidelines and applied the revised existing source standards to landfills that were previously designated as new sources.[53] However, that is not the case here; there are no revised emission guidelines at issue. Further, although the landfill rule was challenged in *National Waste & Recycling Association v. EPA*, No. 16-1371 (D.C. Cir. filed 2016), that case has been held in abeyance, with no briefing or oral argument scheduled.[54] Accordingly, whether EPA has the authority to regulate new sources that are subject to a NSPS as existing sources for Section 111(d) purposes for regulation of the same pollutant addressed in the NSPS has yet to be addressed by a court. Further, EPA included no legal analysis in its landfill rule regarding how a landfill subject to the NSPS as a new source could

[50] *See* 88 Fed. Reg. at 33,280 ("The EPA is also proposing that stationary combustion turbines that commenced construction after January 8, 2014 or reconstruction after June 18, 2014 and before May 23, 2023 that meet the relevant applicability criteria would be subject to 40 CFR part 60, subpart TTTT.").

[51] 42 U.S.C. § 7411.

[52] As noted in Section IV.B, *supra*, the Group disagrees that the applicability date for Subpart TTTTa can be May 23, 2023, as the proposed regulation has not been published in the *Federal Register*.

[53] *See* 81 Fed. Reg. 59,276 (Aug. 29, 2016).

[54] Petitioners challenged EPA's "authority to revise to make more stringent previously promulgated CAA 111(d) emission guidelines." *See, e.g.*, Nonbinding Statement of Issues of Petitioner Utility Air Regulatory Group, *Utility Air Regulatory Group v. EPA*, No. 16-1374 (consolidated with No. 16-1371) (D.C. Cir. filed Dec. 1, 2016). It is not clear whether petitioners also intended to challenge EPA's determination that landfills subject to the NSPS as new sources also could be considered as existing sources for purposes of the revised Section 111(d) standards.

simultaneously be considered an existing source subject to the revised Section 111(d) emission guidelines.

Fourth, regulating stationary combustion turbines subject to Subpart TTTT under the proposed Section 111(d) emission guidelines violates procedural due process. The requirements of Subpart TTTT were incorporated into the design and construction of these combustion turbines. Several combustion turbines subject to Subpart TTTT are still under construction and have not yet begun operation and for which there already are legally binding contracts in place that state the requirements and guarantees under which the units are being manufactured. The owners/operators of these units could not have known that EPA would impose standards for existing EGUs to which they also would become subject. The proposed Section 111(d) standards are likely to affect the design and costs of the units, and the contracts that already are in place. Some units that were recently constructed or are still in the process of being constructed may be rendered uneconomical by the emission guidelines and the unexpected revision to BSER that they are now facing. They likely would face substantial additional costs that would put them at a detriment in the market if they were to become subject to the Subpart UUUUb emission guidelines.

Finally, should EPA adopt the position outlined in the FAQs Memo in any final rule, the Agency will have violated the APA by failing to provide notice and opportunity for comment on such position, since the proposed regulatory text unambiguously excludes stationary combustion turbines subject to Subpart TTTT; at minimum, EPA's position in the FAQs Memo should have been detailed in the Proposal (it is not). The legal significance of this Memo is questionable given that generating additional documents after the *Federal Register* notice would be an inappropriate way to build an administrative record—otherwise, the Agency could sandbag the rulemaking process by uploading post hoc documents up until the comment deadline, thereby providing little to no time for the public to react. Thus, should EPA wish to adopt the position articulated in its FAQs Memo, the Agency must first issue a supplemental proposal to provide fair notice of this changed position. Relatedly, the release of the FAQs Memo and the substantive position taken by EPA in the document are even more reasons commenters should be given additional time to digest and provide feedback on the Proposal, as discussed *supra* Section III.

V. COMMENTS ON THE PROPOSED EMISSION GUIDELINES FOR EXISTING EGUS

A. The Proposed Provisions Regarding Large, Frequently Used Existing Fossil Fuel-Fired Stationary Combustion Turbines Are Not Well-Developed

The Proposal establishes a subcategory for large, frequently used existing fossil fuel-fired stationary combustion turbines and defines them as stationary combustion turbines that have an electric generating capacity greater than 300 MW and a capacity factor of greater than 50 percent, which primarily encompasses existing natural gas-fired combined cycle combustion turbines.[55] EPA is proposing two pathways as BSER for such combustion turbines: (1) use of CCS by 2035, or (2) co-firing 30 percent by volume low-GHG hydrogen by 2032 and co-firing 96 percent by volume low-GHG hydrogen by 2038. For stationary combustion turbines selecting the CCS pathway, EPA is proposing that the presumptively approvable standard is an 89 percent reduction

[55] *See* 88 Fed. Reg. at 33,362.

in the unit's annual baseline emission rate in lb CO_2/MWh-gross.[56] For stationary combustion turbines selecting the low-GHG hydrogen co-firing pathway, EPA is proposing that the presumptively approvable standard is a 12 percent reduction in the unit's annual baseline emission rate in lb CO_2/MWh-gross beginning January 1, 2032, and the presumptively approvable standard beginning January 1, 2038, is an 88.4 percent reduction in the unit's annual baseline emission rate in lb CO_2/MWh-gross.[57]

The Proposal requires the combustion of "low-GHG hydrogen." This is defined in proposed 40 C.F.R. Subpart TTTTa (which also would apply to Subpart UUUUb) as hydrogen that is "produced through a process that results in a GHG emission rate of less than 0.45 kg of CO_2 equivalent per kilogram of hydrogen (kg CO_2e/kg H_2) on a well-to-gate basis."[58] According to EPA, the proposed definition is consistent with the definitions used in the Internal Revenue Code ("I.R.C.") Section 45V under the IRA.[59]

1. EPA should issue a separate rulemaking on regulating GHG emissions from existing large, frequently operated stationary combustion turbines

The Group strongly urges EPA to address the proposed standards for large, frequently operated existing fossil fuel-fired stationary combustion turbines in a separate rulemaking.[60] These combustion turbines are crucial to maintaining grid reliability as the sector transitions to clean energy, and EPA needs to consider and address several issues omitted from the Proposal (*see* further discussion in this Section, *infra*) to ensure that the requirements applicable to these units have been adequately analyzed and justified. EPA also should thoroughly consider the possible consequences of disrupting grid reliability by overregulating such base-load units, including conducting detailed and transparent discussions with the ISOs and RTOs.

EPA defines large, frequently used stationary combustion turbines as units with greater than 300 MW electric generating capacity and more than 50 percent annual capacity factor but nowhere in the Proposal explains what either threshold means.[61] Specifically, the Proposal does not explain:

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[56] *See id.* at 33,366.

[57] *See id.* at 33,380–81.

[58] Proposed § 60.5580a.

[59] *See* 88 Fed. Reg. at 33,304; *see also* I.R.C. § 45V(b)(2)(D) (providing that the "applicable percentage" for calculating the amount of clean hydrogen production credit for any taxable year is 100 percent for "any qualified clean hydrogen which is produced though a process that results in a lifecycle greenhouse gas emissions rate of less than 0.45 kilograms of CO_2e per kilogram of hydrogen").

[60] If EPA intends to regulate smaller, less frequently operated fossil fuel-fired stationary combustion turbines, EPA should reissue its proposal to regulate large, frequently used existing fossil fuel-fired stationary combustion turbines at the same time that it proposes to regulate such other stationary combustion turbines. This would allow the electric generating industry to holistically assess how EPA's intent to regulate GHGs from stationary fossil fuel-fired combustion turbines may impact electricity reliability and affordability.

[61] *See also* proposed § 60.5850b(a) (excluding from being an "affected EGU" "[n]atural gas fired stationary combustion turbines with an electric generating capacity equal to or less than 300 MW or with an electric generating capacity of more than 300 MW and that operate at an annual capacity factor equal to or less than 50 percent").

- What is meant by "electric generating capacity," *i.e.*, summer or winter net dependable capacity or by some other measure.

- Whether the steam portion of natural gas combined cycle ("NGCC") units is included in calculating electric generating capacity.

- How the 50 percent annual capacity threshold is determined, whether it is by reference to a historical lookback period, or whether a forward-looking commitment to operate at less than a 50 percent annual capacity factor would be sufficient for the unit to be excluded from being considered an "affected EGU."

- Whether the determination of a unit's capacity factor is a one-time or recurring determination, and whether a unit that is initially classified as "frequently used" may subsequently change its designation by operating or committing to operate at less than 50 percent annual capacity in the future.

- Whether an owner/operator of an existing stationary combustion turbine can self-certify whether their units fall within the defined subcategory.

- Whether the electric generating capacity can be limited by a permit condition.

- Whether state plans could exempt an existing stationary combustion turbine that only exceeds the 50 percent annual capacity threshold due to operation to address reliability or for grid stability purposes.[62]

Overall, based on the Proposal and the proposed regulatory text, it is not possible to definitively determine whether a given unit would or would not be subject to the proposed requirements for existing "large and frequently used" combustion turbines. This remains true even with the supposed "clarifications" proffered in the Agency's FAQs Memo. And given all of the outstanding issues that EPA must address with the regulation of existing stationary combustion turbines greater than 300 MW that have not been addressed in the Proposal—as partially evidenced by EPA's decision to issue the FAQs Memo and as further evidenced by the concerns and questions raised in these comments—the Group requests that EPA withdraw the proposed regulation of existing stationary combustion turbines from this Proposal and issue a separate proposal after EPA has further considered and addressed all of the unanswered questions related to its proposed regulation of such units. Although EPA issued its FAQs Memo to address applicability questions with respect to existing stationary combustion turbines, the information EPA provided in the FAQs Memo[63] is not included either in the description of the proposed emission standards in the Proposal, or in the proposed Subpart UUUUb regulatory text that was posted to the docket.

[62] Such an exemption would be similar to the one for an episodic generator under the Resource Conservation and Recovery Act.

[63] Once again, the Class of '85 notes its objection to the FAQs Memo, which does not satisfy the Agency's obligation under the APA to provide fair notice of the issues raised therein and thus cannot be considered a legitimate administrative record, as discussed *supra* Section IV.C.3.

Further, the Proposal indicates that stationary combustion turbines greater than 300 MW "have applicable standards of performance *only when* they operate at an annual capacity factor of greater than 50 percent" and "[w]hen they operate at an annual capacity factor of 50 percent or less, they are not subject to standards of performance."[64] In addition, EPA's power sector modeling posted in the Proposal's rulemaking docket appears to suggest that many combustion turbine units would choose to initially meet the 2032 low-GHG hydrogen co-firing standard, but then subsequently limit their operation to less than 50 percent capacity factor in later years, which would avoid the much more substantial investment necessary to meet the proposed Phase 3 low-GHG hydrogen co-firing standard.[65] The fact that EPA's own modeling includes such an option, coupled with EPA's statement in the Proposal, strongly suggests that the Agency does not view there to be a "once in, always in" requirement for stationary combustion turbines.

The Class of '85 strongly supports such compliance flexibility and agrees that stationary combustion turbines should have the opportunity to limit their operations to fall below the electric generating capacity and/or annual capacity factor thresholds. Yet, such flexibility is not reflected clearly in the Proposal or the proposed regulatory text, nor does the Proposal explain how this concept would work in practice. For instance, would a stationary combustion turbine that is greater than 300 MW be exempt from the standard in the first year that it falls below 50 percent annual capacity or just for subsequent years? Alternatively, if a stationary combustion turbine greater than 300 MW is operating at less than 50 percent annual capacity but exceeds that threshold for one year, would the applicable standard of performance apply in that year? If compliance was required in that year, a combustion turbine might have difficulty meeting the emission standard, particularly if operation above the 50 percent annual capacity threshold was unplanned and limited in duration, with the unit falling below the 50 percent annual capacity threshold in subsequent years.

EPA should explain how compliance for stationary combustion turbines greater than 300 MW electric generating capacity and greater than an annual capacity factor of 50 percent is meant to be determined. The Class of '85 recommends that EPA use a three-year average for calculating the average capacity factor instead of the proposed annual average to align with other rules establishing capacity factors generally based on a three-year average.[66] Moreover, in the event that an ISO, RTO, or other regional reliability authority calls for an emergency generation event, EPA should exclude the operating hours during the emergency event when calculating the average capacity for purposes of the capacity factor threshold.

2. EPA must clarify how to determine the 300 MW electric generating capacity and 50 percent annual capacity factor thresholds

As noted above, the Proposal does not define the electric generating capacity or how it is determined for NGCCs, nor does the Proposal identify how to determine whether a stationary combustion turbine exceeds an annual capacity factor of 50 percent. In the FAQs Memo, EPA asserts that the 300 MW threshold includes (1) the electric generating capacity of the combustion

[64] 88 Fed. Reg. at 33,394 (emphasis added).

[65] *See* Additional Modeling Memo at 5.

[66] *See*, *e.g.*, 40 C.F.R. § 72.2 (definition of "peaking unit" for purposes of 40 C.F.R. Part 75, Appendix E); 40 C.F.R. § 63.10042 (definition of "natural gas-fired electric utility steam generating unit").

turbine; and (2) the electric generating capacity of any associated steam turbines apportioned/prorated to the combustion turbine, where:

- For a simple cycle combustion turbine, the total heat input and total electric generating capacity of the unit is attributable directly to the fuel combusted (heat input, MMBtu/hr) and the electricity generated (capacity, MW);

- For a NGCC unit, the total heat input to the unit includes the fuel combusted in the combustion turbine and the fuel combusted in any associated duct burners; and

- For a NGCC unit, the electric generating capacity is based on the electric generating capacity of the combustion turbine and the prorated (apportioned) electric generating capacity of the steam turbine.[67]

EPA needs to address how the 300 MW threshold is determined in the Proposal, not merely in a memorandum that is included in the docket weeks after the Proposal was published in the *Federal Register*.

Further, based on the Proposal, the 300 MW threshold is to be calculated per unit, not by plant: "EPA is proposing emission guidelines for *units* with a capacity factor greater than 50 percent and a capacity of greater than 300 MW."[68] This is confirmed by the proposed regulatory text.[69] The Class of '85 supports determining the threshold *per unit*. Applicability of the NSPS to stationary combustion turbines is determined on a unit basis and, accordingly, it is appropriate that applicability of the emission guidelines for existing stationary combustion turbines likewise be determined on a unit basis. However, in the Additional Modeling Memo,[70] EPA states that, although the Proposal applies the 300 MW threshold for existing stationary combustion turbines on a unit-level basis and that all of its modeling thus far is on that same basis, "comments from stakeholders to date have led the EPA to also consider applying the threshold on a plant-level basis."[71]

This is new information that is absent from the Proposal and would be a significant substantive change. It also does not account for the reality that there are plants with different owners, or units with different owners, and different types of units at the same plant (*e.g.*, there may be stationary combustion turbines at the same site as steam generating units or renewables such as solar). Under EPA's contemplated plant-wide approach, the presence of such other generating sources could now change the regulatory outcome because those other sources would count toward the 300 MW threshold. It also would capture smaller stationary combustion turbines located at the same plant that EPA patently did not intend to regulate under the Proposal and for

[67] FAQs Memo at 4.

[68] 88 Fed. Reg. at 33,362 (emphasis added).

[69] *See* proposed § 60.5880b (definition of stationary combustion turbine referring to an individual combustion turbine and its constitutive parts rather than a plant).

[70] Similar to the FAQs Memo, the Additional Modeling Memo cannot be considered a legitimate administrative record since it was provided after the date of *Federal Register* publication of the Proposal and the public was not given adequate time to digest and provide comments.

[71] *See* Additional Modeling Memo at 5.

which EPA has not determined BSER, proposed emission guidelines, or otherwise evaluated the costs of controls.[72] Accordingly, the Class of '85 strongly opposes basing the electric generating capacity on a plant-level basis. EPA should maintain the electric generating capacity threshold on a unit-level basis.

EPA also states in the Additional Modeling Memo that it "is considering the appropriate MW threshold for such a plant-level approach and whether such an approach should also include a unit-level MW threshold."[73] If EPA intends to apply a MW threshold on a plant-level basis, it should be significantly higher than the unit-level threshold, and the unit-level threshold should not be lower than 300 MW. Further, if EPA is contemplating a plant-level threshold, EPA should raise it in a separate rulemaking along with updated modeling, to ensure that EGUs and other interested stakeholders have an opportunity to fully analyze its implications and provide comments to the Agency.

The Agency also needs to address how the CO_2 emission rate (lb/MWh) should be calculated from multi-shaft NGCCs—specifically, by each combustion turbine with an apportionment of steam turbine MWs produced or as a combined unit. The Agency also should eliminate the concept of heat recovery steam generator ("HRSG") capacity apportionment because it results in penalizing combined cycle units that only recover waste heat to augment the output of gas turbines. The steam produced by the HRSG does not cause any increase in CO_2 emissions. Instead, EPA should establish the applicability of the standard based solely on the size of the combustion turbine.

3. EPA needs to define the electric generating capacity

EPA needs to include a definition of "electric generating capacity" in the final emission guidelines. To account for ambient conditions, EPA should use the "net summer capacity" rating, defined as "The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.)"[74] EPA should not use nameplate capacity because this can vary greatly from the actual capacity of which a unit is capable depending on degradation and other factors.

For NGCCs, the electric generating capacity should be calculated based on heat input only to the combustion turbine, not the duct burners. If EPA requires duct burners to be included in the capacity threshold calculation, EPA should raise the capacity to over 350 MW or otherwise exempt the use of duct burners during resource adequacy events within RTOs/ISOs, or other system reliability authorities.

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[72] *See, e.g.*, 88 Fed. Reg. at 33,362 (identifying that EPA is proposing emission guidelines for units that exceed the 300 MW/50 percent capacity factor thresholds).

[73] Additional Modeling Memo at 5.

[74] U.S. Energy Info. Admin. ("EIA"), EIA860 (last visited July 31, 2023), https://www.eia.gov/tools/glossary/index.php?id=net%20summer%20capacity#:~:text=Net%20summer%20capacity%3A%20The%20maximum,June%201%20through%20September%2030.

B. EPA Should Reconsider BSER for Stationary Combustion Turbines

EPA is proposing that BSER for existing large, frequently used stationary combustion turbines is CCS or low-GHG hydrogen co-firing. As discussed above in Section IV.A, *supra*, neither technology has been adequately demonstrated and thus, should not be considered BSER at this time. At the least, EPA must reconsider these technologies for existing stationary combustion turbines. BSER for existing units should not be the same as BSER for new units (*see* Section VI.A.2, *infra*, on BSER for new Base-load fossil fuel-fired stationary combustion turbines) because costs are far greater for retrofits than for new builds. Further, the Group recommends that, if EPA retains CCS and low-GHG hydrogen co-firing as BSER for large, frequently operated existing stationary combustion turbines, the Agency should delay the proposed schedule for installation of these technologies to accommodate feasible time frames that allow for an orderly transition away from coal-fired generation and to provide adequate time for permitting, regulatory approvals, development of required infrastructure, construction, and commissioning.

1. EPA should not establish CCS as BSER given that CCS has not yet been "adequately demonstrated" for stationary combustion turbines

EPA should not set CCS as BSER for large, frequently used existing stationary combustion turbines. The Group is concerned that units would not be able to implement CCS by the proposed compliance date of 2035. First, there is a significant difference between requiring one or a few sources to adopt a particular technology versus an entire industry scaling up a technology that is still in its research and development phase and moving into beta testing. Technology/vendor selection, engineering, materials procurement, construction, installation, testing, transportation of CO_2—and the related permitting, regulatory compliance, and land-rights acquisition for such infrastructure—take considerable time. Intellectual property rights also may need to be negotiated given the nascent state of technology. Additionally, these projects will require coordination of transmission infrastructure construction and generator outages/commissioning activities to maintain system reliability. Overall, these projects, while dependent on market conditions, geography (including geological conditions), public opposition, etc., could take anywhere between eight to ten years. In addition, regulatory approvals (such as from public service commissions) will be based on requirements specified in a final, approved state plan, which means the developmental timeframe would not even begin until after EPA issues final approval of the relevant state plan.

There also are no existing provisions establishing long-term liability and financial assurance for sequestration sites. To avoid potentially significant future environmental liabilities, EPA first needs to establish a long-term liability, closure and post-closure care, and financial assurance process for CCS projects so that such projects are certified according to a consensus standard and can be constructed and operated in accordance with that standard prior to establishing CCS as BSER. And if a facility meets the criteria set forth in the consensus standard, the facility should be released from liability if carbon storage locations later turn out to have safety or environmental impacts at an unknown future date.

Second, given the nascent nature of these technologies, more research is needed, particularly for gas-fired stationary combustion turbines, as the Group previously explained in its

comments on EPA's non-rulemaking docket on reducing GHGs from fossil fuel-fired EGUs.[75] There are no commercial or demonstration stationary combustion turbines with CCS technology in the United States. Further, there are geographic and geological limitations, in addition to constraints on water availability, that hinder CCS, and more research, development, and demonstration work is needed to determine whether CCS is a viable option for gas-fired stationary combustion turbines. For instance, if the geography or geology at the site does not support CCS, the CO_2 would need to be transported off-site, which presents additional technical and local community challenges and safety concerns, along with expanded permitting and construction timeframes (all of which are concerns outside the fenceline).

Third, the legal infrastructure to govern CCS is not yet well-developed. In many cases, states have not yet established who owns the pore spaces in which CO_2 would be stored. For example, it remains unclear if the owner would be the owner of the surface area, owner of the mineral rights, or someone who specifically buys that privilege. Further, it remains unclear what happens if a storage site flows under a state line into another jurisdiction. These issues have been worked out over decades of oil and gas exploration and recovery cases, but court battles over these issues could hold up operation of CCS, which could ultimately delay putting multi-billion dollar power plants into service.

CCS has only been deployed on a handful of baseload coal-fired EGUs—two in operation in North America with only one in the United States.[76] However, research and testing of amine technologies for CO_2 removal on gas-fired stationary combustion turbines have only recently begun.[77] More importantly, it is unclear whether the variable operating conditions of gas-fired stationary combustion turbines can support CCS, much less at the level of CO_2 removal proposed by EPA as BSER. Such EGUs need to quickly respond to support more flexible electric generating scenarios, which entail a wide range of operating conditions, including high ramping rates, periods of minimum load operations, and the potential for multiple startups and shutdowns of the unit per day. Additionally, CCS technology would require energy from the combustion turbines to operate, which would decrease the efficiency of the combustion turbine, decrease the unit's contribution to serving load requirements for system reliability, and potentially delay broader economy-wide decarbonization by reducing electrification opportunities. All of this needs further analysis.

Should CCS be adequately demonstrated prior to the proposed compliance date of 2035 for stationary combustion turbines, there are still multiple additional hurdles that may hinder the

[75] The Group incorporates its comments on EPA's non-rulemaking docket on Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units, Dkt ID No. EPA-HQ-OAR-2022-0723-0037 (posted Mar. 6, 2023) (Attachment B).

[76] The one project in the United States where CCS had been deployed on a coal-fired facility, PetraNova, does not qualify as being commercially available as it is assisted by U.S. government subsidies. *See* 88 Fed. Reg. at 33,290–92 (acknowledging that the Agency is precluded from relying solely on the experiences of facilities that received funding). PetraNova also stopped operating because the price of oil recovered from the injection of CO_2 into oil wells was not sufficient to justify continued operation and has not yet returned to service. EPA fails to point to any other information pertaining to CCS deployment in the United States that would show that the technology has been adequately demonstrated.

[77] EPA also refers to the Bellingham Energy Center in south central Massachusetts to demonstrate that CCS was "successfully applied to an existing combined cycle combustion turbine EGU." *See, e.g., id.* at 33,254. But that facility was used in the 1990s primarily to serve the food industry, and was far too small of a unit to demonstrate feasibility for the scale that the Agency is advocating.

deployment of CCS within the proposed compliance timeframe. CCS is not simply an add-on control. CCS requires significant retrofitting and engineering. CCS technology also might require energy for directing steam from a NGCC's HRSGs to the carbon capture unit.[78] This would result in the stationary combustion turbine firing more gas and producing a lower overall amount of net electricity to supply to the grid, thus reducing the efficiency of the stationary combustion turbine as well as its ability to support grid reliability. Current research and engineering evaluations are focused on addressing this issue, but such results to date have not been demonstrated.

For these reasons, the Group reiterates that CCS for gas-fired stationary combustion turbines has not been "adequately demonstrated" to be BSER. But, to the extent EPA finalizes a determination that it has, the Group strongly recommends that EPA include provisions to provide relief to sources in the event that necessary technology advancements and infrastructure deployment do not occur by a "date certain" (such as automatic compliance deadline extensions/off-ramps if technology performance issues render the required emission standards infeasible).[79] Such backstop provisions would provide companies with needed certainty for making operational and investment decisions to meet the proposed compliance deadlines, since it is likely that these units will still be needed to help protect the integrity of the grid.

2. EPA should not establish low-GHG hydrogen co-firing as BSER given that the technology has not been adequately demonstrated

Low-GHG hydrogen co-firing is still under development and has yet to be proven at scale, let alone be commercially available. As a starter, storing hydrogen in tanks or geological formations is expensive and inherently inefficient due to energy losses from compression and re-expansion of the gas. There also will be a significant spike in water usage to produce hydrogen in the projected volumes—this includes hydrolyzed water, reject water, and cooling water. And, as of now, the energy to make hydrogen must be derived from *excess* renewables (in other words, only when production of renewable energy would be curtailed due to the lack of demand in real time) to be technologically and economically feasible. Finally, whatever small quantities of low-GHG hydrogen that could be created with excess renewables would first be directed at existing uses of hydrogen, such as ammonia production.

The status of the hydrogen economy illustrates the Group's position. Researchers at the National Renewable Energy Laboratory are currently working on challenges to accelerate low-GHG hydrogen production, which include: (1) improving fuel cell technology and materials needed for fuel cells; (2) development of technology to efficiently and cost-effectively make hydrogen from renewable sources and other carbon-free sources (such as nuclear); and (3) developing technology to efficiently and cost-effectively store and transport hydrogen.[80] Further, the Department of Energy ("DOE") is still in the process of reviewing applications for the Regional Clean Hydrogen Hubs ("H2Hubs") program and has yet to even select awardees for

[78] *See id.* at 33,349 (discussing the energy requirement for a steam generating unit that employs CCS).

[79] EPA has offered such relief in the past. For example, for the MATS rule, EPA allowed certain units to continue operating past the compliance deadline to protect the grid in a particular region.

[80] Nat'l Renewable Energy Lab'y, *Hydrogen Basics* (last visited July 21, 2023), https://www.nrel.gov/research/eds-hydrogen.html.

funding.[81] Even DOE recognizes that there are challenges to low-GHG hydrogen that need to be resolved.[82] Accordingly, EPA must allow time for low-GHG hydrogen co-firing to advance and be adequately demonstrated to ensure reliable and consistent performance.

In addition, EPA's proposed requirement that hydrogen co-firing be limited to low-GHG hydrogen is outside of the scope of Section 111(d) as applied to EGUs. EPA's proposal is directed at production of hydrogen, which is beyond the control of the electric generating plant. When a viable pipeline network for hydrogen transportation is developed, it is likely that hydrogen from a variety of processes will be commingled, and electric generators will not be able to certify that they have been supplied with low-GHG hydrogen. And hydrogen, no matter how it is produced, would not result in GHG emissions when burned at a stationary combustion turbine. The I.R.C. provides tax incentives for the production of low GHG-hydrogen that are likely to incentivize its production, which would support its use in hydrogen co-firing at stationary combustion turbines and EPA should not attempt to separately mandate its use as part of the GHG emission guidelines. To the extent additional regulation is needed to encourage the production of low-GHG hydrogen, EPA should direct any requirements related to the method of production to the fuel producers rather than the electric generating industry. Nonetheless, if EPA intends to include co-firing of low-GHG hydrogen as BSER in the final emission guidelines, EPA should include all hydrogen at an intensity of 4.0 kg eCO_2/kg H_2 (as provided in the IRA and the DOE's clean hydrogen policies) or lower to increase the eligible supply of low-GHG hydrogen.

Additionally, significant infrastructure development, including hydrogen pipeline construction, storage capacity, and adequate water supplies, would be needed to support low-GHG hydrogen generation. The Proposal cites to 1,600 miles of hydrogen gas pipelines being used in refineries along the Gulf Coast as proof that hydrogen pipelines can be built.[83] The Proposal, however, ignores several major concerns regarding hydrogen pipelines that must be addressed for safe transport.[84] These concerns include the high flammability range of hydrogen (to the point of potentially being explosive) and contamination issues for certain hydrogen odorants that are still being studied. EPA has not justified how hydrogen pipelines are safer than, or at least equivalent to, natural gas or oil pipelines such that proposed pipelines would not be cancelled or significantly delayed due to citizen opposition, particularly in communities with environmental justice ("EJ") concerns. Just one hydrogen fire could lead to the mandated shutdown of all hydrogen pipelines. Further, there currently is no federal body that approves the siting of dedicated hydrogen pipelines. This means that individual states must approve the construction of hydrogen pipelines, which complicates and extends the approval process for connecting these pipelines to regional hubs. Aside from hydrogen pipelines, there are various concerns with low-GHG hydrogen co-firing, which even EPA acknowledges. To start, EPA understands there needs to be lead time for

[81] *See* U.S. Dep't of Energy, Office of Clean Energy Demonstrations, *Regional Clean Hydrogen Hubs* (last visited July 22, 2023), https://www.energy.gov/oced/regional-clean-hydrogen-hubs-notifications#:~:text=The%20final%20application%20deadline%20is,well%20as%20related%20FAQ's%20below.

[82] *See generally* U.S. Dep't of Energy, *Pathways to Commercial Liftoff: Clean Hydrogen* (Mar. 2023), https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[83] *See* 88 Fed. Reg. at 33,313. The Proposal does not delve into the safety monitoring and protection systems installed for refinery hydrogen gas pipelines and, more crucially, whether they are desirable in non-industrial areas.

[84] Paul W. Parfomak, Cong. Rsch. Serv., R46700, *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy* (2021), https://crsreports.congress.gov/product/pdf/R/R46700.

infrastructure to be built out to support low-GHG hydrogen co-firing.[85] Further, EPA acknowledges that a self-sustaining market for low-GHG hydrogen does not currently exist.[86] Low-GHG hydrogen co-firing also has the potential to result in increased water use, which could create additional problems for water-constrained states.

Should EPA finalize a determination that low-GHG hydrogen co-firing is BSER, EPA needs to ensure that this standard does not force sources to violate other CAA requirements, or at least make sure that compliance requirements are harmonized. In proposing to establish low-GHG hydrogen co-firing as BSER, EPA has acknowledged that co-firing has the potential to generate more thermal NOx emissions due to the increased flame temperature,[87] which could be especially problematic in ozone nonattainment areas such as Los Angeles or Houston.

This is not merely a hypothetical conjecture. One member of the Group owns and operates a natural gas combined cycle fleet in an ozone nonattainment area. The area was recently redesignated as moderate nonattainment for the 2015 ozone standard, with attainment required by August 3, 2024. Currently, it is estimated that an approximate 50 percent reduction in nonattainment area anthropogenic NOx and VOC emissions is necessary to demonstrate attainment in the 2023 ozone season. Relatedly, it is unlikely that the area will be able to demonstrate attainment in the 2023 ozone season or show attainment by the deadline of August 3, 2024, and the area is likely to be redesignated as serious nonattainment in the not-too-distant future. Under current regulations, units already must meet very stringent NOx limits and may be asked to further reduce NOx emissions due to the redesignation to serious nonattainment. Yet compliance with low-GHG hydrogen co-firing in this scenario would complicate these NOx emission standards because the increased flame temperature from co-firing could generate more thermal NOx emissions. If additional controls are necessary as a result, this would exacerbate the capital cost passed on to ratepayers in regulated markets and also would require careful planning and consideration. In unregulated, independent power producer markets, there is no mechanism to pass these costs along.

There also could be New Source Review ("NSR") implications from installing new controls that must be considered. The Proposal would require states to develop a plan to establish standards of performance for each affected EGU. According to EPA, major NSR requirements should not be triggered often because states have flexibility to limit emission increases associated with meeting a standard that would trigger major NSR requirements—for instance, by establishing a synthetic minor limitation.[88] Such an option might not be feasible, however, for a base-loaded gas-fired stationary combustion turbine that is necessary for grid reliability, as a synthetic minor limitation might unacceptably limit the unit's flexibility to operate as a baseload unit. In some cases, a state's minor NSR program might require additional review or public notice especially when considering the potential storage implications of hydrogen, which could require additional safety measures. Alternatively, the amount of money spent on retrofitting an older unit could be substantial to the point it could be considered "reconstruction" under CAA Sections 111 or 112.

[85] *See* 88 Fed. Reg. at 33,361.

[86] *See id.* at 33,365.

[87] *See id.* at 33,364.

[88] *See id.* at 33,408.

There are several issues associated with low-GHG hydrogen co-firing at gas-fired stationary combustion turbines that are not addressed in the Proposal. The Group requests that EPA address the following questions:

- How has EPA determined that production and distribution of low-GHG hydrogen will be sufficiently advanced for units to meet the proposed compliance dates?

- As levels of hydrogen combustion increase, combustion turbine output decreases. Has EPA accounted for the increased need for generation to offset this loss and its subsequent emissions? Can such emissions be addressed with combustor design modifications?

- How are start-up and shut-down emissions treated? And given how increased cycling would be needed to support intermittent renewable generation, has EPA calculated the subsequent overall emission impact of the increased reliance on stationary combustion turbines?

- Existing stationary combustion turbines may not have been built with metals capable of tolerating higher temperatures. Given that hydrogen burns at a much higher temperature than natural gas, has EPA determined whether existing stationary combustion turbines can accommodate hydrogen without damage?

- Transporting high purity hydrogen can lead to hydrogen embrittlement of existing piping and infrastructure. This is an issue that needs to be fully resolved prior to low-GHG hydrogen co-firing being mandated. EPA broadly claims that this issue "can be mitigated though deployment of new pipeline infrastructure designed for compatibility with support of a new combustion turbine installation."[89] What is the basis for EPA's expectation that such pipeline infrastructure can be deployed in time for units to meet the compliance deadlines?

- Will increased hydrogen production affect gas compression equipment energy requirements? Will pushing a "less dense" gas or gas blend require compressor stations to operate more? Given how many of these compressor stations are gas fired, has EPA considered emissions impacts from these sources? Even for electric compressor stations, has EPA considered the impact of potential increases in electrical consumption?

- Has EPA considered the non-air environmental impacts of the amount of water consumption necessary (*e.g.*, feedwater for electrolysis, cooling, production losses) to achieve the requisite level of low-GHG hydrogen production to enable the widespread adoption of low-GHG hydrogen co-firing within the EGU sector, and how that may strain states with limited water resources?[90]

[89] *Id.* at 33,314.

[90] *See* Milind Deo et. al., Energy & Geoscience Institute at the University of Utah, *Hydrogen Electricity Generation and Water Consumption Comparisons* (2022), https://le.utah.gov/interim/2022/pdf/00004284.pdf.

- Has EPA considered the energy loss in generating electricity to create hydrogen through electrolysis, storing the hydrogen, and then re-converting it to electricity (known as "round-trip" efficiency), which can be significant?[91]

- Has EPA determined whether low-GHG hydrogen production systems can respond to changing levels of demand, as stationary combustion turbines operate in response to public electricity demand, which can vary significantly during 24 hours, as well as weekly, monthly, and seasonally?

- Would requirements for co-firing of low-GHG hydrogen be exempted during back up operations, such as stationary combustion turbines that operate on a back-up fuel like distillate oil when natural gas is curtailed?

- Is EPA aware of any studies that have shown that co-firing low-GHG hydrogen with fuel oil operation is possible?

For the above reasons, similar to its position on CCS, *supra* Section V.B.1, the Group strongly recommends that hydrogen co-firing not be established as BSER because the technology has not been "adequately demonstrated." However, should EPA finalize the BSER as proposed, relief should be provided to units if the necessary technology/infrastructure/low-GHG hydrogen development does not occur by a "date certain." Examples of such relief include automatic compliance deadline extensions and off-ramps if technology performance issues render the required emission standards infeasible. This would provide companies much needed certainty for making operational and investment decisions to meet the proposed compliance deadlines.

Further, should EPA finalize emission guidelines for large, frequently used existing gas-fired stationary combustion turbines, EPA should provide similar latitude for such units as that provided for existing coal-fired units in the Imminent- or Near-term subcategories (discussed in Section V.F.1, *infra*). Specifically, EPA should establish subcategories for large, frequently operated stationary combustion turbines that intend to retire in the imminent- or near-term similar to the approach utilized for coal-fired EGUs, with consideration of later retirement dates for gas turbine EGUs, and set BSER for such subcategories as routine methods of operation and maintenance. This would allow such units to avoid making costly strides towards meeting BSER based on CCS or hydrogen co-firing.

[91] *See* Tom DiChristopher, *Hydrogen Technology Faces Efficiency Disadvantage in Power Storage Race*, S&P Global Market Intelligence (June 24, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/hydrogen-technology-faces-efficiency-disadvantage-in-power-storage-race-65162028#:~:text=While%20the%20production%20and%20storage,Institute%20for%20Energy%20Economics%20and; *see also* Green Car Congress, *DOE Reports Say Cumulative Investment in Hydrogen, Nuclear and Long-Duration Energy Storage Must Increase to $300B by 2030* (Mar. 23, 2023) ("[U]p to 200 GW of new renewable energy sources would be needed by 2030 to support clean hydrogen production."), https://www.greencarcongress.com/2023/03/20230323-pathways.html#:~:text=If%20water%20electrolysis%20dominates%20as,is%2050%20MMTpa%20by%202050.

C. The Group Supports EPA's Proposal Not to Impose Standards on Combustion Turbines that Solely Fire Oil

According to the proposed regulatory text of Subpart UUUUb, EPA is not proposing standards for combustion turbines that solely fire oil. Proposed § 60.5845b(b) defines an "affected EGU" as a "steam generating unit or *natural gas fired* stationary combustion turbine that meets the relevant applicability conditions." Therefore, stationary combustion turbines that fire oil would be excluded from the emission guidelines.[92] The Class of '85 supports excluding oil-fired stationary combustion turbines from the emission guidelines.

However, the Proposal does not address how the emission standards apply to dual-fuel combustion turbines—as some stationary combustion turbines fire oil during emergencies, when natural gas is unavailable, or to provide black-start capability—and it is unclear how such units are treated. The Group asks that EPA explain how dual-fuel combustion turbines are treated, including whether the proposed Subpart UUUUb GHG emission guidelines would apply and if so, under what circumstances. EPA also must explain how any periods of fuel oil operation should be addressed in determining compliance with any applicable emission standards. To the extent EPA intends to regulate dual fuel-fired stationary combustion turbines, the Agency should publish a supplemental proposal to address such units since the Proposal currently lacks any discussion of dual fuel-fired units and any proposal to regulate such units would be a significant measure for which the regulated community should be offered the opportunity to comment.

D. EPA Should Not Establish BSER for Any Additional Classes of Existing Stationary Combustion Turbines

EPA should not establish BSER for any additional classes of existing stationary combustion turbines. Flexible natural gas generation is critical to integration and operation of renewables, and smaller, more intermittently operated turbines are uniquely suited to meet the need to augment renewables, which are inherently impacted by weather conditions and time of day. Some units also will be necessary to replace capacity lost due to coal-fired EGU retirements. The potential reductions in GHG emissions that could be achieved by regulating such units does not warrant the impacts to system reliability during the energy transition.

Should the Agency intend to establish and address other subcategories of existing stationary combustion turbines, EPA should refrain from finalizing its proposal on large, frequently operated stationary combustion turbines. EPA should issue a separate rulemaking that addresses all existing stationary combustion turbines that the Agency proposes to regulate to allow the industry an opportunity to fully evaluate the impacts of regulation on the stationary combustion turbine fleet.

E. The Group Supports EPA's Proposal Regarding Existing Gas-Fired and Oil-Fired Steam Generating Units

The Proposal would establish subcategories of existing gas-fired and oil-fired steam generating units by load level: (1) "Low" (annual capacity factor less than 8 percent);

[92] Proposed § 60.5845b(b) (emphasis added).

(2) "Intermediate" (annual capacity factor greater than or equal to 8 percent and less than 45 percent); and (3) "Base" (annual capacity factor equal to or greater than 45 percent). There also are separate subcategories for continental and non-continental oil-fired steam generating units.[93] In general terms, aside from Low-load, the BSER for existing gas-fired and oil-fired steam generating units is routine methods of operation and maintenance. EPA is not proposing BSER requirements for Low-load units.[94]

The Group supports the BSER for existing gas-fired and oil-fired steam generating units and EPA's determination not to impose requirements on Low-load units. The Group, however, asks that EPA modify the definition of "natural gas-fired steam generating unit" in proposed § 60.5880b (revision in red) so that it reads as follows:

> [A]n electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired or oil-fired steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, ~~and~~ or that no longer retains the capability to fire coal after December 31, 2029.

The modification would facilitate coal-fired units' ability to transition to natural gas, as the modified definition would allow a converted coal-fired unit to be defined as a gas-fired unit without having fired gas in the years prior to 2030, and also would be consistent with the definition of "coal-fired steam generating unit."[95] With a permit limit that makes the conversion enforceable as of January 1, 2030, such coal-fired units would appropriately fall into one of the existing gas-fired steam generating unit subcategories, rather than into one of the existing coal-fired unit subcategories, and state plans could appropriately identify the proper subcategory into which the unit would fall as of January 1, 2030.

F. EPA Should Reconsider Certain Aspects of the Proposal Regarding Existing Coal-Fired Steam Generating Units

The Proposal subcategorizes existing coal-fired steam generating units primarily by the unit's operating horizon, as well as by load level. These subcategories include: (1) "Imminent-term" (cease operating before January 1, 2032); (2) "Near-term" (cease operating by December 31, 2034, and adopt an annual capacity factor limit of 20 percent); (3) "Medium-term" (operate after December 31, 2031, but cease operating before January 1, 2040, *and* do not meet the definition of "Near-term"); and (4) "Long-term" (no commitment to cease operating before January 1, 2040).[96] For the Imminent- and Near-term subcategories, EPA is proposing to determine that BSER is routine methods of operation and maintenance, and the presumptively

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[93] *See* 88 Fed. Reg. at 33,343, 33,358.

[94] *See id.* at 33,360 tbl. 5.

[95] Proposed § 60.5880b (*Coal-fired steam generating unit* means an electric utility steam generating unit or IGCC unit that meets the definition of "fossil fuel-fired" and that burns coal for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, or that retains the capability to fire coal after December 31, 2029.").

[96] *See* 88 Fed. Reg. at 33,344.

approvable standard is an emission rate limit in lb CO_2/MWh-gross not to exceed the unit-specific baseline.[97] For the Near-term subcategory, EPA is proposing to require units to adopt a capacity factor limit of 20 percent beginning January 1, 2030.[98] For the Medium-term subcategory, EPA is proposing BSER to be 40 percent natural gas co-firing on a heat input basis. The presumptively approvable standard is a 16 percent reduction in the unit's annual baseline emission rate on a lb CO_2 per MWh-gross basis. Compliance would be required by January 1, 2030.[99] For the Long-term subcategory, EPA is proposing CCS with 90 percent CO_2 capture as BSER. The presumptively approvable standard is an 88.4 percent reduction in the unit's annual baseline emission rate on a lb CO_2 per MWh-gross basis. Compliance would be required by January 1, 2030.[100]

1. The Group recommends that EPA revise its proposed subcategories

The Group recommends that EPA revise its proposed subcategories to ensure grid reliability and to further stakeholder collaboration. First, the Group asks EPA to consider modifying the definition of the subcategories such that each subcategory would be based on the date that a unit *ceases to burn coal* rather than ceasing operation altogether. This would encourage owners/operators of coal-fired units to explore other options, such as converting to natural gas or biofuel, and provide them with greater flexibility as to how to meet reliability requirements and to best make use of existing infrastructure and the unit's remaining useful life. Identifying the subcategories based on a unit's cease-to-use-coal date rather than its retirement date is important to allow such units to continue to operate given concerns that transmission expansion will not be sufficient to support increasing renewables over the next several years and that continued reliance on fossil fuel-fired EGUs may be necessary.[101] BSER for units converting from coal to gas should be routine methods of operation and maintenance; relatedly, the proposed standards that would typically apply for existing gas-fired steam electric generating units should *not* apply while such conversion is occurring, and only apply after the gas conversion is complete.

EPA also should clarify that states should be able to take a planned fuel switch into account in setting the emission standard for a particular unit, based on the state's authority to consider remaining useful life and other factors ("RULOF") so that even if the unit is categorized as a Near-, Medium- or Long-term unit, the default requirements for those subcategories would not apply. And, at the least, EPA should make clear to the states that they have authority to establish alternative standards for units converting from coal to gas in the period before the conversion is completed.

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[97] *See id.* at 33,359.

[98] *See id.*

[99] *See id.*

[100] *See id.*

[101] *See* Jesse D. Jenkins et al., Princeton Univ. Zero Lab, *Climate Progress and the 117th Congress: The Impacts of the Inflation Reduction Act and Infrastructure Investment and Jobs Act* (July 2023) (discussing how failure to increase transmission expansion in the United States "severely" limits potential wind, solar and energy storage projects, and the rate of current transmission expansions would have to double to meet the Biden administration's net-zero target by 2035), https://repeatproject.org/docs/REPEAT_Climate_Progress_and_the_117th_Congress.pdf.

Second, the Group supports combining the Imminent-term and Near-term subcategories provided that the capacity factor limitation proposed for the Near-term subcategory would not apply prior to the end of 2032. It would be helpful for units that otherwise would be subject to the proposed Imminent-term subcategory to have the option for longer operation if such operation would be necessary for reliability purposes. Allowing continued operation past the end of 2032 subject to the capacity factor limitation would provide flexibility to the unit to continue providing support to the grid.

If EPA retains the proposed Imminent-term subcategory as a separate subcategory, EPA should extend the compliance date (*i.e.*, the cease-to-use-coal date as the Group requests) for this proposed subcategory to at least December 31, 2032, to align with the proposed retirement date in the Supplemental ELG proposal and to provide sources that will be imminently retiring or ceasing to use coal more lead time to coordinate with stakeholders and reliability authorities, as they will need to address replacement capacity needs.

Third, for the Imminent- and Near-term subcategories (or alternatively, the combined subcategory as the Class of '85 suggests), EPA should allow units that fall into such subcategories the option to comply with mass-based emission caps (*e.g.*, annual mass CO_2 limitations), and allow states to adopt such an approach. The mass-based approach would allow for more flexibility in operation and could help account for future operational variability—*i.e.*, make units less vulnerable to exceeding a static emissions rate limit. The Class of '85 recommends that the mass emissions cap or emissions rate limit be a longer-term average of at least annual (alternatively, a 12-month rolling) value. Owners/operators of affected EGUs should have the option to choose from a mass-based limit or a rate-based emissions limit.

Fourth, for the Near-term subcategory, a 20 percent capacity factor limit is too low to allow Near-term units to operate sufficiently to maintain grid reliability, and the Group urges EPA to establish a higher capacity limit, such as at least 33 percent (which would account for increased capacity during the summer months), to allow EGUs in this category sufficient operational flexibility to continue to support grid reliability. Similar to what has been recommended in terms of calculating whether an existing large stationary combustion turbine is frequently used (*see* Section V.A.1, *supra*), the Class of '85 recommends that EPA use a three-year average for calculating the average capacity factor instead of the proposed annual average. Moreover, in the event that an ISO, RTO, or other regional reliability authority calls for an emergency generation event, EPA should exclude the operating hours during the emergency event when calculating the average capacity for purposes of the capacity factor threshold.

EPA also needs to clarify the date by which units in the Imminent- and Near-term subcategories—for which BSER is routine methods of operation—must begin to meet the CO_2 emission rates assigned to them. The Proposal indicates that the standards must be met beginning in 2030, but that is not clear in the proposed regulatory text in the docket.[102] The Class of '85 instead recommends that the standards should be met beginning January 1, 2033, at the earliest, to preserve grid reliability and to align with the supplemental ELG proposal. Relatedly, the Group requests that the final rule allow for abbreviated treatment of any coal-fired units that will cease coal-fired operation prior to January 1, 2030. For such units, states could include in their state

[102] *See e.g.*, 88 Fed. Reg. at 33,371.

plans an enforceable requirement to such effect and exempt the units from any other interim reporting or compliance obligations.

Fifth, while EPA stated in its Additional Modeling Memo that "Coal-fired EGUs that convert entirely to burn natural gas are no longer subject to coal-fired EGU mitigation measures," and that the "Oil/Gas steam category includes coal to gas conversions,"[103] the regulatory text should make it clear to the states how such units should be treated for purposes of their plans. EPA also should clarify that the coal-fired EGU requirements would no longer apply even if a unit ceases use of coal at a date after January 1, 2030. In other words, states should have flexibility not to mandate a once-in, always in approach to the subcategories and their corresponding standards. Although the statement in the Additional Modeling Memo and other statements in the Proposal indicate that EPA believes such flexibility is available, EPA should make this clear in the final rule. Such flexibility would assist EGUs with developing cost-effective compliance options.

Lastly, for coal-fired steam generating units that co-fire natural gas, the Group asks EPA to clarify that the unit-specific annual emission rate baseline should be calculated based on the timeframe during which the unit was solely firing coal. The percent reduction required by each subcategory should then be based on that baseline.

2. EPA should reevaluate natural gas co-firing

For coal-fired units that are not already co-firing natural gas, in many cases the modification process would be significant. To illustrate, one of the Group's members expressed that for its circulating fluidized bed ("CFB") boilers, the highest amount the boiler could demonstrate was 36 percent co-firing with natural gas, which means the owner/operator would be forced to replace the entire technology (such as to corner-fired boilers). In many other cases, it would not be possible or cost effective to permit or construct gas pipeline infrastructure for the Medium-term subcategory. If EPA finalizes the 40 percent gas co-firing requirement for the Medium-term subcategory, the compliance deadlines should be extended by at least five years to accommodate required permitting, approval, and construction of required equipment and infrastructure.

The Group does not support a potential BSER based on low levels of natural gas co-firing for units in the Imminent- and Near-term subcategories because the technology is not feasible for units that do not have access to pipeline infrastructure. It also would not be possible or cost effective to permit and construct new pipeline infrastructure within the implementation timeline proposed by EPA for the Imminent- and Near-term subcategories. This should not be a basis for setting emissions limitations for units in the Imminent- and Near-term subcategories.

3. EPA should not set CCS as BSER for the long-term subcategory

For EGUs in the Long-term subcategory, EPA has established CCS as BSER, with a compliance deadline of January 1, 2030. For several reasons, the Group is concerned with EPA

[103] *See* Additional Modeling Memo at 3 n. c.

setting CCS as BSER for this subcategory. First, as discussed *supra* Section IV.A, the Group believes that EPA would exceed its statutory authority if the Agency required CCS as BSER.

Second, it would be nearly impossible for a prudent owner/operator of a Long-term unit to install and implement CCS by January 1, 2030, for reasons similar to what has been raised in Section V.B.1, *supra*. According to the Proposal, EPA expects the final emission guidelines will be published in June 2024, with a State plan submission deadline 24 months later and 14 months for EPA review and approval of the submitted state plans.[104]

According to the Agency, the planning, design, and construction of both the carbon capture system and the transport and storage system can be completed within five years.[105] That timeframe fails to match the proposed compliance deadline of January 1, 2030. A state plan submission deadline of 24 months, as proposed, would mean leaving less than three years after plan approval for detailed engineering, design, permitting, PSC approval, construction, and commissioning of required equipment and infrastructure, including any required pipelines and new transmission lines. EPA has failed to identify how its proposed timeline would work in practice. EPA cannot reasonably expect EGU owners/operators to begin expending material resources to plan, develop, and construct CCS before EPA has approved the state plan that specifies the scope of work and schedule.

Moreover, the Group is concerned that EPA may have severely underestimated the timeframe required to complete both systems given the factors involved. These factors include exploring and vetting of appropriate sequestration sites, procuring funding for operations and contractual arrangements, water availability and in turn the required additional authorization of water use, and land acquisition rights for a pipeline. Land acquisition rights may be particularly difficult where there is a patchwork of ownership. Pipeline infrastructure also must allow for safety, biological, and cultural assessments pursuant to, for instance, the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), Endangered Species Act ("ESA"), the National Historic Preservation Act ("NHPA"), and the National Environmental Policy Act ("NEPA") regulations. Such assessments can vary greatly in timing and may take years depending on the amount and type of resources impacted and public opposition.

More importantly, EPA should not require the construction of CCS until PHMSA finalizes safety standards for construction of CO_2 pipelines, which, according to the Spring 2023 Unified Agenda, will not even be *proposed* until January 2024.[106] Pipeline infrastructure development

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[104] *See* 88 Fed. Reg. at 33,372 ("The EPA expects that final emission guidelines will be published in June 2024 and is proposing a State plan submission deadline that is 24 months from publication which would be June 2026."). As further discussed *infra* Section V.H.1, the Group urges EPA to extend the submission deadline for state plans from 24 months to 36 months given the Proposal's breadth and complexity.

[105] *See id.*

[106] *See* U.S. Dep't of Transp., Pipeline & Hazardous Materials Safety Admin., *PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak* (May 26, 2022), https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures#:~:text=WASHINGTON%20%2D%20The%20U.S.%20Department%20of,protect%20communities%20from%20dangerous%20pipeline; *see also* Office of Mgmt. & Budget, *Pipeline Safety--Safety of Carbon Dioxide Pipelines*, RIN: 2137-AF60, Publication ID Spring 2023, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2137-AF60; 88 Fed. Reg. 48,598 (July 27, 2023).

extends far beyond the plant and must be built out across regions, which is estimated to total over 66,000 miles of pipeline.[107] Such development will require significant time to design, permit, and construct, particularly if pipelines are to be built in or near communities with EJ concerns. Electric generating companies are unlikely to be the pipeline operators, and the development of pipeline infrastructure likely is beyond the control of such companies as well.

Briefly stated, CCS projects require significant lead time and planning. CCS projects also require, among other complicated and time-consuming permits, a Class VI injection well permit for injecting CO_2 into the subsurface. Further, CCS projects would be dependent on the supply of available materials, equipment, and labor. Ultimately, EPA must be cognizant that the regulatory community affected by this Proposal own and operate *power plants*; the owners/operators are neither fuel producers, nor are they owners/operators of CO_2 pipelines and storage sites. Aside from the amine-based carbon capture projects that EPA identifies in the Proposal, which represent pilot-scale slipstream projects, the Group requests that EPA identify any other *actual*, non-pilot-scale projects in the United States that are still in operation and that have demonstrated the long-term ability to consistently capture 90 percent of total CO_2 emissions from an EGU.[108] In the Proposal, EPA cites to the Shady Point Plant as an example of achieved and available CCS.[109] However, the former Shady Point CCS facility is no longer in operation and, at the time of operations, was a small carbon capture unit treating a small slip stream of flue gas from the generating units.

Third, the Group is concerned that EPA has not adequately analyzed potential community concerns, which could delay or otherwise impede state or local permitting processes and approvals, or challenges to states seeking authorization for Class VI permitting, thereby leading to delays or failure to obtain necessary permits to accommodate CCS and likely resulting in cost increases. EPA also should issue rules or guidance related to plume migration of sequestered CO_2.

Fourth, if EPA finalizes CCS as BSER for the Long-term coal-fired steam generating unit subcategory, the Group requests that EPA account for the full landscape of permitting processes required to implement CCS, as well as the anticipated timeline thereof. Such permitting processes would include major or minor NSR or state permits that may require additional public notice.

Finally, although the Group does not agree with the Agency that CCS should be established as BSER at this time since it has not been adequately demonstrated, as discussed above in Section IV.A *supra*, if EPA nonetheless finalizes CCS as BSER in the final emission guidelines, the Group requests that EPA extend the compliance deadline (potentially with an additional extension period if an accompanying, legitimate justification is also provided). The extended compliance deadline would help ensure that all of the issues associated with installing CCS and the associated infrastructure have been more fully resolved. Alternatively, EPA should codify that states have authority to include in their plans additional time from the date that a state plan is approved by EPA before compliance must be demonstrated. Additionally, EPA should provide an emergency

[107] *See* Paul W. Parfomak, Cong. Rsch. Serv., IN11944, *Carbon Dioxide Pipelines: Safety Issues* (2022), https://crsreports.congress.gov/product/pdf/IN/IN11944.

[108] *See* 88 Fed. Reg. at 33,254.

[109] *See id.* at 33,392.

operation provision for a coal-fired unit to bypass CCS if it becomes non-functional and/or power demand is high.

G. Other Comments on the Proposed Emission Guidelines for Existing EGUs

1. Treatment of EGUs burning non-fossil fuels

The Proposal does not address how units burning biofuel are treated, although it appears that units firing solely biofuel would not be considered affected EGUs. The Group requests that EPA confirm that units exclusively firing or co-firing biofuel would be excluded from being an "affected EGU." It appears that EPA intends for such units to be excluded based on proposed § 60.5850b(e), which excludes "[n]on-fossil fuel units (*i.e.*, units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor)."

Excluding biofuel-fired units also would be consistent with the definition of "fossil fuel" in proposed § 60.5880b: "natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat." Non-"fossil fuel" would thus be any other material used for creating useful heat that is not derived from natural gas, petroleum, coal, or any form of solid fuel, liquid fuel, or gaseous fuel. The Class of '85 also recommends that renewable natural gas ("RNG") be considered a non-fossil fuel.

Despite these definitions, which appear to clearly exclude units solely combusting biofuel or other non-fossil fuel from being considered affected EGUs, EPA should confirm this in the final emission guidelines. The Group also requests that EPA provide confirmation that CO_2 emissions from biofuel or other non-fossil fuel are calculated as 0 lb/MMBtu when co-fired with fossil fuel.

Further, EPA should define "non-fossil fuel" so as to avoid the lack of clarity surrounding natural or certain synthetic fuels and whether units firing such fuel meet the proposed § 60.5850b(e) exemption from being an affected EGU. The Group proposes that EPA adopt the following definition of "non-fossil fuel" in proposed § 60.5880b:

> *Non-fossil fuel* means any fuel derived from material for the purpose of creating useful heat that is not a *fossil fuel* and includes, but is not limited to, woody and non-woody biofuel, landfill gas (including any alternatives and renewable natural gas), and municipal solid waste or a synthetic fuel such as synthetic natural gas or electrofuels that have a carbon intensity of 0.45 kg CO_2/kg product produced.

2. Net energy output for combined heat and power facilities

The Group recommends that EPA modify the definition of "net energy output" for combined heat and power ("CHP") facilities in proposed § 60.5880b. EPA should clarify that the CHP facility supplying either thermal or electric/mechanical power or energy to a steam and/or hot water client is able to subtract the supplied total annual thermal or electric output from the gross electric sales generated by the facility.

H. State Plans for Emission Guidelines

Section 111(d) of the CAA requires states to submit plans that establish standards of performance that are at least as stringent as EPA's emission guidelines. The state plans must include provisions for the implementation and enforcement of these standards, as well as compliance deadlines and increments of progress for such sources. The Proposal would require the state plans submitted pursuant to Section 111(d) to be submitted to EPA within 24 months of the effective date of the emission guidelines, with EPA developing a federal plan for the state if the state does not submit one.[110] The Proposal indicates that state plans must include compliance deadlines for existing steam generating units of no later than January 1, 2030, and for existing combustion turbines of no later than January 1, 2032, or January 1, 2035, depending on which BSER pathway they select.[111] The state plans also must use EPA's proposed methodologies in establishing presumptively approvable standards of performance for most types of affected EGUs, apply EPA's framework for establishing a less stringent standard based on a facility's RULOF, or if necessary, demonstrate to EPA that a facility cannot reasonably achieve the standard through application of BSER.[112] Additionally, the state plans must allow for compliance flexibilities and trading.[113]

The Proposal would have significant impacts on EGU fleets across the United States. If the Proposal is finalized, Subpart UUUUb would result in large numbers of EGUs retiring or implementing modifications on a compressed and concurrent timeframe, which likely would affect grid reliability during that timeframe. Accordingly, states should be allowed to provide EGUs the flexibility to change subcategories under CAA Section 111(d) and should not impose a "once in, always in" approach. This flexibility is important given the uncertainty of availability of federal funding incentives such as the extension of credits under the IRA. EPA also should make it clear that states have the authority to determine how requirements affecting subcategorization are made enforceable (*i.e.*, what the state will require for an election to commit and enter into an enforceable commitment).

1. EPA should provide more time for states to develop and submit their plans

States should be provided at least 36 months to submit plans for EPA's approval, rather than the 24 months currently proposed. As a starting matter, the breadth, complexity, and novelty of the Proposal makes a two-year window far too short. This is especially true given that states operate with far fewer resources compared to the federal government, making the development of regulatory programs inherently more difficult. Additionally, to the extent the final rule establishes CCS as BSER, the Group's discussion in Section V.B.1, *supra*, further demonstrates that, in the context of CCS, the complicated nature of this technology and all the regulatory landscape affecting it would make a 24-month state plan submission window unworkable.

[110] *See id.* at 33,406.

[111] *See id*. at 33,403.

[112] *See id.* at 33,398.

[113] *See id.* at 33,393.

Companies also will need time to engage with their respective public utility commissions to determine what course of action would have the least impact on grid reliability and electricity costs to customers, including whether to install controls, which could require extended outages for installation, or whether to seek early retirement and the development or purchase of replacement generation. This planning would need to occur before states can submit their plans to EPA.

2. EPA should provide more compliance flexibilities and develop model emissions averaging rules and trading programs

The Class of '85 supports providing states flexibility to use mass-based trading or averaging wherein multiple affected EGUs may trade or average between the units to achieve an overall approved emissions limit equivalent to what BSER would achieve. This is consistent with prior rulemakings, where EPA authorized trading and averaging programs as compliance methods in other emission guidelines.[114] The Group further supports state plans incorporating averaging and emission trading, but the Group recommends that EPA develop and provide states with models or templates of such mechanisms so that states can use them in their planning process. Such models or templates would be helpful given that, based on the Proposal, states would have only 24 months from the effective date of the final rule to develop and submit a plan to EPA (*see* discussion in Section V.H.1, *supra*, that states should be provided at least 36 months to submit state plans). Models/templates would help states with engaging in meaningful outreach and engagement to ensure that pertinent stakeholders are included in the development of their plans, which may require additional enhancements to states' current public outreach processes. Models/templates also would provide states with insight into the type of plan that would be approvable. Among other mechanisms, EPA should develop a model emissions-averaging rule for states to adopt (at their discretion) by reference into their state plans. For instance, EPA could develop a model averaging plan similar to the Acid Rain Program's NOx averaging program, which could be converted into a template for regulating CO_2, and where:

- Emissions limits for the EGUs in the averaging plan would be determined by the states using the process outlined by EPA and appropriately applying RULOF;
- Any emissions limit also should account for unit degradation over time;
- The model rule would use the same formulas as the Acid Rain Program NOx averaging plans, with CO_2 substituted for NOx;
- All EGUs included in an averaging plan would need to have a common designated representative, as identified for the Acid Rain Program and the Cross-State Air Pollution Rule ("CSAPR"), or a company-specific designated representative;
- Averaging across states should be allowed for EGUs where there is common ownership and a common designated representative;

[114] *See id.* at 33,392 nn. 658, 659.

- Averaging plans would be established for a multi-year period but could be revised as frequently as annually depending upon a company's needs;

- GHG emissions intensity could be calculated such that emissions figures could be reduced when using alternative lower GHG fuels, such as what is offered in California's Low Carbon Fuel Standard;

- Multiple types of existing EGUs (*e.g.*, coal, gas-fired steam electric units, and stationary combustion turbines) could be included in the same averaging plan; and

- Ensuring the emission standards are met would consist of comparing an averaging plan's actual performance against the required performance using the state-approved emission standards that otherwise would apply.

EPA should address whether state or regional GHG emission reduction programs would qualify for compliance with proposed Subpart UUUUb or what revisions to the programs would need to be made for the participating states to show that their programs are equivalent to the GHG emission standards. For example, the Regional Greenhouse Gas Initiative ("RGGI") is an established program that has been successful in reducing CO_2 emissions. Participating states should be encouraged to continue using it to drive CO_2 emissions reductions, and EGUs in those states should not be forced into a new compliance regime. In addition to RGGI, other states have mass-based emissions reduction programs, such as the California and Washington cap-and-trade programs, and Oregon's Clean Electricity Law HB 2021.[115] EPA should provide clarity to the states regarding how such programs can serve as channels for meeting the proposed Section 111(d) requirements, instead of requiring separate reductions via the proposed Subpart UUUUb standards.

EPA also should allow states to include the option for a cap-and-trade program and develop and provide a model trading rule that could be adopted by states. With only 24 months to develop a state plan, states are unlikely to have sufficient time to develop their own individual cap-and-trade programs. A model rule that a state could tailor as appropriate to the circumstances in the state would encourage the adoption of such plans and help ensure timely submittal of state plans to EPA for approval. Additionally, EPA should permit states to provide companies with CO_2 credit (via a trading program) for overcompliance and early actions and provide flexibility for CAA Section 111(b) units to opt into averaging or trading plans, such as a fleetwide averaging compliance plan.

Further, EPA should not restrict certain subcategories from complying with the standards of performance through trading. According to the Agency:

> The specific subcategories proposed under these emission guidelines for steam generating units are designed to provide for much of the same operational flexibility as would be provided through trading; as a result, the EPA believes that it would not be appropriate to allow affected EGUs in certain subcategories—imminent-

[115] *See, e.g.*, Clean Electricity Law, HB 2021 (Or. 2021) (requiring investor-owned utilities to reduce the GHG emissions associated with serving retail customers in Oregon from a 2010-2012 average baseline by 80% by 2030, 90% by 2035, and 100% by 2040).

> term and near-term coal-fired steam generating units and natural gas- and oil-fired steam generating units—to comply with their standards of performance through trading.[116]

It is unclear how the proposed subcategories provide the same operational flexibility as would be provided through trading. Trading would, in fact, incentivize certain affected sources to reduce their emissions more than necessary so that they could sell or bank surplus allowances and provide other affected sources greater flexibility to achieve compliance.[117] For the same reason, EPA should not restrict affected EGUs with less-stringent, source-specific standards based on RULOF from complying with those standards through trading.[118] GHG emissions are a global issue; therefore, EPA should not force states to focus exclusively on unit-level compliance for sources in the Imminent- and Near-term categories or for gas-and oil-fired steam generating units where trading or averaging between a wide array of EGUs would achieve the same GHG reductions.

Finally, in the spirit of encouraging more compliance flexibilities, EPA should not prevent states from experimenting with new technologies. Ultimately, the BSER imposed by the Proposal forces companies to "pick a lane" on technologies, which, in some cases, may be impossible or infeasible. Better technologies (or strategies) that have not yet emerged should not be precluded/prohibited due to polices set by EPA. And the best way to prevent such entrenchment and/or the incentive to merely follow the path of least resistance would be to maximize the flexibility afforded to states in setting their emission guidelines. After all, the states would be in the best position to understand what the local needs and the correspondingly appropriate control technology would be.

3. EPA should permit mass-based limits in state plans

EPA should allow states the option of setting mass-based limits (total tons of CO_2) as a compliance option in addition to establishing rate-based limits (lbs CO_2 per MWh). EPA's Proposal already provides for the use of mass emissions to calculate an emissions rate and refers generally to mass-based trading. However, a mass-based approach to compliance is valuable regardless of whether the state implements a trading mechanism. At its simplest, a mass-based approach would require affected EGUs to meet an absolute emissions limit (equivalent to the emissions level achieved by the adopted BSER in a given year).

A mass-based compliance approach would support reliability without eroding the environmental outcome EPA seeks. Mass-based emissions regulation recognizes that GHG are not a locally harmful air pollutant, but a global one. Compliance based on mass emissions from an EGU provides operators flexibility to run the unit when it is most needed for reliability, rather than chasing an emissions rate throughout the year. Process changes implemented at EGUs that achieve reductions in excess of BSER could serve as the primary energy source, enabling units

[116] 88 Fed. Reg. at 33,393.

[117] *See* EPA, *How Do Emissions Trading Programs Work?* (last visited July 20, 2023), https://www.epa.gov/emissions-trading-resources/how-do-emissions-trading-programs-work.

[118] *See* 88 Fed. Reg. at 33,394.

that do not meet BSER to serve when they are needed for reliability. Such an approach would allow owners/operators to focus on carbon reduction efforts where they are the most effective.

4. EPA should provide further guidance and flexibility with respect to EGUs that are committing to retire

The Group requests that EPA clarify or provide more guidance to states as to what steps units must take to "commit" to a retirement date or cease-to-use-coal date to fall into an applicable subcategory. Specifically, EPA should clarify that states have authority to determine what that commitment needs to be, whether via a Title V permit provision or through an administrative order with the state.

States also should have the authority to determine when such commitments need to be finalized and federally enforceable. Provided that such commitment will be finalized and federally enforceable before January 1, 2030, states should be able to include a future commitment in their plans. Specifically, according to the Proposal, an EGU is considered a coal-fired steam electric generating unit if it (1) meets the definition of "fossil fuel-fired" *and* (2) meets one of the following: (a) burns coal for more than 10.0 percent of the average annual heat input during the three calendar years prior to January 1, 2030, or (b) for more than 15.0 percent of the annual heat input during any one of those calendar years, or (c) retains the capability to fire coal after December 31, 2029.[119] Given that state plans are likely to be due in 2026, a state (or an electric generating company) may not necessarily know whether a unit will remain coal-fired for the entire 2027–29 timeframe. A unit that is currently coal-fired may choose to take a permit limit by December 31, 2029, that will exclude it from the coal-fired definition. The state should not be forced to require such a unit to have that permit limit in place *before* the state submits its plan to EPA. Instead, the state should have complete authority to determine what assurances it needs from EGUs to appropriately categorize them in its plan, and EPA should clarify that in Subpart UUUUb.

5. EPA should make it clear that states have broad flexibility in their RULOF evaluations

EPA should make it clear that Section 111(d) delegates broad authority to states to address reliability and affordability concerns under the RULOF provision included in the CAA. Additionally, EPA should clarify that states have the authority to adjust unit-specific time frames and operational constraints under RULOF evaluations and adjust such requirements and emissions standards as appropriate. Ultimately, the pace and timing of transitioning fossil fuel-fired generation to support a low-carbon economy must account for multiple factors. In particular, the timing of some Group members' plans to retire generation assets, as well as to construct cleaner energy resources, are subject to formal review processes and approvals by regulators, including state utilities boards and public service commissions and RTOs/ISOs. For instance, RULOF options should allow states to consider ozone nonattainment when making decisions on whether to require switching to hydrogen or allow states to use processes such as the Midcontinent Independent System Operator's ("MISO's") accredited capacity from the Resource Adequacy Process up until the unit's retirement date—rather than a 20 percent capacity factor limitation—to

[119] *See* proposed § 60.5880b.

ensure reliability and to consider seasonal construct (*i.e.*, better integration with renewables/storage).[120]

Moreover, the Proposal appears to incorporate the proposed provisions regarding RULOF in EPA's December 2022 proposed rulemaking.[121] The December 2022 rulemaking has not been finalized, and EPA cannot adopt the RULOF provisions via this Proposal without first finalizing the December 2022 rulemaking. The Group opposed aspects of the December 2022 rulemaking and hereby incorporates its comments on RULOF from the December 2022 rulemaking.[122] To the extent that EPA finalizes the RULOF provisions as proposed in the December 2022 rulemaking, for purposes of Subpart UUUUb, the Group urges EPA to adopt the revisions to RULOF the Class of '85 recommended in its comments on the December 2022 rulemaking.

6. EPA should not be overly prescriptive as to the requirements states must include in their plans regarding increments of progress

For Long- and Medium-term existing coal-fired steam generating units, stationary combustion turbines selecting the CCS pathway, and stationary combustion turbines selecting the low-GHG hydrogen pathway, the Proposal requires state plans to establish increments of progress with calendar-date deadlines pursuant to proposed § 60.6740b(a)(4). Such increments of progress include submittal of a final control plan to the state, completion of awarding appropriate contracts, initiation and completion of on-site construction or installation of emission control equipment or process change, commencement of permitting actions relating to pipeline construction, and the final compliance date.[123] The state plans also must establish legally enforceable milestones pursuant to proposed § 60.5740b(a)(5) for EGUs that elect to cease operations.[124]

The Group requests that EPA avoid establishing proscriptive, legally-enforceable milestones that states must include in their state plans. Specifically, EPA should not mandate that states include in their plans the detailed milestone requirements identified in the Proposal, which would limit key compliance flexibility that EGUs will need with respect to the final Section 111(d) standards and would unnecessarily open new enforcement avenues.

The milestone requirements are particularly onerous for EGUs that elect to retire, or convert, refuel, or repower. According to the Proposal, such requirements include: (1) providing notice to the official reliability authority of the federally-enforceable retirement date; (2) submitting an official suspension filing; (3) submitting an official retirement filing; (4) providing a comparison of how the key milestone dates compare with similar units in the state that have permanently ceased operation within the past 10 years; and (5) providing supporting

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[120] For additional context, MISO proposed this seasonal resource adequacy construct to address significant increases in emergency events that occur year-round, driven by factors including generation retirements, reliance on intermittent resources, outages resulting from extreme weather events, and declining excess reserve margin. This measure has been recently approved by FERC. *See* FERC, 182 FERC ¶ 61,096 (Feb. 16, 2023), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230216-3085&optimized=false.

[121] *See* Proposed Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), 87 Fed. Reg. 79,176 (Dec. 23, 2022).

[122] Dkt. ID No. EPA-HQ-OAR-2021-0527-0093 (posted Feb. 28, 2023) (Attachment C).

[123] *See* 88 Fed. Reg. at 33,388.

[124] *See id.* at 33,390.

regulatory documents. In each year prior to permanently ceasing operations, the EGU would have to provide the state with annual Milestone Status Reports, and then a Final Milestone Status Report within six months after permanently ceasing operations.[125]

CAA Section 111 is concerned with regulating emissions and not with the process of closing an EGU. Pursuant to the statutory intent and scope of Section 111, all that EPA can and should require is an enforceable commitment to shut down or switch fuels. Forcing fuel choices or compelling energy production in a particular manner is outside of EPA's purview under the CAA. Certain documentation requirements EPA has proposed may otherwise be required by the state regulatory authority. That, however, is a separate matter, and it is administratively burdensome and a waste of resources for companies to have to devote time to preparing such documentation that otherwise may not be required and then including such documentation on a website that the companies must set up and manage.

For example, EPA has offered no justification for companies to provide a comparison of how its key milestone dates for retirement compare with similar units in the state that have permanently ceased operation within the past 10 years. This is a completely unnecessary requirement that would force companies to expend significant resources to fulfill. Whether other EGUs in the state were on a slower or faster path to retirement based on their particular circumstances and reliability considerations at that time, particularly over a 10-year period, has no bearing on a company's determination of the appropriate key milestone dates for its particular EGU to retire as a compliance pathway for Section 111(d).

Existing enforcement mechanisms can effectively address attempts to circumvent the shutdown date. There is no need or basis for EPA to require detailed facility closure plans of units or for there to be added enforceable interim deadlines. Decommissioning of power plants, following the shutting down of electric generating operations, needs to be a flexible process, as it hinges on contractor availability and may be impacted by unforeseen circumstances, such that it does not make sense for detailed closure plans to be enshrined in a state plan.

7. EPA should not require companies to develop a website and publish information related to compliance with section 111(d) standards

Under Proposed Subpart UUUUb, state plans must require EGUs to establish a publicly accessible "Carbon Pollution Standards for EGUs Website" to post all relevant documents, including documents required by the applicable increments of progress, as well as compliance information.[126] EPA should eliminate this state plan requirement. Companies already extensively report GHG emissions data under the Acid Rain Program and Mandatory GHG Reporting Program. The public can access the data via existing EPA tools, and it is not necessary to create additional data repositories. Title V operating permits also require similar information on what would be required for the proposed website, and the Title V information already is publicly available. And, any significant investments and retirement plans are typically available from other public sources, such as regulatory filings on public utility commission websites and financial submittals to the Securities and Exchange Commission (*e.g.*, Forms 10-K, 10-Q). States should

[125] *See id*.

[126] *See id.* at 33,400.

have the opportunity to decide how, and to what extent, information related to compliance with the Section 111(d) standards should be publicly available, and EPA should not automatically impose such a burden on the regulated community.

Mandating development of such a website would force companies to assign staff, not only to maintain the website but also to ensure the timely posting of required information. In addition, it would create yet another potential opportunity for a compliance violation if the website were down and the deadline for posting information could not be met. EPA should be seeking ways to streamline the compliance burden, not adding another duplicative layer of reporting that would have no effect on emissions. The increments of progress that states must include in their plans should provide sufficient flexibility to allow for unanticipated developments, and requiring companies to provide such information publicly makes it more difficult for them to seek compliance flexibilities if needed, without potentially triggering challenges or litigation by the public if progress cannot be timely met due to unanticipated developments. Publicly posting certain information also may present a security risk or confidentiality concerns with respect to critical infrastructure.

8. EPA should provide safety valves to ensure that companies are not held liable for failing to meet deadlines based on factors beyond their control

Companies should not be held liable or responsible for processes they cannot control, such as their ability to obtain land rights, federal permitting, etc., and it is essential that EPA provide reliability "safety valves," especially for situations where grid reliability could be threatened by compliance requirements that cannot be met for reasons beyond the regulated entities' control. The Group also requests that EPA provide a mechanism to allow companies to seek an extension or exemption from the proscriptive deadlines (on a case-by-case basis) if external factors prevent a company from complying with the deadlines or if FERC or other similar reliability authorities (*e.g.*, RTO, ISO, regional reliability authorities) deem a unit essential for maintaining grid reliability. The proscriptive deadlines may not be achievable due to long lead times for applicable permitting processes, as well as for the planning, permitting, construction, and operation of supporting infrastructure (*e.g.*, transmission lines and pipelines for natural gas, hydrogen, or CCS).[127] The deadlines also might not be achievable as companies would be dependent on the availability of equipment and labor to complete the upgrades.

Under CAA Section 113, EPA has the "discretion to agree to negotiated resolutions, including administrative compliance orders ("ACOs") for achieving compliance with CAA requirements that include expeditious compliance schedules with enforceable compliance milestones."[128] EPA is proposing that ACOs could be used for an affected EGU that is required to run for reliability purposes in violation of a State plan requirement. EPA proposes that such requests would be evaluated on a case-by-case basis but notes that "as a general matter, the EPA anticipated that to qualify for an ACO, the owner/operator would need to demonstrate, as a

[127] MISO, Attachment Y to the MISO Outage Operations Business Practice Manual, Notice for Process for Retirement, BPM-008-r-29, at 80 (discussing an approximately one-year advance notice requirement, in which MISO conducts studies on a quarterly basis and then has 150 days from commencing the study to notify the EGU owner), *approved by* FERC, Order (Feb. 10, 2023), Dkt No. ER23-630-000.

[128] 88 Fed. Reg. at 33,401.

minimum, that certain conditions have been satisfied."[129] These conditions include: (1) requesting, in writing and in a timely manner, an enforceable compliance schedule in an ACO; (2) providing EPA written analysis and documentation of reliability risk if the unit were not in operation; (3) providing EPA with written concurrence with the reliability analysis from the relevant electric planning authority; and (4) demonstrating that there is insufficient time to address the reliability risk and potential noncompliance through a State plan revision.[130]

The Group urges EPA to reconsider using ACOs to provide meaningful assurance to sources to protect grid reliability for unanticipated factors beyond an owner or operators' control. ACOs are ill-suited to addressing reliability issues for several reasons. ACOs would be offered only after the fact to resolve any alleged violations and would not help a company that needs to decide in the moment whether to keep running and risk violation or shut down and risk the grid. Also, ACOs carry negative implications and the potential for significant civil penalties. Additionally, ACOs are typically intended to resolve relatively short-term noncompliance events that can be readily remedied and that do not reflect a fundamental inability to comply. As such, ACOs are ill-suited for addressing the long-term challenges associated with meeting the proposed standards or for protecting against injunctive relief.

VI. COMMENTS ON PROPOSED NEW SOURCE PERFORMANCE STANDARDS FOR FOSSIL FUEL-FIRED STATIONARY COMBUSTION TURBINES

The Group supports EPA's proposal not to revise the 2015 NSPS standards in 40 C.F.R. Subpart TTTT for fossil fuel-fired steam generating units.[131] However, as discussed below, the Group has concerns with several aspects of the proposed revisions to the NSPS for stationary combustion turbines, which would be codified in a new Subpart TTTTa.

A. The Group Recommends that EPA Revise Its Proposal for New Fossil Fuel-Fired Stationary Combustion Turbines

1. EPA should revise the low-load subcategory

The Proposal subcategorizes new and reconstructed fossil fuel-fired stationary combustion turbines by load level. Low-load units are defined as those supplying 20 percent or less of their potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.[132] For Low-load stationary combustion turbines, EPA is proposing use of lower emitting fuels (*e.g.*, natural gas and distillate oil) as BSER. The emission limit would be set at a range between 120 to 160 lb CO_2/MMBtu, depending on the type of fuel combusted.[133]

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[129] *Id.*

[130] *Id.*

[131] *See id.* at 33,243. The Proposal appears to largely leave the 2015 NSPS emission limits for fossil fuel-fired steam generating units intact, aside from certain changes to the proposed regulatory text for Subpart TTTT, such as adding that the grace period data is invalid for compliance, which the Group opposes (*see* Section VII, *infra*).

[132] *See id.* at 33,322 (Table 2).

[133] *See id.*

For the Low-load category, the Group recommends that EPA define "low" as supplying 25 percent (rather than 20 percent) or less of its potential electric output net-electric sales on either (rather than both) a 12-month operating period or a 3-year rolling averaging basis. The Group supports the BSER for low-load peaking units being the use of "lower emitting fuels," as EPA appropriately adopted this standard in the 2015 NSPS for non-base load units and continuing with this standard allows for the use of dispatchable, flexible resources to be included in the mix. The Group, however, asks that EPA provide clarification on RNG and whether it is considered a "lower emitting fuel."[134] EPA does not distinguish between RNG and regular natural gas in defining "lower emitting fuel." However, while the proposed definition of "natural gas" in proposed Subpart UUUUb does not include RNG, EPA noted that, if these gasses are processed and mixed into the pipeline network, "it is the intent that this mixture be considered natural gas for the purposes of 40 CFR part 60, subpart TTTT and the proposed 40 CFR part 60, subpart TTTTa."[135]

2. EPA should reevaluate BSER for the intermediate- and base-load subcategories

EPA is proposing to define Intermediate-load stationary combustion turbines as those that supply greater than 20 percent of their potential electric output and their design efficiency times their potential electric output or less as net-electric sales on both a 12-operating month and a 3-year rolling average basis, with Base-load stationary combustion turbines defined as those supplying more than their design efficiency times their potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.[136] For both of these subcategories, EPA is proposing an approach in which the BSER has two components: (1) highly efficient generation, and (2) depending on the subcategory, use of CCS or co-firing low-GHG hydrogen. These components would take effect across three phases.

During Phase 1, Intermediate- and Base-load stationary combustion turbines would meet a standard of performance based on highly efficient generation (*i.e.*, most efficient available turbine) by the date the final rule is promulgated or upon initial start-up of the facility, whichever is later.[137] For Intermediate-load, the emission limit would be 1,150 lb CO_2/MWH-gross.[138] For Base-load, the emission limit would be 770 lb CO_2/MWh-gross for larger stationary combustion turbines (baseload rating of 2,000 MMBtu/h or more), and a range of 770 lb CO_2/MWh-gross to 900 lb CO_2/MWh-gross for smaller Base-load stationary combustion turbines (base load rating less than 2,000 MMBtu/h) depending on the specific base load rating of the unit.[139]

During Phase 2 and 3, stationary combustion turbines in the Intermediate- and Base-load subcategories also would meet more stringent standards of performance at specified compliance deadlines. Intermediate-load stationary combustion turbines would meet the Phase 2 standard based on 30 percent by volume low-GHG hydrogen co-firing beginning January 1, 2032. The

[134] As discussed in Section V.G.1, *supra*, the Class of '85 requests that EPA include RNG in a definition of non-fossil fuel.

[135] *Id.* at 33,333.

[136] *See id.* at 33,322 (Table 2).

[137] *See id.*

[138] *See id.*

[139] *See id.* at 33,244, 33,322; *see also* proposed Table 1 of Subpart TTTTa.

emission limit would be set at a 12-operating month average range between 1,000 to 1,290 lb CO_2/MWh of gross energy output.[140] Base-load stationary combustion turbines would have two pathways: CCS, or low-GHG hydrogen co-firing. For CCS, the Phase 2 standard would be based on 90 percent capture of CO_2 using CCS beginning January 1, 2035. The emission limit would be set at a 12-operating month average range between 90 to 130 lb CO_2/MWh-gross.[141] For low-GHG hydrogen co-firing, the Phase 2 standard would be based on co-firing 30 percent by volume low-GHG hydrogen beginning January 1, 2032.[142] The emission limit would be set at a 12-operating month average range between 680 to 1,100 lb CO_2/MWh-gross.[143] Stationary combustion turbines on the low-GHG hydrogen pathway also would meet a Phase 3 standard based on co-firing 96 percent by volume low-GHG hydrogen beginning January 1, 2038.[144] The emission limit would be set at a 12-operating month average range between 90 to 130 lb CO_2/MWh-gross.[145]

The Group is concerned that the proposed CO_2 limits for Intermediate and Base-load stationary combustion turbines are so stringent that companies will be disincentivized from building new units. Coupled with the proposed limits on capacity factors in various EGU subcategories, the Group is concerned as to how grid reliability and electricity affordability can be maintained. The Group recommends that, for the Intermediate-load category, EPA define "intermediate" as having a capacity factor greater than 25 percent. The Group also recommends that NGCCs be allowed to operate at higher capacity factors without being subject to CCS-based or hydrogen-based emission standards. EPA also should make it clear that EGUs have the flexibility to change subcategories under CAA Section 111(b).

Further, EPA should not establish CCS as Phase 2 BSER for units in the Base-load subcategory (*see* Section IV.A on legal arguments regarding BSER and Section V.B.1 on the technical and permitting challenges associated with CCS). On top of the concerns already raised by the Group, the proposed BSER of CCS would substantially increase the costs associated with constructing a new gas-fired stationary combustion turbine facility, potentially making many such projects uneconomical. Likewise, low-GHG hydrogen co-firing also should not be BSER in Phase 2 and 3 for units in the Intermediate- and Base-load subcategories (*see* Section IV.A. on legal arguments regarding BSER and Section V.B.2 on the technical challenges associated with low-GHG hydrogen co-firing). In addition, EPA must address: (1) how EPA determined that original equipment manufacturers ("OEMs") will have equipment available to support the goal of 96 percent low-GHG hydrogen combustion rates—specifically, with respect to stationary combustion turbines being sold today to support 2038 in service dates; (2) whether the vendor will provide contractual commercial guarantees; and (3) whether the equipment vendors will guarantee the heat rates for the new units. It also appears that EPA set the 30 percent low GHG-hydrogen co-firing

[140] *See id.*

[141] *See id*. at 33,324–26.

[142] *See id.*

[143] *See id.*

[144] *See id.*

[145] *See id.*

value solely on what is required to achieve a 12 percent reduction in CO_2 emissions rather than what is feasible.[146]

Lastly, the Group recommends that EPA provide flexibility for Section 111(b) units to opt into state plans for existing EGUs, such as in a fleetwide averaging compliance plan. The Group also recommends that electricity sold during an emergency—regardless of whether the unit is already operating or not—should not count towards the percentage electric sales subcategorization threshold.[147] Any available unit that an RTO/ISO (or other regional reliability authority) needs to operate during an emergency is essential for providing flexibility, maintaining system reliability, and minimizing overall costs to the sector,[148] and a unit should not be penalized for such operation by becoming subject to a stricter standard.

B. The Group Supports EPA's Proposal Regarding New Fossil Fuel-Fired Stationary Combustion Turbines in Non-Continental Areas

The Group supports EPA's proposal to exclude EGUs not connected to sources of natural gas, such as those located in Hawaii, from proposed Subpart TTTTa and Subpart TTTT.[149] Such EGUs should be exempted due to geographic isolation. One Group member's system, which is based in Hawaii, is not connected to the grids on other Hawaiian Islands due to its location in the middle of the Pacific Ocean. As a result of its isolated nature, the Group member's system is different from electric generating systems in the contiguous 48 states in several significant respects, including limited fuel choices as neither natural gas nor liquified natural gas is available in sufficient quantities.

VII. CLARIFICATION ON VARIOUS ASPECTS OF THE PROPOSED REGULATORY TEXT

The Group requests that EPA provide clarification regarding certain aspects of the proposed regulatory text. First, per proposed § 60.5540a(a)(2)(iv)(2), EPA is proposing to exclude operating hours in which "[g]race periods for delaying RATAs [relative accuracy test audits] for any of the parameters used to determine the hourly carbon dioxide mass emissions, or if a heat input-based standard applies, for any parameters used to determine the hourly heat input." The Group opposes this revision and requests that EPA explain why it is no longer allowing "grace period" data, as such periods are typically used to prevent forcing a unit to operate when it is otherwise offline just to complete RATA testing. Accordingly, grace periods prevent unnecessary emissions, and companies should not be penalized under the NSPS for taking advantage of grace periods to delay RATAs. It also is not clear how this exclusion would work in practice given that data reported to the Clean Air Markets Division includes data reported during grace periods.

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[146] *See id.* at 33,325.

[147] *See id.* at 33,333 n. 515.

[148] *See id.*

[149] *See* proposed § 60.5509(a)(8) (exempting stationary combustion turbines that are "not capable of combusting natural gas (*e.g.*, not connected to a natural gas pipeline)").

Second, proposed § 60.5740b references § 60.5745b, but the referenced section does not exist in the proposed regulatory text.

Third, per proposed § 60.5535(b)(5)(iii), the result from paragraph (b)(5)(ii) incorrectly requires amounts to be multiplied by 909.1 to convert from tons of CO_2 to kg of CO_2.[150] It is unclear why proposed § 60.5535(b)(5)(iii) incorrectly references 909.1. The correct conversion factor is 907.185. The Group requests that EPA update 909.1 to 907.185, as EPA's proposed number would result in overreporting.

VIII. CONCLUSION

The Class of '85 Regulatory Response Group appreciates the opportunity to submit comments on the Proposal. The Group asks EPA to consider the recommendations above considering the significant impacts that the proposed Section 111(b) and (d) standards would have on how Group members balance their responsibility to provide reliable and affordable electricity and their obligations to transition to renewable energy generation.

Dated: August 8, 2023

Respectfully submitted,

The Class of '85 Regulatory Response Group
contact@class-of-85.com

[150] *See also* proposed § 60.5535(c)(3).

Attachment A

List of Class of ’85 members supporting these comments

List of Signatories

AES Corporation
Alliant Energy Corporation
Ameren
Arizona Public Service
Arizona Electric Power Cooperative, Inc.
Arkansas Electric Cooperative Corporation
Basin Electric Power Cooperative
City of Tallahassee
Cogentrix Energy Power Management, LLC
Dairyland Power Cooperative
Dayton Power & Light Company
Dominion Energy
Duke Energy
Entergy Services, LLC
Evergy, Inc.
Florida Municipal Electric Association
Gainesville Regional Utilities
Great River Energy
Hawaiian Electric Company, Inc.
Indianapolis Power & Light Company
JEA
Lakeland Electric
Louisville Gas & Electric/Kentucky Utilities
Minnesota Power
NRG Energy
OGE Energy Corp.
Orlando Utilities Commission
PowerSouth Energy Cooperative
Public Service Company of New Mexico
Rainbow Energy Center, LLC
Salt River Project
Talen Energy
Tucson Electric Power Company
Western Farmers Electric Cooperative
Xcel Energy Inc.

Attachment B

Class of ’85 comments on EPA’s non-rulemaking docket

Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units

Dkt ID. No. EPA-HQ-OAR-2022-0723-0037

COMMENTS OF THE CLASS OF '85 REGULATORY RESPONSE GROUP ON EPA'S NON-RULEMAKING DOCKET ON REDUCING GREENHOUSE GAS EMISSIONS FROM NEW AND EXISTING FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS

Docket No. EPA-HQ-OAR-2022-0723

I. INTRODUCTION

On September 1, 2022, EPA's Office of Air Quality Planning and Standards issued a memorandum announcing the opening of a non-rulemaking docket for public input on EPA's efforts to reduce emissions of greenhouse gases ("GHGs") from new and existing fossil fuel-fired electric generating units ("EGUs").[1] According to the Agency, the goal of the non-rulemaking docket is to gather perspectives from a broad group of stakeholders.

The Class of '85 Regulatory Response Group ("Class of '85" or "Group") respectfully submits these comments to the non-rulemaking docket.[2] The Class of '85 is a voluntary, ad hoc coalition of over 40 electric generating companies from across the country that has been actively involved in the development and implementation of Clean Air Act ("CAA") rules affecting the electric generating industry for over 30 years, including the regulation of GHG emissions from new and existing EGUs. The Group has a particular interest in EPA's efforts to reduce GHG emissions from new and existing fossil fuel-fired EGUs and the use of information collected in the non-regulatory docket in any future CAA Section 111(b) and Section 111(d) rulemakings because Group members own and operate existing EGU facilities throughout the U.S. and either have or may develop plans to construct and operate new EGU facilities in the future.

The electric generating industry is leading the transition to a clean energy future, voluntarily reducing emissions over the past decades, as well as pledging to continue to do so, despite the lack of GHG emissions standards for existing sources at the federal level.[3] Among other initiatives to reduce emissions, the electric generating industry has retired nearly 550 coal-fired EGUs between 2010 and the first quarter of 2019.[4] More units have retired or been decommissioned since then, and 23% of coal-fired EGUs operating as of November 2022 are scheduled to retire by the end of 2029.[5] Several Group members also have established voluntary carbon reduction goals and recognize the key role that fossil fuel-fired EGUs, particularly natural gas-fired EGUs, will play during this transition. Many electric generating companies will continue to rely on natural gas as a significant source of fuel in the near- and medium-term because the flexibility and affordability of natural gas-fired EGUs make them a critically important,

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[1] EPA, Posting EPA-HQ-OAR-2022,0723, Sept. 1, 2022, posted to docket on Sept. 8, 2022, https://www.regulations.gov/document/EPA-HQ-OAR-2022-0723-0001.

[2] *See* Attachment A for a list of Class of '85 members supporting these comments.

[3] *See* EPA, Sources of Greenhouse Gas Emissions, https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions#electricity ("Greenhouse gas emissions from electric power production have decreased by about 21% since 1990 [to 2020] due to a shift in generation to lower- and non-emitting sources of electricity generation and an increase in end-use energy efficiency.").

[4] *See* U.S. Energy Information Administration, "More U.S. coal-fired power plants are decommissioning as retirements continue" (Jul. 26, 2019), https://www.eia.gov/todayinenergy/detail.php?id=40212.

[5] *See* U.S. Energy Information Administration, "Nearly a quarter of the operating U.S. coal-fired fleet scheduled to retire by 2029," (Nov. 7, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54559.

dispatchable resource in meeting peak and seasonal energy demand, particularly as more intermittent clean energy resources are added to the national electric generating fleet. Thus, as the transition to clean energy is underway, fossil fuel-fired EGUs remain a necessary complement to renewable energy.

As electric generators, Class of '85 members have a responsibility to their individual customers and the general public to ensure that electricity remains affordable to households and businesses across the U.S. and that it meets the reliability standards approved by the Federal Energy Regulatory Commission ("FERC") — factors necessitating the continued availability of fossil fuel-fired electricity. The Group also must support the rapidly growing demand for electricity as various sectors, including the automobile industry, shift to electrification. Such demand will continue to increase in the future, as reflected in Group members' integrated resource plans ("IRPs").

The Group appreciates EPA opening the non-rulemaking docket to provide the opportunity for public input and to gather perspectives from a broad group of stakeholders. Such perspectives, particularly from the electric generating sector, are crucial to establishing GHG emissions standards under CAA Section 111 that do not threaten electricity reliability or hinder the move to clean energy. As further discussed below, the Group recommends that EPA: (i) not mandate control technologies that have yet to be adequately demonstrated to improve GHG emissions performance at fossil fuel-fired EGUs, including carbon capture, utilization, and storage ("CCUS"); (ii) create subcategories of sources and establish mass-based carbon dioxide ("CO_2") limits in addition to rate-based CO_2 limits for existing and new fossil fuel-fired power plants; and (iii) provide states with a broad array of tools and flexibilities for designing state plans that establish, implement, and enforce standards of performance for CO_2 from existing fossil fuel-fired power plants.

II. COMMENTS

EPA has an important role in supporting the transition to clean energy. In developing the CAA Section 111(b) and 111(d) rulemakings, EPA should continue to recognize that, while a clean energy transition is underway, renewables nonetheless present several challenges, and more time and research is needed to resolve them. In the meantime, fossil fuel-fired EGUs will continue to play an essential role in providing firm dispatchable generation to support current demand and intermittent renewable generation while the electric generating sector works through resolving the challenges renewables present.[6] Fossil fuel resources are essential to support increased reliance on renewables while ensuring reliable and affordable electric generation to minimize impacts to customer rates.

For the Section 111 rulemakings to be viable during this transition, EPA should offer compliance flexibility in the standards and requirements that the Agency establishes to allow electric generators and public utility commissions ("PUCs") to make strategic decisions — for example, whether to continue to operate existing EGUs or instead retire them and invest in new

[6] The current infrastructure in the electric generating industry is being dismantled at a faster rate than new, renewables technologies and infrastructure are being implemented. Also, the current state of renewables is not sufficiently robust to meet the growing demand of electricity, as reflected by the recent cold weather shut down of renewable energy sources in the Midwest, blackouts of power supplies, and mandated reductions in power consumption to avoid outages.

generation sources — that achieve the common goal of decarbonization while continuing to provide reliable and affordable electricity to customers. In some instances, it may be extremely difficult to retire units that have hundreds of millions of dollars in stranded costs that customers would have to pay if the units were forced to retire sooner than planned. According to one Group member, it has added various control technologies to its two, 30-plus year old coal-fired EGUs to comply with various regulatory requirements — low-NOx burners with overfire air and dry scrubbers for compliance with the Regional Haze requirements and activated carbon injection systems with associated monitoring equipment for compliance with the Mercury and Air Toxics Standards ("MATS") — and has scheduled to convert the units' wet bottom slurry systems to dry systems in the next two years for Effluent Guidelines Plan ("ELG") compliance. The investment required to install these control technologies has totaled well over $1 billion in the last 10 years, which makes it nearly impossible to retire the units in the near future without assurances that additional control technology will not be imposed under Section 111(d). For this and other similarly situated older EGUs, EPA could consider reaching an agreement with their owners/operators to retire the units by a date certain, in exchange for assurances that no new controls would need to be installed. Such an agreement would more easily accomplish a cadence of step-wise GHG reductions for older units and would be more palatable for PUCs and customers.

The Class of '85 also recommends that EPA collaborate with other agencies, including the U.S. Department of Energy ("DOE"), FERC, North American Electric Reliability Council, regional transmission organizations ("RTOs"), and independent system operators ("ISOs") in developing CAA Section 111(b) and 111(d) rulemakings. EPA should take into consideration the incentives and funding initiatives provided by DOE for the research, development, demonstration, and deployment ("RDD&D") of GHG emissions reduction technology to ensure that the standards established in the Section 111 rulemakings do not discourage or hamper those efforts — for instance, by setting standards that would force the use of a certain technology. This could direct funds away from researching novel technologies to implementing the mandated one.[7] Further, EPA should consider collaborating with DOE to provide funding initiatives to pay off the stranded costs invested in older units, making it easier and faster to retire older units and to replace them with newer and more efficient units that require less GHG-intensive technologies.

The Class of '85 offers the recommendations below in response to the questions posed by the Agency.[8] The Group also incorporates by reference its comments on EPA's Draft White Paper, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units," Dkt. No. EPA-HQ-OAR-2022-0289 (Apr. 21, 2022).[9]

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[7] *See* DOE, "Biden-Harris Administration Announces $550 Million in Clean Energy Funding to Benefit and Lower Costs for More than 250 Million Americans, Nov. 22, 2022, https://www.energy.gov/articles/biden-harris-administration-announces-550-million-clean-energy-funding-benefit-and-lower#:~:text=WASHINGTON%2C%20D.C.%E2%80%94The%20Biden%2D,more%20than%20250%20million%20Americans.

[8] EPA, Questions for Consideration, posted to docket on Sept. 15, 2022, https://www.regulations.gov/document/EPA-HQ-OAR-2022-0723-0002.

[9] The Group's comments were submitted to that docket on June 6, 2022 (Doc. ID. EPA-HQ-OAR-2022-0289-0021) and are attached here as Attachment B.

A. EPA Should Not Impose Standards Based on Control Technologies that Have Yet to be Adequately Demonstrated to Improve GHG Emissions Performance.

In developing GHG emissions guidelines under CAA Section 111(d) for existing EGUs and New Source Performance Standards ("NSPS") for GHG emissions under CAA Section 111(b) for new, modified, or reconstructed EGUs, EPA should recognize that the majority of GHG emissions reduction technologies are still under development and have yet to be proven at scale, let alone be commercially available. Further, significant infrastructure development would be needed to support technologies such as CCUS and hydrogen generation. Thus, prior to basing standards under CAA Section 111 on these technologies, EPA must allow time for the technologies to advance and be adequately demonstrated to provide reliable and consistent performance. CCUS, for instance, has not yet been adequately demonstrated for fossil fuel-fired EGUs without subsidies or governmental funds.[10] EPA should, however, allow such technologies to be used as compliance tools to meet Section 111(d) and 111(b) standards.

EPA should determine the Best System of Emissions Reduction ("BSER") based on the current status of GHG emissions reduction technologies to ensure any technologies that are necessary to meet standards established under CAA Section 111 rules are achievable in practice. BSER should be both "adequately demonstrated" and "achievable" in meeting the performance standards under CAA Section 111 rules.[11] The Agency also should evaluate whether the technologies identified as potential BSER can be readily implemented based on their current research and development status, how EGU- and geographic-specific factors may impact the viability of prospective technologies, and any inadvertent consequences such technologies may have on current systems and infrastructure supports. A one-size-fits-all approach is unlikely to work. Some of the key factors that EPA should consider include: EGU sizes, EGU types, variabilities in geographic locations, and the development of supporting infrastructure for the technologies particular to a specific EGU. Notably, the distance of a site from a sequesterable geology or oil field that can accept CO_2 is key to the ability to use CCUS.

Moreover, the Group asks that EPA take into account, in developing compliance tools for the CAA Section 111 rules, the myriad of voluntary efforts that the electric generating sector has taken to reduce emissions over the past decades. One way of recognizing those efforts is to allow credit for significant carbon reductions already undertaken. Such credit could be offered, for example, by allowing EGUs to achieve compliance with the Section 111 standards through a plant-wide or regional averaging plan, and would provide two specific benefits. First, it would acknowledge that the electric generating sector already has made significant strides towards lowering GHG emissions via voluntary CO_2 reduction efforts despite the absence of regulatory requirements. Second, it would avoid "penalizing" electric generating companies that already are undertaking such efforts by recognizing that they should not be treated the same as other companies that have not made as much progress in lowering their GHG emissions.

With respect to the CAA Section 111(d) rulemaking, EPA should evaluate the cost effectiveness for existing EGUs to invest in GHG emissions reduction technologies for compliance

[10] For example, while the Petra Nova project in Texas successfully captured and sequestered CO_2 starting in in 2016, it ultimately was shut down in 2020 due to economic factors despite having received $167 million from DOE and $250 million from the Japanese government in funding.

[11] *See* CAA Section 111(a)(1) (defining "standard of performance").

with EPA's emissions guidelines, especially when factoring in an EGU's remaining useful life.[12] This entails assessing whether it makes sense for existing EGUs, particularly EGUs that are slated to retire, to incur costs to meet stringent standards under CAA Section 111(d) that could impact their customers' access to affordable electricity. The Group urges EPA to consider making the compliance date of such rules consistent with the compliance date for other programs, such as the ELG under the Clean Water Act ("CWA").[13]

1. Improvements in operational or combustion efficiency currently present the most viable options for reducing GHG emissions from fossil fuel-fired EGUs.

The Group recommends that EPA prioritize considering work practice standards and/or best management practice standards geared towards improving operational and heat rate efficiencies to reduce GHG emissions at existing EGUs. Such standards would be easier, quicker, and less costly to implement than installing new control technologies — many of which are still in the RDD&D stage — that likely would result in permitting and, potentially, siting requirements. Also, units implementing best practice standards will be vital in maintaining reliability, grid stability, and supporting electrification throughout the economy if GHG emissions reduction technologies continue to be in the RDD&D stage and intermittency of renewables remains a concern in the future.

Subject to potential New Source Review permitting constraints, work practice and/or management practice standards could include, for example, replacing certain component parts associated with maintenance outages to improve output and efficiency. Such standards also could include implementing best operating and maintenance practices that are geared specifically at improving efficiency. These improvement projects, when applied independently or cumulatively, could provide an effective, economical EGU-specific improvement specifically aimed at reducing CO_2 emissions.

[12] Section 111(d) allows states to take remaining useful life and other factors into account in applying EPA's emissions standards to specific facilities, but EPA also should consider remaining useful life when establishing emission standards.

[13] *See e.g.*, 85 Fed. Reg. 64,650, 64,679 (Oct. 13, 2020) (where compliance date for the current 2020 ELG rule for EGUs to permanently cease coal combustion is December 31, 2028). In addition, under EPA's proposed federal implementation plan to address interstate transport for the 2015 ozone National Ambient Air Quality Standards, EPA has proposed to revise the Cross-State Air Pollution Rule ("CSAPR") to include a requirement that certain coal-fired EGUs meet a daily backstop NOx emission rate beginning in 2026. Nonetheless, EPA is considering exempting EGUs that retire by December 31, 2028, from meeting the daily backstop NOx emission rate. 87 Fed. Reg. 20,036, 20,122 (Apr. 6, 2022). Note, however, that the Group is merely referencing these EPA actions as examples. The Group is not suggesting that, the "outermost remaining useful life date" for an EGU to avoid installing BSER should be December 31, 2028, nor does the Group endorse the concept that EPA should set a specific retirement date in the Section 111(d) emission guideline ("EG") for fossil fuel-fired EGUs. *See* 87 Fed. Reg. 79,176, 79,201 (Dec. 23, 2022) ("[F]or a state to determine whether a retiring source qualifies for a less stringent standard, the EPA is proposing to require either that the Agency must identify in an EG an outermost remaining useful life date that would provide the latest retirement date that states can rely on for a designated facility or that the Agency must provide the methodology and considerations to be applied by states as part of their plans in determining whether a retiring source qualifies for a less stringent standard.").

2. EPA should reevaluate the standards for new simple cycle combustion turbines.

The Group recommends that EPA consider the vital role simple cycle combustion turbines ("CTs") play in supporting increased reliance on intermittent renewable resources while continuing to provide reliable and affordable energy and tailor standards to such use. A simple cycle CT has flexible operating characteristics, which are needed to support the grid during the transition to and while operating with renewables. It provides quick reaction times, which are critical when renewables are fluctuating or inoperable to prevent potential blackouts, has the capability to start up very quickly, and has minimum run time and down time.[14]

The composition of generation markets has changed significantly since Subpart TTTT was initially crafted, with the retirement of many older fossil fuel-fired units and the introduction of more renewables into the market. Further, the near-term resource plans for many Class of '85 members include significantly more renewables in the future. These changes to the generation resource mix have significantly increased the value of simple cycle CTs. As a result, EPA's original (2012-2014-era) assumptions regarding the role that simple cycle CTs would play in generation markets likely are no longer reasonable. EPA should revisit those assumptions and consider opportunities to add more flexibility to Subpart TTTT for simple cycle CTs.

Specifically, EPA should reevaluate the current Subpart TTTT, Table 2 limit structure. In crafting the Table 2 limits, EPA assumed that simple cycle CTs would serve only a more intermediate load-response or peaking generation role. As more renewable generation enters commercial operation, the fast start-up and ramp rates of simple cycle CTs become more valuable as these strengths pair well with the non-dispatchable nature of renewable sources. In some cases, the annual capacity factors of newer simple cycle CTs with relatively higher efficiencies might approach or even exceed a level that would pose challenges with the current Table 2 limits in Subpart TTTT. To Group members' knowledge, there are no simple cycle gas-fired CTs capable of meeting the first emission standard in Table 2 (1,000 lb CO_2/gross MWh or 1,030 lb CO_2/net MWh), which means that they must meet the indirect capacity factor limit in Table 2 to be subject to the emission standard of 120 lb CO_2/MMBtu. Indeed, some Group members report that they are limiting operation of simple cycle natural gas-fired CTs to avoid exceeding the indirect capacity factor limit, which in turn causes the regional electric generating market to utilize less efficient units in their place.

3. Co-firing with different fuels should be available as a compliance tool option but not considered as BSER.

Co-firing with different fuels — natural gas, biomass/renewables, and hydrogen — should not be determined as BSER. Instead, EPA should allow such co-firing as compliance tool options. The issues with considering these as BSER are discussed below.

Natural Gas Co-Firing: Natural gas co-firing largely hinges on the site-specific availability of, and access to, a sufficient supply of natural gas. To require natural gas co-firing for facilities where there is not an accessible and reliable supply of natural gas would force electric generating

[14] Group members note that methods to make CTs themselves more efficient are extremely limited.

companies to expend millions of dollars to site, permit, and install a natural gas pipeline, which also assumes the affected gas supply infrastructure would be able to accommodate the additional gas demand. The process of installing a natural gas pipeline, depending on its size, location, and length, likely would take years, and potentially even decades, to complete. Even in regions where there is a natural gas supply, there are other factors to consider that could render this option unviable. This includes: (i) the need to retrofit gas burner capacity; (ii) gas reliability concerns, such as volatility in natural gas prices, and delivery constraints, including limits on pipeline capacity and firm transportation; (iii) distance to a natural gas pipeline; and (iv) the need to expand gas pipeline capacity. Moreover, natural gas is more efficiently utilized in CTs than co-fired in steam boilers, especially those designed primarily for coal firing.

Biomass/Renewables: The Group encourages EPA, in line with the Agency's prior positions, to exempt from any CAA Section 111 rules biomass emissions from EGUs or EGUs that co-fire with or consume biomass. Biomass is considered a "renewable," not a fossil fuel.[15] Such an exemption would be consistent with other carbon reduction regulations, including the Regional Greenhouse Gas Initiative ("RGGI") model rules and certain state CO_2 budget trading rules. It also would be consistent with the Greenhouse Gas Reporting Rule, which treats biomass emissions as biogenic and requires separate calculation and reporting from non-biogenic emissions.[16] The Group recommends that EPA offer biomass/renewables co-firing as a compliance tool option because it largely hinges on the regional availability of biomass. Even where there is a supply of biomass available, EPA should note that other factors are likely to make this requirement impractical. These factors include the need to retrofit equipment and the costs associated with biomass fuel production, handling, and transportation, which are higher than for fossil fuels given that biomass is a lower-energy density fuel.

Hydrogen Co-Firing: Regional availability of hydrogen and hydrogen production are, at this time, very limited. The deployment of hydrogen to be used as fuel for reducing carbon emissions from the electric generating sector is an evolving technology that has not been fully demonstrated yet. Continued research and demonstration are needed to ensure reliable and safe development of hydrogen at scale throughout the U.S., as reflected by various federal programs. For instance, the Inflation Reduction Act ("IRA") provides additional policies and incentives for hydrogen, including a production tax credit, that will further boost the U.S. market for clean hydrogen. Similarly, DOE's National Clean Hydrogen Strategy and Roadmap provides opportunities to help ensure that hydrogen is developed and adopted as an effective decarbonization tool.[17] To assist in accelerating progress, the Class of '85 encourages EPA to

[15] *See* EPA, "EPA's Treatment of Biogenic Carbon Dioxide (CO_2) Emissions from Stationary Sources that Use Forest Biomass for Energy Production" (Apr. 23, 2018), https://www.epa.gov/sites/default/files/2018-04/documents/biomass_policy_statement_2018_04_23.pdf ("EPA's policy in forthcoming regulatory actions will be to treat biogenic CO_2 emissions resulting from the combustion of biomass from managed forests as stationary sources for energy production as carbon neutral); EPA, Memorandum on "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources" (Nov. 19, 2014), https://www.epa.gov/sites/default/files/2016-08/documents/biogenic-co2-emissions-memo-111914.pdf (considering how biogenic CO_2 emissions from stationary sources should be treated under the now-repealed Clean Power Plan and the Prevention of Significant Deterioration program.).

[16] *See* 40 C.F.R. § 98.33 (requiring separate calculation and reporting of biogenic CO_2 emissions from the combustion of biomass with other fuels).

[17] *See* DOE, "DOE Launches Bipartisan Infrastructure Law's $8 Billion Program for Clean Hydrogen Hubs Across U.S." (June 6, 2022), https://www.energy.gov/articles/doe-launches-bipartisan-infrastructure-laws-8-billion-program-clean-hydrogen-hubs-across (providing funding for developing regional clean hydrogen hubs across the U.S.,

work with DOE to provide assistance to the electric generating industry through funding available via the IRA so that this research can continue, as there are challenges related to safety, transportation, and storage that need to be addressed prior to any deployment at scale. DOE's support is needed to continue the research required to make hydrogen a successful mechanism, as part of its overall strategy to reduce carbon emissions.

Thus, adopting a standard that mandates hydrogen co-firing where a hydrogen supply is not available — or where the technology has not been fully demonstrated — would require electric generators to expend millions of dollars to site, permit, and install hydrogen infrastructure, which could include a hydrogen pipeline, and would likely take years, if not decades, to complete. Other factors that make hydrogen co-firing challenging, given the current state of the market and technology, include: (i) production and supply constraints; (ii) the potential need to retrofit equipment; and (iii) potential permitting concerns due to, for instance, increased NOx emissions. Moreover, the metallurgy in electric generating facilities is currently not capable of 100% hydrogen, and more time is needed for the electric generating industry to pilot this technology and work with the manufacturing sector to achieve 100% hydrogen blending. Until hydrogen co-firing has been fully researched and demonstrated, EPA should allow the technology as a compliance tool option but not consider it as BSER.

4. Integration with renewables and energy storage should be available as compliance tool options.

EPA should offer integration of renewables and/or energy storage as compliance tool options under CAA Section 111 rules but not mandate such integration. Requiring integration of renewables at an EGU facility could impede development of such generation at sites that are better suited for those technologies because resources could be diverted away from those sites and toward suboptimal renewables projects. For example, solar should not be required to be co-located at a facility that has limited land available or unfavorable topography, and a mandate to install solar at such a facility would be an unproductive and inefficient use of resources.[18] Electric generating companies and developers already are considering where to co-locate different types of renewables for economic, business, and resource-siting optimization. Accordingly, it would not be appropriate to require such installations under CAA regulations and could even be counter-productive or interfere with the ultimate goal of reaching net-zero emissions electric generation.

Also, while grid integration of standalone renewables and energy storage are further advanced and electric generators are beginning to gain experience with operating such systems to account for fluctuating resources at large scales, the direct integration of renewable or battery storage technology with EGUs is in its infancy. More research is necessary to ensure that the systems, which would become more complex over time, operate reliably to meet electricity demand and also comply with environmental requirements, such as those under the CWA and the Resource Conservation and Recovery Act. Electric generating companies currently are testing and researching operations, safety considerations, maintenance requirements, and long-term use to

which would "create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen as a clean energy carrier").

[18] Such a mandate also likely would be beyond the scope of EPA's authority under CAA Section 111 as that would redefine the source.

better understand how to effectively deploy and utilize the technology as an integrated and reliable component of the electric generating sector.

Additionally, more time is needed for integrating energy storage at an EGU facility to ensure that it can be successfully operated. At present, momentum has increased on the implementation of short duration (*i.e.*, less than four hours) battery storage systems ("BESS"), which largely have been lithium-based systems. However, some facilities already have experienced challenges with thermal runaway events, and these short duration systems are unable to meet long duration requirements when needed. There are significant research and commercialization efforts underway exploring alternatives to lithium, as well as longer duration energy storage systems. Federal grant programs, such as those under the IRA and the Infrastructure Investment and Jobs Act ("IIJA"), are currently supporting the commercialization and deployment of these alternatives. Similarly, thermal energy storage integrated with combined cycle CTs is not yet close enough in its development stage that it could be constructed and operated and could be limited by geographical location.

Studies are underway to evaluate and identify reliability issues and solutions so that renewables and energy storage can be integrated into the bulk power system, but additional time and research are needed to see how these developing technologies can help meet regional electricity demand. Electric generating companies also need to address issues related to the long-term use of such technologies.[19]

5. Post-combustion CCUS has not yet been adequately demonstrated.

EPA should not require post-combustion CCUS under CAA Section 111 rules because there are geographic and geological limitations that hinder CCUS, and more research is necessary to determine whether CCUS is a viable option for gas-fired EGUs. CCUS has only been deployed on baseload coal-fired EGUs, which more often provides consistent and long-term operations, and thereby may support the significant amount of capital and resource investment necessary to construct and operate CCUS equipment.

Amine technologies for CO_2 removal in the CCUS process are commercially available for coal-fired EGUs, and multiple companies are purportedly willing to offer commercial guarantees on solvent performance. However, research and testing of amine technologies for CO_2 removal on gas-fired EGUs have only begun.[20] More importantly, it is unclear whether CCUS can support

[19] For instance, as utility-scale solar assets age, it can lead to increased challenges with regards to maintaining peak operational performance. Global demand for replacement solar plant components has grown and is expected to grow into the future; and as utility-scale solar technology continues to evolve, finding compatible replacements for older units becomes increasingly difficult since manufacturers do not always produce replacements for legacy models and are focused on new product lines. *See also* World Economic Forum, "Here's How Supply Chain Issues Are Affecting Renewable Energy Projects" (Nov. 4, 2021), https://www.weforum.org/agenda/2021/11/supply-chain-problems-solar-power-renewable-energy/. As an example, new inverters are not always compatible with the existing solar infrastructure, which makes repowering facilities technologically more difficult. Moreover, evolving regulations continue to make it challenging for suppliers to maintain investments.

[20] *See* DOE "Biden-Harris Administration Launches $2.6 Billion Funding Programs to Slash Carbon Emissions" (July 13, 2022), https://www.energy.gov/articles/biden-harris-administration-launches-26-billion-funding-programs-slash-carbon-emissions (providing funding to advance CCUS projects, which would "focus on integrated carbon capture,

the variable operating conditions of gas-fired EGUs. Specifically, gas-fired CTs need to quickly respond to support more flexible electric generating scenarios, which entails a wide range of operating conditions, including high ramping rates, periods of minimum load operations, and the potential for multiple startups and shutdowns of the unit per day. Additionally, CCUS technology would require energy from the CTs to operate, which would decrease the efficiency of the CT.

Should CCUS eventually be adequately demonstrated for gas-fired EGUs, there are still additional hurdles for EPA to consider. For instance, CCUS would substantially increase the costs associated with constructing a new gas-fired CT facility, potentially making many such projects uneconomical. It could instead lead to a delay in transitioning the industry to cleaner generation. For example, companies might choose not to install newer, hydrogen-capable gas-fired CTs if they also were forced to install CCUS. Carbon sequestration technology also might require energy for directing steam from a combined-cycle CT's heat recovery steam generator to the carbon capture unit to operate. This would require the CT to fire more gas and produce a lower overall amount of net electricity for the grid, thus reducing the efficiency of the CT, and would result in an increase in upstream emissions from gas production and transport associated with increased gas utilization. Additionally, when using CCUS on combined cycle CTs, there are reductions in the CT's operating range. Current research and engineering evaluations are focused on addressing this issue, but such results to date have not been demonstrated. If CCUS were required for gas-fired CTs, they would have greatly reduced operating flexibility and would need to operate at higher capacity factors than CTs that are designed to respond to fluctuating power needs. Lastly, there are significant obstacles associated with CCUS permitting (*e.g.*, Class VI well permits for CO_2 injection for geological sequestration purposes, pipeline construction permits, etc.), construction, transportation, and storage, as well as potential legal liability concerns for transporting and storing CO_2.

B. EPA Should Create Subcategories of Sources and Establish Mass-Based CO_2 Limits for Existing and New EGUs.

In expressing proposed CO_2 limits for existing and new EGUs, the Class of '85 provides the following recommendations:

First, EPA should create subcategories for existing EGUs under CAA Section 111(d) and new, modified, and reconstructed EGUs under CAA Section 111(b) and tailor limits to those subcategories, which would help support resiliency and reliability in fleet transition. EPA should establish subcategories for units with low utilization and for units committed to retirement, similar to the current 2020 ELG rule.[21]

For natural gas-fired CTs, EPA should reevaluate the subcategories established in 40 C.F.R. Part 60, Subpart TTTT, Table 2 due to the increasing role of simple cycle CTs to support renewables. EPA should ensure that the subcategories adequately reflect that role and do not inappropriately limit such units' net energy output based on the outdated assumptions that informed the current standards. Specifically, the Group strongly recommends that EPA differentiate between combined cycle CTs and simple cycle CTs because they are different

transport, and storage technologies and infrastructure that can be readily replicated and deployed at fossil energy power plants and major industrial sources of CO_2").

[21] 85 Fed. Reg. 64,650 (Oct. 13, 2020).

equipment serving different purposes. The Group also recommends that EPA retain the subcategory for non-baseload units that combust 90% or less natural gas but not place any restriction on utilization or output for simple cycle CTs. Additionally, the Group recommends that EPA include flexibility for new, hydrogen-capable CTs, especially given that hydrogen fuel likely will become more available in the future. Establishing limits specific to each subcategory ensures resiliency and reliability of the grid. Reliability may be affected as older fossil fuel-fired units retire and are replaced by cleaner generating assets (*e.g.*, renewables), and the Group strongly urges EPA to consult with FERC, RTOs, and ISOs in establishing CAA Section 111 subcategories and limits.

Second, EPA should account for degradation of unit efficiency over time when proposing such limits. EPA should consider that operating efficiency also is correlated to the ambient conditions of a CT because highly efficient operations are not available under all ambient conditions and vary based on the location of a CT. For both new and existing EGUs, EPA should offer compliance flexibility by allowing electric generating companies to select from and "opt in" to multiple compliance options, such as the following:

- Setting mass-based (*e.g.*, tons per year) emission limits as an alternative to rate-based (*e.g.*, lb/MWh) emissions limits.

- Allowing regional or national emissions trading.

- Allowing EGUs to utilize emissions averaging to be based on a specific timeframe (*e.g.*, 12-month rolling average) on a multi-unit or fleet-wide basis rather than mandating unit-specific emissions limits.[22] This would be similar to the current 2022 federal implementation plan for Pennsylvania's NOx emission limits for coal-fired EGUs equipped with selective catalytic reduction technology.[23] For example, a multi-unit averaged emissions limit would allow a plant with multiple units to implement CO_2 reduction measures more easily and more cost-effectively.

- Establishing a subcategory for sources with low annual hours or capacity factors that already have or are willing to take a permit restriction. This would assist sources using coal, oil, or older gas units that may not operate as frequently and sources nearing retirement — *i.e.*, sources where the cost of installing CO_2 emission reduction technologies far outweighs the benefits. The Group recommends that EPA consider setting a capacity factor limitation at 10 percent to address source testing needs and the potential for operations during weather events. For example, a cold winter where natural gas is curtailed for days would require low capacity coal units to run. Establishing a subcategory for units operating at 10 percent or less on an annual basis would assist in ensuring the units are

[22] For multi-unit facilities, the plant-wide emissions average would be adjusted if a unit is retired, decommissioned, or otherwise no longer in operation. For facilities with only a single EGU for which there is no opportunity for plant-wide averaging, EPA should provide a longer rolling averaging period.
[23] *See* 87 Fed. Reg. 53,381, 53,385 (Aug. 31, 2022).

viable resources to support such weather events until there is sufficient capacity available from other units.[24]

- Exempting units that are less than 25 MWs — consistent with other programs, such as the Cross-State Air Pollution Rule ("CSAPR"),[25] the Acid Rain Program,[26] and RGGI — from complying with the provisions of the Section 111(d) and 111(b) rules.

Third, the Group recommends that EPA avoid establishing minimum GHG efficiency standards.[27] Setting such standards could limit starts or turbine ramp rates, thereby interfering with an EGU's ability to ramp up or down to accommodate intermittent renewable energy. Forcing an EGU to maintain operation above a specified minimum load point would in turn reduce the unit's ability to adjust output to respond to variable energy resources and the operator's ability to efficiently manage renewable generation that is tied to the grid.

Fourth, the Group recommends that EPA provide a permitting mechanism or exemption for testing of different technologies, which is necessary to determine the viability and effectiveness of new technologies, because many existing permits are specific as to fuel inputs (*e.g.*, pipeline natural gas requirements). Providing a pathway that allows for testing would avoid hindering electric generating companies in their efforts to continue to evaluate and test new technologies on a small-scale prior to progressing to full-scale operation.

C. EPA Should Provide States with Options for Designing State Plans.

EPA should provide states with a broad array of options and flexibility in establishing CO_2 standards and enforcing those standards. The availability of options to meet those standards will be crucial to mitigate the impact on customer rates and maintain system reliability while achieving GHG emissions reductions, which the electric generating sector already is undertaking. These tools include allowing states to:

- Adopt multi-unit averaging, mass-based or rate-based limits, and/or alternative forms of standards — for example, state-wide emissions budgets with options for trading either regionally or nationally (*i.e.*, a program similar to RGGI or CSAPR) — that have, at a minimum, equivalent stringency as the federal standards.

- Establish long-term compliance periods (*e.g.*, annual or multi-year periods) for EGUs while aligning compliance timelines with other regulatory programs (*e.g.*, ELG).

- Provide a broad array of emission reduction control options for achieving compliance with emission standards.

[24] EPA also likely would need to provide an offramp (or specific exemptions) from operating restrictions (*e.g.*, a capacity factor limitation) for reliability or emergency circumstances.
[25] 40 C.F.R. § 97.1004.
[26] 40 C.F.R. § 72.6.
[27] Should EPA establish such standards, the standards should incorporate the need of a unit to operate at a lower load (*i.e.*, lower efficiency) to support intermittent renewable generation.

- Establish alternative options if GHG emissions reduction targets are met via other state-based programs, such as through a state-specific carbon reduction plan or RGGI.

- Provide plants or fleets credit for retiring units (including for early retirements that occur prior to the effective date of the CAA Section 111(d) rule).

EPA also should provide states sufficient time to develop their plans to ensure that standards are realistic and can be appropriately implemented and enforced. This includes time for states to engage meaningfully with stakeholders and collaborate with PUCs, as well as incorporate feedback on proposed plans prior to finalizing.

EPA recently proposed certain time periods for the Section 111(d) implementing rules, which include requiring states to submit their plans to EPA within 15 months after EPA issues a standard.[28] Given the need to balance GHG emissions reductions with the provision of reliable and affordable electricity generation, it will be important for states to consult with their PUCs in the development of their plans. The timeframe that EPA proposed for the Section 111(d) implementing rules is unlikely to be adequate for most states to develop plans for EGUs under Section 111(d) and, accordingly, EPA must tailor the timeframes for the EGU Section 111(d) rulemaking to accommodate coordination with PUCs and effective engagement with other stakeholders as contemplated by the proposed Section 111(d) implementing rules.[29]

States also may wish to see to see the alternatives mapped out in IRPs to determine what the costs would be for ratepayers, which can take significant time. The Group therefore urges EPA to provide states with a longer timeframe of at least 36 months to submit their plans, consistent with state implementation plans under CAA Section 110. This approach would ensure that states have a sufficient amount of time to develop their plans to address GHG emissions from existing EGUs, which are likely to be complex, require significant analysis, and likely to garner substantial public interest.[30]

III. CONCLUSION

The Class of ’85 appreciates the opportunity to submit comments on the non-rulemaking docket. Many Group members already have voluntarily committed to reducing their GHG emissions and are well underway in exploring, if not already undertaking, initiatives to meet their commitment. The Group urges EPA to consider the recommendations above in establishing GHG emission standards under CAA Section 111 that provide room for compliance flexibilities. Such flexibilities would help integration with renewables and battery storage. More importantly, compliance flexibilities would encourage electric generating companies to continue to evaluate

[28] 87 Fed. Reg. 79,176, 79,182 (Dec. 23, 2022).
[29] *See id*.
[30] This approach would be consistent with the U.S. Court of Appeals for the D.C. Circuit’s decision in *American Lung Association v. Environmental Protection Agency*, 985 F.3d 914 (D.C. Cir. 2021). There, the D.C. Circuit held that EPA must consider all “important aspect[s] of the problem” in setting state plan submittal deadlines. The D.C. Circuit recognized that certain factors could impact EPA’s determination of a reasonable deadline, pointing to administrative burdens and other statutory considerations. *Id*. at 993. Consideration of such factors for EGUs point to a longer timeframe for a deadline for Section 111(d) state plans to accommodate sector-specific planning, and ensure grid reliability.

and test the viability of different technologies on a small-scale prior to progressing to full-scale operation while also ensuring that electricity remains affordable, equitable, and reliable.

Dated: February 27, 2023

Respectfully Submitted,

The Class of ‘85 Regulatory Response Group
contact@class-of-85.com

ATTACHMENT A

AES Corporation
Alliant Energy Corporation
Ameren
Arizona Public Service
Arizona Electric Power Cooperative, Inc.
Arkansas Electric Cooperative Corporation
Basin Electric Power Cooperative
City of Tallahassee
Cleco Corporation
Cogentrix Energy Power Management, LLC
Dairyland Power Cooperative
Dayton Power & Light Company
Dominion Energy
Duke Energy
Entergy Services, LLC
Evergy, Inc.
Florida Municipal Electric Association
Gainesville Regional Utilities
Great River Energy
Hawaiian Electric Company, Inc.
Indianapolis Power & Light Company
JEA
Lakeland Electric
Louisville Gas & Electric/Kentucky Utilities
Minnesota Power
National Grid
NRG Energy
OGE Energy Corp.
Orlando Utilities Commission
Portland General Electric
PowerSouth Energy Cooperative
Public Service Company of New Mexico
Rainbow Energy Center, LLC
Salt River Project
Talen Energy
Tampa Electric Company
Tucson Electric Power Company
Western Farmers Electric Cooperative
Xcel Energy Inc.

ATTACHMENT B

COMMENTS OF THE CLASS OF '85 REGULATORY RESPONSE GROUP

ON THE

DRAFT WHITE PAPER: AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM COMBUSTION TURBINE ELECTRIC GENERATING UNITS

Docket No. EPA-HQ-OAR-2022-0289

I. INTRODUCTION

On April 21, 2022, the United States Environmental Protection Agency ("EPA" or "Agency") published a draft white paper, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units" ("Draft White Paper"). The Draft White Paper provides EPA's view of the potential benefits and drawbacks of control techniques and technologies that could be used to reduce greenhouse gas ("GHG") emissions from stationary combustion turbines ("CTs"). According to the Agency, EPA anticipates that "the public dialogue on the draft [white paper] will help inform consideration of a Clean Air Act (CAA) section 111 standard for new natural gas electric utility generating units (EGUs),"[1] *i.e.*, the Agency's forthcoming proposal to revise the GHG new source performance standards ("NSPS") for fossil fuel-fired EGUs. EPA also expects that the white paper may be used to inform state and local actions to address climate change and permitting considerations for individual facilities, including prevention of significant deterioration ("PSD") permitting and best available control technology ("BACT") determinations for stationary CT GHG emissions.

The Class of '85 Regulatory Response Group ("Class of '85" or "Group") respectfully submits these comments on the Draft White Paper.[2] The Class of '85 is a voluntary, ad hoc coalition of over 40 electric generating companies from around the country that has been actively involved in the development and implementation of Clean Air Act rules affecting the electric generating industry for over 30 years, including the regulation of GHG emissions from new and existing EGUs.

The Group has a particular interest in the Draft White Paper and its use in any future rulemaking, as our members own and operate existing stationary CTs throughout the United States and either have or may develop plans to construct and operate new stationary CTs in the future. Members of the Class of '85 are actively involved in the transition to net-zero electric generation and recognize the key role that gas-fired CTs will play during this transition. Many customers will continue to rely on natural gas as a significant source of electric generation in the near- and medium-term because the abundance, affordability, and flexibility of natural gas-fired CTs make them the ideal backup resource until renewable energy is able to meet peak and seasonal energy demand. Load-following natural gas-fired CTs can quickly adjust their power output as demand for electricity and output from renewables (*e.g.*, solar and wind) fluctuates throughout the day,

[1] EPA Press Release, "EPA Releases White Paper on Reducing Climate Pollution from New Gas-Fired Turbines" (Apr. 21, 2022), https://www.epa.gov/newsreleases/epa-releases-white-paper-reducing-climate-pollution-new-gas-fired-turbines.

[2] Attachment A contains a list of the Class of '85 members that support these comments.

which will be especially important during summertime. For example, the North American Electric Reliability Corporation's ("NERC") 2022 Summer Reliability Assessment forecasts grid reliability challenges for regions across the U.S., with capacity shortfalls expected during peak summer conditions this year.[3] Thus, for the time being, natural gas-fired CTs remain a necessary complement to renewable energy. As electric generators, Class of '85 member companies have a responsibility to their individual customers and the general public to ensure that electricity remains affordable, equitable, and reliable—factors which each necessitate that gas-fired electricity remain available.

II. COMMENTS

A. The Draft White Paper Needs Improvement in Several Key Areas.

The Class of '85 appreciates that EPA took the time to develop the Draft White Paper and is providing the opportunity for public comment. The Group agrees with EPA that facilitating public dialogue on GHG emission reduction technologies and approaches is a beneficial addition to forthcoming rulemaking or permitting processes. We further believe that public involvement will assist EPA in producing a final White Paper that provides a more thorough assessment of GHG control technologies, as several key improvements to the Draft White Paper would make it a stronger, more useful document.

Overall, the Group is concerned that the Draft White Paper lacks sufficient depth in key areas of its analysis and fails to appropriately rely on relevant studies and other reference materials, making it an insufficient basis for such important Agency actions as Section 111 rulemakings or BACT determinations for PSD permitting. As an EPA-issued document, the final White Paper could be viewed by state and local permitting agencies as a proxy for their own thorough analysis of the commercial availability and viability of certain control technologies for GHG emissions from CTs. Because of the White Paper's intended use—to inform future rulemaking and policy decisions by EPA, state and local agencies, and businesses—the Class of '85 encourages the Agency to strengthen its investigation and research on CT control technologies, as well as increase the robustness of its analysis of these technologies. Specifically:

- The Draft White Paper should address both benefits and drawbacks of control technologies. The Draft White Paper focuses on the benefits of certain technologies and measures for reducing GHG emissions from CTs without going into detail about the challenges or downsides related to those options that must be weighed against the benefits. This results in an incomplete picture of the effect of each option.

- The Draft White Paper should compare cost and performance. EPA should further explore the costs and performance of the evaluated technologies. This should include life-cycle cost and reliability considerations, which are essential in determining the appropriate

[3] *See* North American Electric Reliability Corporation, *2022 Summer Reliability Assessment*, at 4 (May 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf ("Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions . . . . More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability.").

control technologies for a particular CT. For some electric generators, the costs of installing or implementing GHG controls are passed directly onto customers, so it is important that they be examined carefully.

- The Draft White Paper should assess the current viability of each technology. Although EPA recognizes that some of the technologies evaluated in the Draft White Paper are still in the development phase, the distinction between developing technologies and those that have been "developed" and put into commercial use should be explicitly addressed throughout the White Paper.

- The Draft White Paper should rely more heavily on technical, peer-reviewed supporting information. The Class of '85 is concerned that a number of the information sources referenced in the Draft White Paper are neither primary sources, nor are they in-depth examinations by qualified researchers or real-world operators of these technologies. In particular, a number of news articles are used as sources. Although these articles are an important source of information for members of the general public, they are insufficient bases for a technical paper that will inform the Agency's development of major regulations. A technical paper should be based primarily on technical analyses. Furthermore, the Draft White Paper is missing citations for key assertions and for certain exhibits.

  Additional technical analyses of the considered control technologies are available, including from electric generating companies and organizations that are actively researching these technologies. These resources can provide a more complete picture of the opportunities and challenges presented by each. The Class of '85 offers the following additional published research as a starting point and notes the section of the Draft White Paper where each may be informative:

  - Section 5.1: Impact of EGU Efficiency on CO_2 Emissions

    - EPRI, Report No. 3002013632, *Innovations for Improving Efficiency of the Next Generation of Combined-Cycle Power Plants: 2018 Technology Survey* (Dec. 10, 2018), https://www.epri.com/research/products/000000003002013632.

  - Section 5.4.5: Potential Efficiency Gains in the Bottoming Cycle

    - Gilad M. Guttmann and Yaniv Gelbstein, *Mechanical Properties of Thermoelectric Materials for Practical Applications* (Nov. 5, 2018), https://www.intechopen.com/chapters/60176.

    - EPRI, *Program on Technology Innovation: Advanced Nanostructure-Based Thermoelectric Solid-State Cooling and Energy Harvesting in Power Plants* (Oct. 30, 2017), https://www.epri.com/research/products/000000003002006991.

    - EPRI, *Thermoelectric Power Generation Assessment* (Feb. 23, 2004), https://www.epri.com/research/products/000000000001009453.

- Section 5.6.1: Steam-Cycle Integrated Renewables
  - National Renewable Energy Laboratory ("NREL") and Solar Dynamics, LLC, *Concentrating Solar Power Best Practices Study* (June 2020). https://www.nrel.gov/docs/fy20osti/75763.pdf.
- Section 5.6.3: Integrated Energy Storage
  - EPRI, *Hybridized Gas Turbine (GT) Plus Battery Energy Storage Systems (BESS): Technology Benefits and Application Barriers* (Sept. 3, 2021), https://www.epri.com/research/products/000000003002022317.
  - John E.T. Bistline and David T. Young, *Emissions Impacts of Future Battery Storage Deployment on Regional Power Systems*, APPLIED ENERGY Vol. 264 (Apr. 15, 2020), https://www.sciencedirect.com/science/article/abs/pii/S0306261920301902.
- Section 5.7: Post-Combustion Carbon Capture, Utilization, and Storage (CCUS)
  - Yang Du et al., *Zero- and Negative-Emissions Fossil-Fired Power Plants Using CO_2 Capture by Conventional Aqueous Amines*, INTERNATIONAL JOURNAL OF GREENHOUSE GAS CONTROL Vol. 111 (Oct. 2021), https://doi.org/10.1016/j.ijggc.2021.103473
- Section 5.9: Hydrogen
  - EPRI, *Technology Insights Brief: Hydrogen-Capable Gas Turbines for Deep Decarbonization* (Nov. 14, 2019), https://www.epri.com/research/products/000000003002017544.
- Section 5.9.1: Ammonia
  - EPRI, *Technology Insight Brief: Ammonia and Hydrogen Fuel Blends for Today's Gas Turbines—Combustion Considerations* (Feb. 1, 2021), https://www.epri.com/research/products/000000003002020043.

The Group recommends that EPA publish a revised draft of the White Paper for public review and comment prior to finalization. Note that members of the Class of '85 are continuing to review the Draft White Paper and are likely to have additional feedback that is not incorporated into these comments due to the limited duration of the comment period. The Group would gladly participate in any further opportunity to provide input on the Draft White Paper.

B. EPA Should Revise its Analysis of CT GHG Control Approaches.

The Group provides the following comments addressing specific GHG control technologies and methods evaluated in the Draft White Paper.

1. Combustion Turbine Technology and Emissions

The Draft White Paper should recognize that, in some circumstances, a modern simple cycle peaking unit can be a superior technology choice to the combined cycle configuration because the former has more flexible operating characteristics. In particular, the shorter start time, shorter minimum run time, and shorter minimum down time can make a simple cycle CT the preferable choice for a peaking unit. Combined cycle CTs operate at a higher efficiency, but they have greater GHG emissions compared to a simple cycle CT in standby service. In short, when permitting a CT that will supplement intermittent renewable generation, a gas-fired simple cycle peaking unit with a low capacity factor may have *lower* GHG emissions than a combined cycle unit with a higher capacity factor.

Regarding Section 5.3, Simple Cycle Combustion Turbines, based on the experience of certain Group members, the Class of '85 is wary of the claim that aeroderivative CTs categorically start faster than frame machines. Furthermore, a major disadvantage of aeroderivative CTs is they typically have at least twice the operation and maintenance costs of a frame machine—a factor not discussed in the Draft White Paper. However, start costs for aeroderivative CTs are lower than for frame machines.

The discussion regarding sulfur hexafluoride ("SF_6") on pages 16 to 17 is somewhat misleading. Users of the Draft White Paper should not simply rely on the kilovolt ("kV") rating of non-SF_6-containing equipment to indicate that it is commercially available. The interrupting current rating for such equipment also should be indicated to provide the information necessary to determine commercial availability.

2. Efficiency Issues and Improvements

a. Higher and Lower Heating Values

In Section 5.1, at the top of page 19, the following statement is incorrect: "Consequently, the HHV heat rate for a given EGU is always *lower* than the corresponding LHV heat rate because the reported heat input for the HHV is larger" (emphasis added). The higher heating value ("HHV") heat rate is always *higher* than the corresponding lower heating value ("LHV") heat rate. The Draft White Paper seems to conflate heat rate with efficiency. Heat rate and thermal efficiency have an inverse relationship. Accordingly, the next sentence in the paragraph also is inaccurate: "For natural gas, the HHV heat rate is approximately 10 percent lower than the corresponding LHV heat rate." It would be more accurate to say: "For U.S. pipeline natural gas, the HHV is approximately 10 percent higher than the corresponding LHV, and varies slightly based on the actual constituent composition of the natural gas. This results in the HHV heat rate being approximately 10 percent higher than the corresponding LHV heat rate." Alternatively, the last sentence could state: "This results in the HHV efficiency being approximately 10 percent lower than the corresponding LHV efficiency."

Footnote 20 incorrectly states that the HHV heat rate is equal to the LHV heat rate "divided by 1.108." This should be changed to "multiplied by 1.108." Footnote 20 also should include the following caveat: The HHV/LHV ratio is dependent on the composition of the natural gas; *i.e.*, the percentage of each chemical species (methane, ethane, propane, etc.) within the pipeline natural

gas will slightly move the ratio. Generally speaking, U.S. pipeline natural gas is stripped of enough heavier hydrocarbons that the ratio of approximately 1.108 is typically achieved across the country; however, it is worth noting that this is not a ratio that "automatically" applies to all natural gas.

The last sentence of the first paragraph on page 19 could benefit from the following clarification, with proposed new text shown in italics for ease of review: "Manufacturers typically use the LHV to express the heat rate of combustion turbines, *as the exhaust stream rarely reaches a temperature cold enough to extract useful work associated with condensing combustion moisture*." In addition, it may be worth noting that pipeline natural gas is sold on a HHV basis, despite the fact that very few end-user processes can take advantage of the HHV heat content level—hence the typical need to convert to LHV.

b. CT Operating Efficiency and Expected Degradation

The Group has the following suggestions for page 20, which lists factors that bear on a CT's efficiency:

- *EGU plant size*: This statement may conflate the factors at issue. Larger machines are generally newer designs and therefore will contain the latest hardware upgrades that improve operating efficiency. Thus, plant size is not necessarily the cause of increased efficiency.

- *EGU operating and maintenance practices*: This bullet is only partly correct. Although owners/operators dictate some of the specific operating and equipment management practices for an EGU, these practices also are influenced—and in some cases, determined—by the equipment's Original Equipment Manufacturer ("OEM") requirements.

- *EGU geographic location:* While this bullet is correct that air pressure is lower at higher altitudes, it is not correct to say that less oxygen is available for combustion at higher elevations, nor is it the reason for decreased CT output at higher elevations. The percentage of oxygen in dry air is at a constant 21 percent at all altitudes,[4] and this oxygen level is sufficient to support combustion. The reason CT output is reduced at higher elevations is because of the air pressure: lower air pressure decreases the molecule count in the air (*i.e.*, the air becomes less dense), and the lower density means that less mass flows through the compressor. Less air mass flow means less working fluid (*i.e.*, exhaust gas) is available to expand in the turbine section of the EGU, thereby resulting in less power output at higher elevation. Similarly, there is no reduction in the compressor workload associated with cooler ambient temperatures; instead, there is a higher mass flow rate due to the higher density air in colder temperatures, which generally results in higher output at colder temperatures. The Class of '85 believes that increasing the draft pressure of the heat recovery steam generator ("HRSG") is inapposite in the discussion of improving

[4] *See* Andrew J. Peacock, *ABC of Oxygen: Oxygen at High Altitude*, BMJ Vol. 317(7165) at 1063–66 (Oct. 17, 1998), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC1114067/.

efficiency. In fact, the opposite would be expected: an increase in exhaust pressure would result in a *loss* of output. EPA should reassess these statements carefully.

- *EGU load generation flexibility requirements*: The Group agrees with the statement that operating as a base load unit is generally more efficient than cycling, operating at part load, or peaking. However, it is rare that a CT has the opportunity to operate at base load all of the time. This is because operations are generally controlled by the independent system operator (*e.g.*, MISO, as discussed in footnote 3 of these comments), and are therefore outside of the control of the CT operator. Additionally, the Draft White Paper attributes load cycling and the need for flexibility to fluctuations in customer demand. However, the primary need for flexible dispatchable natural gas generation is—and will continue to be—to accommodate increased integration of renewables and variable resources into the grid through CT operations. This may include reduced CT generation levels, increased CT ramping rates, reduced start and stops costs, and minimum down time.[5]

In general, the Draft White Paper's discussion of operating efficiency should better account for the sensitivity of combined cycle CTs to ambient conditions. While this consideration is noted in Section 5.4.4, users of the White Paper should know that high efficiency is not available at all CT sites or in all ambient conditions. Relatedly, the Class of '85 is concerned with the apparent trend identified in Exhibit 5-5 showing decreased efficiency with increased ambient temperature. This appears to be inconsistent with other publications. For example, efficiency for a combined cycle unit may be at its maximum when at International Standards Organization ("ISO") conditions, declining on each side of that maximum. In other words, lower temperature does not automatically correlate to increased efficiency. EPA should provide a citation for this information so that it can be better evaluated.

The Class of '85 recommends that EPA consider the potentially significant trade-offs of setting efficiency standards solely on a per-CT basis, including the potential for efficiency standards to limit the flexibility of units and hamper the integration of renewables.[6] Minimum GHG efficiency standards could limit starts or turbine ramp rates, thereby interfering with a CT's ability to ramp up or down to accommodate intermittent renewable energy. Additionally, if a CT must operate above a minimum load level to engage the control equipment, it would in turn reduce the unit's ability to respond to variable energy resources and the operator's ability to manage renewable generation that is tied into the grid.

The Group further recommends that EPA consider degradation of efficiency over time. The Draft White Paper states on page 12 that "[s]tate-of-the-art power blocks achieve design net thermal efficiencies greater than 58 percent on a HHV basis (64 percent on a LHV basis)." However, units do not operate at "design efficiency" and efficiency decreases over the lifetime of the unit such that these efficiencies are not sustainable over time. The discussion also should include the degrading effects of a plant's operating decisions to maintain availability, such as running redundant pumps.

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[5] *See* NREL, *Western Wind and Solar Integration Study* at 309 (May 2010), https://www.nrel.gov/docs/fy10osti/47434.pdf.

[6] *See* NREL, *The Western Wind and Solar Integration Study Phase 2: Executive Summary* (Sept. 2013), https://www.nrel.gov/docs/fy13osti/58798.pdf.

c. Technology- and Approach-Specific Considerations Regarding Operating Efficiency

In Sections 5.2 thorough 5.4 of the Draft White Paper, the Class of '85 agrees that the common CT technologies that provide for upgraded power plant efficiency and improve heat rates to lower GHG emissions are generally reasonable and commercially available. However, certain other technologies have not been widely adopted or are currently in an early research-and-development phase and will not be available for commercial deployment in the foreseeable future. One such example is hybrid cooling, which is discussed in Section 5.4.3.

In Section 5.3.1, Maximum Theoretical Combustion Turbine Efficiency, the Group recommends that the list of "other performance enhancements" include not just steam injection, but also air injection. Air injection is a proven technology that is similar to inlet chilling in that it addresses the CT's sensitivity to ambient temperature changes.[7]

In Section 5.3.2, regarding the impact of ambient conditions on simple cycle CTs, the following statement is overly simplistic: "[o]ne approach owners/operators of combustion turbines can take to reduce the efficiency and capacity losses due to higher ambient temperatures is precooling the combustion air." This statement does not account for turbine controls that protect the machine (*e.g.*, anti-icing and shaft limits). The Draft White Paper should clarify that—given the large mass of air used as the working fluid causes additional inefficiencies (*e.g.*, increased inlet differential pressure ("DP") for evaporative cooling, parasitic load for fogging and chilling)—reducing air temperature should be considered before applying this general conclusion.

Footnote 30, discussing inlet cooling options for simple cycle CTs, should be incorporated into the main text of the discussion of ambient conditions for combined cycle CTs in Section 5.4.4. Additionally, the statement in footnote 30 about evaporative coolers losing their effectiveness in humid climates is overstated and should be adjusted. In the experience of Class of '85 members, evaporative cooling can be quite effective in moderately humid climates, *i.e.*, throughout most of the United States.

Regarding Section 5.4.3, water impacts are a factor in the selection of cooling system technologies; however, such impacts are highly site-specific. In addition, just as life-cycle economics play a key role in the evaluation of CT technology, they also affect the evaluation of cooling systems.

The Group recommends expanding the discussion of "the relatively large water-related ecological concerns" of cooling systems on page 20; additionally, it would be helpful to reiterate the ecological impacts discussion in Section 5.4.5 when discussing once-through supercritical HRSGs. Furthermore, while supercritical steam cycles have been widely implemented on large steam plants, there is limited (if any) application in the United States for the smaller steam turbines in combined cycle configurations. Startup considerations for intermediate load applications may diminish the CO_2 emissions benefit. In addition, the commercial development status for the use of alternative working fluids should be made clear in the Draft White Paper. EPA should conduct

[7] *See, e.g.*, Powerphase LLC, *Air Injection Technology – Turbophase*, https://powerphase.com/turbophase-air-injection (last accessed June 1, 2022).

outreach to CT owners/operators to learn about their domestic installation experience and duration of service; such information will add much-needed perspective to this section.

EPA also oversimplifies the efficiency of combined cycle EGUs with HRSG bypass stacks. On page 26, EPA states "[t]hese fast-start, combined cycle EGUs incorporate multiple techniques to allow the EGU to start and stop faster, cycle output faster, and maintain higher part load efficiencies than previous designs. These design features include an HRSG bypass stack that allows the combustion turbine engine to operate independent of the HRSG." In reality, gas leakages through the bypass stack may contribute to a loss in cycle efficiency. There also are additional maintenance and reliability considerations with bypass dampers over the life cycle of the equipment, as increased use of bypass dampers introduces an additional potential mode of failure.

The Class of '85 suggests clarifying the following statement on pages 25 to 26: "A triple-pressure HRSG with a reheat cycle improves the efficiency of thermal energy to electrical output to approximately 30 percent." This sentence should be given additional context because 30 percent is not generally considered a high number when discussing power plant efficiency.

Decisions on adding operational flexibility to decrease GHG emissions would be highly unit-specific and depend on which other units exist to serve the same load centers. Thus, in Section 5.4.1, it would be helpful to add clarifying statements on how decreasing combined cycle EGU start times and adding flexibility to such units can actually *decrease* a unit's overall efficiency (*i.e.*, raising its overall GHG impact), depending on how the unit will operate over the long term. A similar trade-off analysis is briefly included in Section 5.4.2, discussing duct burners and supplemental firing. Additionally, in Section 5.4.2, the general statement that combined cycle EGU efficiency decreases with increased duct burner capacity is correct; however, this discussion suggests a larger effect than what some Group members have experienced with similar configurations.

Finally, there are several references throughout the Draft White Paper to an industry publication called Gas Turbine World ("GTW"). GTW is a general reference for CT-based electric generating units. The Class of '85 cautions that, for this type of document, the source of data, the timeliness of the data, and the consistency between suppliers should be carefully reviewed before drawing any technical conclusions from the data. It is not clear from the Draft White Paper whether such review of the underlying data has been conducted by EPA.

3. Combined Heat and Power

The feasibility of combined heat and power ("CHP") facility arrangements is highly dependent on the individual application because the thermal loads of hosts typically are unique (*e.g.*, steam quality and quantity). The load shape and demands on the particular EGU and the thermal host do not always align to maximize efficiency. While demand imbalances can be mitigated with additional capabilities, this comes with an added cost and a reduction in overall efficiency. As steam host demands increase, power generation generally decreases; therefore, the higher efficiency CHP cycles generally have comparatively diminished power generation. EPA is therefore providing an incomplete picture of CHP efficiency when it states that "the overall fuel

efficiency of CHP can be 80 percent or higher and requires less fuel overall than if the electricity and steam were generated separately."[8]

The Draft White Paper would benefit from a thorough discussion on economics, despite claiming that "CHP EGUs are providing reliable, low-cost thermal energy to thermal hosts."[9] The Class of '85 recommends that EPA either delete this statement or provide an economic analysis that supports its claim that CHP is low-cost compared to other EGU configurations.[10] The Group appreciates EPA's acknowledgement that it may not be "economically feasible" to design an EGU as a CHP facility,[11] but urges EPA to explain what considerations and analysis underlie a determination that a control technology is "economically feasible," including whether this determination is made on a company-by-company basis. One Group member notes that, in addition to the significant amount of CHP already on their system, the company frequently has customer opportunities to install CHP, but those opportunities rarely make economic sense for the customer or the company to pursue.

4. Integrating Renewable Energy

Section 5.6.1, Steam-Cycle Integrated Renewables, states that concentrated solar is cost-effective, particularly in terms of capital costs and carbon abatement. EPA should explain the basis for its statement that it is "cost-effective," particularly with respect to which other options are being compared. Further evaluation of costs is needed throughout the Draft White Paper, and especially in this section.

If co-locating renewables and energy storage is mandated as a control method, it could impede the development of such co-location at sites that are better suited for those technologies because resources would be diverted away from those sites and toward suboptimal renewable projects. For example, solar should not be co-located at a facility that has limited land available, and a mandate to install solar at that facility would be an unproductive use of resources. Utilities and developers already are considering co-locating different types of renewable resources for economic- and business-case optimization; accordingly, it may not be appropriate to require these installations under Clean Air Act regulations, and could even be counter-productive to the ultimate goal of reaching net-zero emissions electric generation.

In general, the extensive discussion of energy storage technologies in Section 5.6.3 takes the focus away from the purpose of the Draft White Paper as it is stated in Section 1.0: "While some developing technologies are noted as such, inclusion in this white paper generally represents that a technology or measure is sufficiently well-developed that it could be constructed and successfully operated to achieve its intended purpose in the identified applications but not necessarily that it meets the applicable standard for it to be required under any particular regulatory program." Thermal energy storage integrated with combined cycle CTs may be close to fitting this criteria; however, at this time it is not "sufficiently well-developed that it could be constructed

[8] Draft White Paper at 30.
[9] Draft White Paper at 31.
[10] The Draft White Paper would be further improved by additional economic analysis for each technology it evaluates.
[11] Draft White Paper at 31.

and successfully operated." This section should therefore come with a clearer caveat about the level to which integrated energy storage currently is feasible.

EPA should consider the potential challenges of direct integration of renewable generation or battery systems with CT and plant operations. While grid integration of standalone renewables and batteries is well underway, and utilities are gaining experience with system operations to account for fluctuating resources at large scales, the direct integration of renewable or storage technology with EGUs is in its infancy. More research is necessary to ensure that the systems, which will become more complex over time, can be reliably operated to meet electricity demand and comply with environmental requirements. Compared to the operations of traditional fossil generation, battery energy storage system ("BESS") technology is in its early stage of development and some facilities have already experienced failures and challenges with thermal runaway events.[12] Electric generating companies currently are testing and researching operations, safety considerations, maintenance requirements, and long-term use to better understand how to effectively deploy and utilize the technology as an integrated and reliable component of the power system.[13]

Exhibit 5-9 lists various energy storage technologies; however, the analysis in Section 5.6.3 of the Draft White Paper largely focuses on battery technology. Because of energy storage systems' significant potential for lowering GHG emissions, the Class of '85 recommends that EPA include a more robust and detailed review of the other storage technologies listed in Exhibit 5-9—including the benefits and drawbacks of each method. For example, the Draft White Paper should examine whether storage technologies that are charged by gas-fired turbines would increase the GHG intensity of the turbine. The same is true for other technologies identified in the document, such as carbon sequestration.

Finally, as has been recently reported in the press, electric generating companies—including Class of '85 members—have been affected by the lack of availability and increased costs of photovoltaic solar panels and lithium-ion batteries, which are causing wide-spread delays in the installation of renewable projects.[14] Supply-chain delays should be incorporated into the Draft White Paper as a pivotal factor in the viability of such proposed projects.

5. Carbon Capture, Utilization, and Storage

The Class of '85 believes that Section 5.7 of the Draft White Paper is overly optimistic about the current and near-term status of post-combustion carbon capture, utilization, and storage ("CCUS"). Most importantly, although the Draft White Paper provides several examples of CCUS demonstrations at coal-fired EGU facilities, it does not include any existing representative demonstration projects for gas-fired CTs. CCUS has been deployed thus far only on baseload coal-fired EGUs that provide a consistent and long-term operating environment, which supports

[12] *See, e.g.*, EPRI, *BESS Failure Event Database* (Apr. 14, 2022), https://storagewiki.epri.com/index.php/BESS_Failure_Event_Database.

[13] *See, e.g.*, EPRI, *Hybridized Gas Turbine (GT) Plus Battery Energy Storage Systems (BESS): Technology Benefits and Application Barriers* (Sept. 3, 2021), https://www.epri.com/research/products/000000003002022317.

[14] *See, e.g.*, UtilityDive, *Supply-Chain Squeeze: Solar, Storage Industries Grapple with Delays, Price Spikes as Demand Continues to Grow* (Mar. 31, 2022), https://www.utilitydive.com/news/solar-storage-delays-price-supply-chain/620537/.

the significant amount of capital and resource investment necessary to construct and operate the CCUS equipment. Because electric generators will increasingly need their natural gas generation to be more flexible with high ramping rates, periods of minimum load operation, the potential for multiple starts per day, and large fluctuations in emissions, EPA should further investigate whether CCUS for CTs can be a viable technology in consideration of these more variable operating conditions.

The Draft White Paper should closely examine the examples it cites and provide a detailed explanation of the status of each, including whether the project is still operational or in development, the scale of the project (*e.g.*, pilot or commercial), whether the project is the first of its kind, if it has demonstrated consistent operation over time, and the reasons for a project's shutdown if a project has since ceased operation (*e.g.*, was it cost prohibitive or were there reliability issues?). Evolving technologies under development should include a projected availability timeframe for commercial application on large, utility-scale plants. Section 5.7 briefly mentions a CCUS project at a Bellingham, Massachusetts combined cycle plant, which operated from 1991 to 2005, and otherwise focuses on projects that are in the early stages of development or pertain to other types of EGUs. This does not indicate a technology that is "sufficiently well-developed that it could be constructed and successfully operated."[15] A proposed or developing project, such as the Peterhead CCUS Power Station in Scotland, is not proof of a technology being available. This is underscored by the following statement in Section 5.7: "A storage site being developed 62 miles off the Scottish North Sea coast *might* serve as a destination for the captured CO_2" (emphasis added).

Amine technologies used for CO_2 removal in the CCUS process are commercially available for coal-fired EGUs and industrial processes, and multiple companies are willing to offer commercial guarantees on solvent performance; however, researching and testing of amine systems on CTs has begun only recently. These systems will not be available in the near term for large-scale deployment. Further, the Draft White Paper does not evaluate the creation of non-CO_2 emissions associated with applying amine-based capture to natural gas combined cycle CTs. The U.S. Department of Energy ("DOE") will be requiring testing and analysis of these potential emissions with all technology development projects going forward—this testing and analysis should similarly be included in EPA's evaluation of the technology.

The Group notes that several of the technologies mentioned are not yet proven at *any* scale. Alternatives to amine scrubbing for CO_2 removal are unproven. Polymeric membranes have shown potential for carbon capture from coal-fired flue gas streams; however, they are challenged by the lower CO_2 partial pressures and concentrations from natural gas combined cycle units. Combination solvent/membrane systems are not yet ready for demonstration, and solid sorbents are developing technologies but have yet to be demonstrated at the relevant scale for use with CTs. The Draft White Paper refers to fuel cells configured for emissions capture as a "viable CCUS technology."[16] To date, no field test data have been made publicly available that confirm that this technology is viable.

[15] Draft White Paper at 6.
[16] Draft White Paper at 40.

Technology testing at the National Carbon Capture Center ("NCCC") in Alabama and Test Centre Mongstad ("TCM") in Norway has been valuable in evaluating technologies and moving them through the development curve to prepare them for demonstration. Several technologies that have been tested at those facilities are now in the front-end engineering design ("FEED") stage, which will refine the expected costs of those technologies. However, a technology needs to be demonstrated at a scale above that of NCCC or TCM to realistically be considered "commercially available." Continued public/private partnerships with DOE will be critical to reducing the risk to electrical customers through technology development at test centers and eventual demonstration at commercial scales. Group members have been and will continue to be involved in supporting such efforts, which gives these companies particular insight into the low likelihood that CCUS will be sufficiently developed to be considered as a viable CO_2 control technology in forthcoming proposed rules under Clean Air Act Section 111.

The Group provides the following additional comments on the CCUS section:

- Section 5.7 fails to recognize that carbon sequestration technology will require energy from the gas-fired CT to operate, which will cause the CT to fire more gas and produce a lower overall amount of electricity. This reduces the efficiency of the gas-fired CT.

- The Draft White Paper does not sufficiently address the challenges of CCUS permitting, construction, transportation, or storage—which include potential legal liability for transporting and storing CO_2—nor does it adequately address the interplay between operational issues, CO_2 utilization demand, or CO_2 pipeline capacity (if used as the mode of transportation). Each of these factors is highly relevant to the commercial availability of CCUS for CTs.

- Geographic limitations are not addressed in the Draft White Paper, even though the geographic-specific potential and geologic limitations on sequestration are essential to the discussion of this technology.

- The Class of '85 agrees with EPA that a potential constraint of CCUS use on combined cycle CTs is the reduction in the CT's operating range. Current research and engineering evaluations are focused on addressing this issue, but to date such results have not been demonstrated. If CCUS is required to mitigate CO_2 emissions from CTs, the units would have greatly reduced operating flexibility and would need to operate at a higher capacity factor compared to CTs that are designed to respond to fluctuating power needs.

- Finally, on page 39: the Petra Nova Parish project—a joint project between NRG Energy and JX Nippon—is incorrectly described as being in Washington. It is located in Texas.[17]

6. Oxygen Combustion

Regarding Section 5.8 on oxygen combustion, the technologies that may provide an alternative to the energy-intensive air separation unit ("ASU") have not been demonstrated.

[17] *See, e.g.*, U.S. Department of Energy, Office of Fossil Energy and Carbon Management, *Petra Nova – W.A. Parish Project*, https://www.energy.gov/fecm/petra-nova-wa-parish-project (last accessed June 2, 2022).

The Allam-Fetvedt cycle also is not yet proven. Components have been tested, and subsystems have been demonstrated, but there has yet to be a fully integrated system that can produce more power than it consumes for any meaningful period of time. Further, this technology has yet to be scaled to a commercially useful size. A Class of '85 member currently is supporting EPRI research on the Allam-Fetvedt Cycle. While the technology may ultimately prove effective at reducing GHG emissions, there is a significant amount of additional research and testing required before commercial deployment will be possible. The Group believes that, based on the current state of this research, EPA's estimate that "commercial operations could commence by 2025" is overly optimistic.[18] Further, should testing support large-scale deployment of the technology, it would not be available as a GHG reduction measure until well beyond 2025.

While the Allam-Fetvedt cycle could be considered a CT in that it is an internal combustion engine that transforms chemical energy into shaft power using a turbine, it would more appropriately be classified as a different technology category. First, Allam-Fetvedt is not a "gas turbine" because the working fluid is supercritical and not in a purely gaseous phase. Second, Section 3.2 ties CTs to the Brayton cycle, which is by definition a different heat engine cycle than Allam-Fetvedt. Third, the overall systems (Allam-Fetvedt and Brayton) have a number of other differences such that they are almost as different as CTs are from gas-fired steam units.

7. Hydrogen

The Draft White Paper should discuss how future global hydrogen availability would be affected by the integration of hydrogen at a large scale for new and existing CT EGUs. Currently, hydrogen use is dominated by other industrial processes, such as petroleum refining and ammonia production. This discussion also should address the significant economy-wide investment in expanded infrastructure that would be required for delivery and storage of hydrogen fuels for CTs.

Section 5.9 states that gas-based hydrogen with CCUS may be a method for lowering GHG emissions compared to uncontrolled natural gas-fired CTs. While this seems correct, the same CCUS technology that would be deployed at a hydrogen plant could potentially be deployed at a lower cost if it could be implemented directly at a gas-based power plant; this is because the CCUS technology would be expected to handle approximately 30 percent less flue gas than if deployed at a hydrogen plant.[19] Additionally, the loss in efficiency in the gas-to-hydrogen conversion means that about 30 percent more gas must move through the gas infrastructure, with its associated methane leakages resulting in additional GHG emissions. Ultimately, further cost and efficiency analysis is required before this comparison can be credibly made.

Footnote 59 briefly addresses the fact that potentially higher NOx emissions may result from substantial hydrogen blends or 100 percent hydrogen-fired combustion. The footnote mentions selective catalytic reduction ("SCR") as a potential control measure to address increased NOx but does not address the use of dry low NOx ("DLN") burners with hydrogen combustion. The Group is not sure whether present-day DLN burners can operate successfully with hydrogen-fired CTs while remaining compliant with NOx emission limits; accordingly, EPA should address

[18] Draft White Paper at 41.

[19] However, the flue gas constituents at a hydrogen facility likely would be different enough from flue gas at a natural gas-fired CT that it may not be possible to use total flow as an apples-to-apples comparison without considering other factors. Further analysis is required to support the overall comparison.

this point. In addition, DLN burners used with hydrogen may be susceptible to physical problems like flashback and thermal acoustics. EPA would need to further examine the NOx issue before hydrogen firing can be considered a potentially viable method of mitigating a CT's GHG emissions.

Finally, Section 5.9.1 fails to address the non-GHG emissions caused by combusting ammonia, including most notably NOx.[20]

C. EPA's Consideration of Non-Control Technology Options.

The Class of '85 provides the following feedback on EPA's additional consideration of non-control technologies:

- Section 6.0 and its subsections address upstream GHG emissions; however, the Draft White Paper should further address the impact on GHG emissions from the displacement of geologic natural gas with biogenic alternatives.

- Reciprocating internal combustion engines ("RICE") are not necessarily the primary competitor for simple cycle facilities, as is stated in Section 8.0. When selecting a technology as a new-build scenario, combined cycle facilities can be more competitive or cost effective than either simple cycle CTs or RICE. Electric generators make their selection based on the particular needs to be met and the lifecycle economics while also evaluating factors such as reliability and risks.

III. CONCLUSION

The Class of '85 appreciates EPA's consideration of its comments on the Draft White Paper. The Group encourages EPA to reassess and revise the Draft White Paper in consideration of these comments and requests that further analysis of technologies be conducted in support of the final White Paper. These changes are necessary to ensure that any final White Paper that provides the basis for future decision making adequately analyzes the feasibility, availability, costs, and benefits of the technologies considered by EPA.

Importantly, because of the extent to which the Group believes EPA should update and expand its research and analysis, the Group urges EPA to provide an opportunity for public notice and comment on a revised version of the Draft White Paper.

Finally, while the White Paper represents a snapshot of the current state of CT technologies and control options, to the extent EPA or other agencies plan to rely on information in the White Paper in future rulemakings or permitting actions, the analysis in the White Paper must be supplemented with the most up-to-date information and research then available—including engagement with relevant stakeholders.

[20] *See, e.g.*, Hideaki Kobayashi et al., *Science and Technology of Ammonia Combustion*, 37 PROCEEDINGS OF THE COMBUSTION INSTITUTE 1 (Jan. 25, 2019), https://www.sciencedirect.com/science/article/pii/S1540748918306345.

Dated: June 6, 2022

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Attachment A

AES Corporation
Alliant Energy Corporation
Ameren
Arizona Public Service
Arizona Electric Power Cooperative, Inc.
Arkansas Electric Cooperative Corporation
City of Tallahassee
Cleco Corporation
Cogentrix Energy Power Management, LLC
Dairyland Power Cooperative
Dayton Power & Light Company
Dominion Energy
Duke Energy
Entergy Services, LLC
Evergy, Inc.
Florida Municipal Electric Association
Gainesville Regional Utilities
Great River Energy
Hawaiian Electric Company, Inc.
Indianapolis Power & Light Company
JEA
Lakeland Electric
Louisville Gas & Electric/Kentucky Utilities
Minnesota Power
National Grid
NRG Energy
OGE Energy Corp.
Orlando Utilities Commission
PowerSouth Energy Cooperative
Public Service Company of New Mexico
Salt River Project
Talen Energy
Tampa Electric Company
Tucson Electric Power Company
Western Farmers Electric Cooperative
Xcel Energy Inc.

Attachment C

Class of ’85 comments on EPA’s proposed rule

Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations under Clean Air Act

Dkt ID. No. EPA-HQ-OAR-2021-0527-0093

COMMENTS OF THE CLASS OF ’85 REGULATORY RESPONSE GROUP

ON THE

ADOPTION AND SUBMITTAL OF STATE PLANS FOR DESIGNATED FACILITIES: IMPLEMENTING REGULATIONS UNDER CLEAN AIR ACT SECTION 111(d)

EPA Docket No. EPA-HQ-OAR-2021-0527

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I. INTRODUCTION

On December 23, 2022, the U.S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 87 Fed. Reg. 79,176, a proposed rule: *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Clean Air Act Section 111(d)* ("Proposed Rule"). The Proposed Rule would amend the regulations codified at 40 C.F.R. Part 60, Subpart Ba, which govern the processes and timelines for state and federal plans that implement emission guidelines ("EGs") promulgated by the Agency under Section 111(d) of the Clean Air Act ("Implementing Regulations"). Among other measures, the Proposed Rule would address presumptive timing and review requirements for state and federal plan development, public participation requirements for state plan development, the availability of trading and averaging mechanisms to demonstrate compliance with standards of performance, and flexibility for states to impose standards of performance for particular facilities or classes of facilities that are either more or less stringent than the presumptive level of stringency in the applicable EG.

The Class of '85 Regulatory Response Group ("Class of '85" or "Group") respectfully submits these comments on the Proposed Rule.[1] The Class of '85 is a voluntary, ad hoc coalition of over 40 electric generating companies from across the country that has been actively involved in the development and implementation of Clean Air Act rules affecting the electric generating industry for more than 30 years. The Group has a particular interest in the Proposed Rule because EPA is in the process of developing a Section 111(d) rulemaking for existing electric generating units ("EGUs"). Class of '85 members own and operate EGUs throughout most of the United States and collectively generate a significant portion of the country's electricity. Because EPA anticipates issuing proposed EGs for greenhouse gas ("GHG") emissions from existing fossil-fuel fired EGUs later this year,[2] members of the Class of '85 would be directly affected by the finalization of this Proposed Rule.

II. COMMENTS

The Class of '85 supports certain aspects of the Proposed Rule but has suggestions for modifications that the Agency should make to other aspects of the Proposed Rule. The Group is mindful of the fact that EPA seeks to revise the state plan deadlines that were vacated by the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in *American Lung Association v. EPA*, 985 F.3d 914 (D.C. Cir. 2021). However, the Group believes that the Proposed Rule does not establish realistic presumptive timelines for developing, processing, and implementing proposed state plans. Additionally, the Class of '85 is concerned that certain aspects of the Proposed Rule are outside the scope of EPA's authority under Section 111(d) of the Clean Air Act.

[1] Attachment A contains a list of the Class of '85 members supporting these comments.

[2] *See* Fall 2022 Unified Agenda of Regulatory and Deregulatory Actions, Emission Guidelines for Greenhouse Gas Emissions From Fossil Fuel-Fired Existing Electric Generating Units, RIN 2060-AV10 (Jan. 4, 2023), https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202210&RIN=2060-AV10.

A. The Class of '85 Supports EPA's Proposal to Retain Flexibility in Establishing and Implementing Standards of Performance.

1. The Class of '85 supports EPA's proposal to retain the provisions allowing the Agency to supersede the Implementing Regulations for specific EGs.

EPA is proposing to retain 40 C.F.R. § 60.20a(a)(1), which allows specific EGs to supersede the presumptive timelines for state plans to "address unusual circumstances or facts that are not accommodated by the general provisions" based on "the needs of a specific EG."[3] In addition, EPA is proposing to modify § 60.27a(a) to allow the Agency not only to shorten, but also to extend, the presumptive timelines for submitting state plans and state plan revisions.[4] The Class of '85 supports these proposals, as sector-specific factors may impact the timing of plan development and compliance in ways that make the presumptive requirements too constraining. Many sectors, including the electric generating industry, face unique challenges that would complicate the development of state plans, which in turn would impact compliance with the default timing requirements. Retaining EPA's flexibility to modify the default requirements would result in EGs and state plans that are better tailored to the affected source category.

This flexibility is consistent with the D.C. Circuit's decision in *American Lung Association*. There, the D.C. Circuit held that EPA must consider all "important aspect[s] of the problem" in setting state planning deadlines,[5] consistent with the U.S. Supreme Court's decision in *Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance Co.*, 463 U.S. 29, 43 (1983). The D.C. Circuit explicitly recognized that certain factors could impact EPA's determination of a reasonable deadline, such as administrative burdens and statutory considerations like consistency with Clean Air Act Section 110.[6]

It is appropriate for state plan submittal deadlines to be tailored to the circumstances that will impact state plan development. Preventing the Agency from accounting for sector-specific factors when setting each EG's plan deadlines would unreasonably interfere with states' implementation of Section 111(d). Unattainable deadlines could result in states failing to submit approvable plans on time, thus triggering EPA's obligation to develop federal plans.[7] Because Section 111(d) explicitly allocates authority for its implementation to the states in the first instance, an unreasonable state plan submittal deadline could have the effect of improperly transferring that authority to EPA by making it inevitable that the Agency will develop federal plans. Forcing states to rush to develop their plans also increases the risk that EPA's approval of plans may be more vulnerable to legal challenge and may not allow time for meaningful engagement with pertinent stakeholders and economic regulators. If state plan implementation is stayed during a legal challenge, the time needed to achieve actual emission reductions would be extended. This could lead to "added environmental and public health damage . . . from slowing down the entire Section

[3] Proposed Rule, 87 Fed. Reg. at 79,181.
[4] *See id*. at 79,209; 40 C.F.R. § 60.27a(a) in Redline Strikeout of Proposed 111(d) Implementing Regulations, Docket ID No. EPA-HQ-OAR-2021-0527-0002 (Dec. 6, 2022) (hereinafter "Redline") (proposing to replace "shorten" with "amend").
[5] *Am. Lung Ass'n*, 985 F.3d at 993.
[6] *See id*. at 993.
[7] *See* 40 C.F.R. § 60.27a.

[111(d)] regulatory process"—the very concern identified by the D.C. Circuit when it vacated EPA's prior state plan submittal deadline.[8]

2. The Class of '85 supports EPA's proposed interpretation of Section 111(d) as granting states the discretion to determine the best form of compliance to meet the standards of performance under each EG, including through trading or averaging.

EPA is proposing to amend the regulatory definition of "standard of performance" to explicitly clarify that states may adopt measures that allow sources to meet their emission limits in the aggregate, including through trading or averaging.[9] The Agency proposes to interpret Section 111 to "permit[] each state to adopt measures that allow its sources to meet their emission limits in the aggregate, when the EPA determines, in any particular emission guideline, that it is appropriate to do so, given, inter alia, the pollutant, sources, and standards of performance at issue."[10] To implement this interpretation, EPA proposes to modify the regulatory definition of "standard of performance" to add "quantity, or concentration" of emissions, which clarifies that states could be allowed to use mass-based limits for compliance with an EG.[11] The Class of '85 supports this clarifying change because it is consistent with the compliance flexibility allotted to the states under Section 111(d). For the same reason, the Group also supports EPA's proposal to reverse "the ACE Rule's conclusion that state plan compliance measures must always correspond with the approach the EPA uses to set the [best system of emission reduction], where the environmental outcomes of the emissions guidelines are not compromised by a lack of alignment."[12]

Section 111(d) tasks EPA with determining which emission reduction measures have been adequately demonstrated as the best system of emission reduction ("BSER"), and then allows each State to determine in the first instance how best to apply the BSER to set emissions standards within its domain.[13] The state's role includes not only the establishment of the standards of performance for sources within the state's jurisdiction, but also the determination of how compliance with these standards will be achieved. States are in the best position to design, implement, and enforce the substantive requirements of Section 111(d). For example, with respect to the development of state plans for EGUs, states understand their unique energy resources, the state and local laws governing those resources, and how to account for and manage relationships with system operators, state economic regulators, regional transmission organizations, and the Federal Energy Regulatory Commission.

Section 111 recognizes the role of state air agencies as primary regulators by affording them additional flexibility in developing state plans. For instance, Section 111(d) requires EPA to provide states with the flexibility to consider the remaining useful life of the source and "other factors" ("RULOF") when applying a standard of performance.[14] The flexibility in Section 111(d)

[8] *Am. Lung Ass'n*, 985 F.3d at 993.
[9] *See* Proposed Rule, 87 Fed. Reg. at 79,206–07; Redline § 60.21a(f).
[10] Proposed Rule, 87 Fed. Reg. at 79,208.
[11] Redline § 60.21a(f).
[12] Proposed Rule, 87 Fed. Reg. at 79,208.
[13] *See Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2539 (2011).
[14] *See* 42 U.S.C. § 7411(d)(1).

mirrors that of other programs, such as Section 169A's Regional Haze program,[15] where states develop their own plans for implementing Clean Air Act requirements, and EPA must approve or disapprove the states' plans. For the first planning period of the Regional Haze program, state plans were required to implement the best available retrofit technology ("BART") at any source found to cause or contribute to visibility impairment, but states developed their own determination of what constituted source-specific BART—which was then subject to EPA approval. The Regional Haze regulations specifically authorized states to satisfy the source-specific application of BART through "an emissions trading program or other alternative."[16] States also were required to take the remaining useful life of the source into account in establishing BART.[17]

Retaining flexibility for states to pursue appropriate compliance measures is critically important for many sectors. The electric generating sector, for example, is subject to operational challenges that impact the applicability and implementation of standards of performance. Unlike other source categories, the decision of whether and how much to operate an EGU may be determined by a system operator instead of by the unit's owner or operator. As a result, depending on a facility's role in the integration of renewable resources, weather conditions, and other factors, a fossil fuel-fired EGU's operating mode could fluctuate between peaking, load following, and baseload—all within a short period of time. These fluctuations directly impact both the emission rate and total amount of carbon dioxide ("CO_2") emitted by a unit and underscore the need for tailored state plans. It is therefore important for states to retain flexibility to consider various factors in crafting their state plans, which, for fossil fuel-fired EGUs, include but are not limited to the costs of service, voltage support, electricity demand, availability of renewable resources, and which types of generating resources best satisfy the need for generation capacity, energy, and ancillary services.

In *West Virginia v. EPA*, 142 S.Ct. 2587 (2022), the U.S. Supreme Court did not opine on the appropriate scope of either BSER or state compliance flexibilities under Section 111.[18] As to BSER, the Court stated that it had "no occasion to decide whether the statutory phrase 'system of emission reduction' refers *exclusively* to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as the BSER."[19] As to compliance mechanisms, the Court did not endorse a particular approach; it looked to the now-defunct Clean Air Mercury Rule ("CAMR")[20] as an example of a Section 111(d) trading program that was distinct from the generation-shifting approach in the Clean Power Plan, but it did not determine whether CAMR was legally valid under Section 111(d).[21] Without specific direction from Congress or the courts to the contrary, EPA should leave the determination of appropriate compliance flexibilities to each state's discretion. This approach is consistent with the Clean Air

[15] *See id.* § 7491.
[16] 40 C.F.R. § 51.308(e).
[17] *See* 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e); *id.* at Part 51, Appendix Y.
[18] Although the Court did not define what constitutes the appropriate scope of BSER, it did identify the Clean Power Plan's generation-shifting approach as an example of a BSER determination that was definitively *outside* of the scope of EPA's Section 111(d) authority. *See West Virginia v. EPA*, 142 S.Ct. at 2615–16 ("[T]he only interpretive question before us, and the only one we answer, is more narrow: whether the 'best system of emission reduction' identified by EPA in the Clean Power Plan was within the authority granted to the Agency in Section 111(d) of the Clean Air Act. For the reasons given, the answer is no.").
[19] *Id.* at 2615.
[20] *See* 70 Fed. Reg. 28,606 (May 18, 2005). CAMR was vacated by *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008) on grounds that are unrelated to the discussion in these comments.
[21] *See* 142 S.Ct. at 2610–11 n.1 and accompanying text.

Act's emphasis on state primacy and the Supreme Court's holding that EPA's authority to determine the BSER is limited by what Congress has clearly authorized in the statute. Accordingly, the Class of '85 agrees with EPA that averaging and trading are allowable compliance mechanisms under Section 111.[22]

EPA's preservation of compliance flexibilities in the Implementing Regulations does not rise to the level of a "major question," in contrast to the generation-shifting approach that the Court rejected in *West Virginia*. EPA has a long history of overseeing trading under the Clean Air Act's "good neighbor" provision.[23] Since 2011, EPA has administered a regional emissions trading program through the Cross-State Air Pollution Rule ("CSAPR").[24] In April 2022, EPA proposed an expanded CSAPR program that would require fossil fuel-fired power plants in 25 states to participate in an allowance-based ozone season trading program beginning this year.[25] States also have a history of relying on trading programs to achieve emission reductions through both state-specific schemes and regional programs, such as the Regional Greenhouse Gas Initiative ("RGGI").[26] Retaining state flexibility to pursue a broad range of compliance measures is consistent with the Supreme Court's decision in *West Virginia* and appropriately recognizes each state's primacy and discretion in determining how best to achieve emission standards within its own domain.

B. The Class of '85 Urges EPA to Adopt Presumptive State Plan Timing Requirements that Are Attainable.

In *American Lung Association*, the D.C. Circuit held that EPA failed to consider public health and welfare impacts in revising the state plan deadlines in the Implementing Regulations.[27] Specifically, the court determined that the Agency could not merely adopt the deadlines in Section 110, but rather must "engage meaningfully with the different scale of the two types of plans" and consider the effect of "prolonging public exposure to ongoing harms from pollutants emitted by existing source categories."[28] The court emphasized that EPA could not "entirely fail" to consider public health and welfare in setting state planning deadlines,[29] but recognized that administrative burdens may justify a longer timeframe for plan development.[30]

On remand from the D.C. Circuit, EPA is now proposing to update the presumptive timelines governing state and federal Section 111(d) plan development based on what the Agency believes is "the minimum administrative time reasonably necessary for each step in the

[22] Proposed Rule, 87 Fed. Reg. at 79,208.
[23] *See* 42 U.S.C. § 110(a)(2)(D)(i).
[24] *See* Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208 (Aug. 8, 2011); Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 81 Fed. Reg. 74,504 (Oct. 26, 2016).
[25] *See* Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20,036 (Apr. 6, 2022).
[26] *See* Brief for State of New York and Other State and Municipal Respondents, *West Virginia v. EPA*, No. 20-1530, at 27 (filed Jan. 18, 2022).
[27] *See Am. Lung Ass'n v. EPA*, 985 F.3d 914 (D.C. Cir. 2021).
[28] *Id.* at 993–94.
[29] *Id.* at 994.
[30] *See id.* at 993.

implementation process."[31] However, EPA's proposed timelines are not reasonable because they are not realistic predictions of how long it will take for states and the Agency to fulfill their respective obligations under Section 111(d). EPA should lengthen the proposed deadlines to ensure that states have sufficient time to develop robust, legally sound plans while satisfying EPA's proposed meaningful public engagement requirements; that the Agency has sufficient time to review and approve such plans or, when necessary, develop a federal plan; and that there is sufficient time for designated facilities to come into compliance with those plans.

1. EPA should extend deadlines for state plan submissions and revisions to ensure that states have sufficient time to develop legally defensible plans while securing meaningful public engagement.

EPA's proposed default timeline for state plan submittal is 15 months after the effective date of an EG.[32] According to EPA, "15 months should adequately accommodate the differences in state processes necessary for the development of a state plan that meets applicable requirements."[33] However, this default timeline does not sufficiently account for analytical and administrative challenges that impact the state planning process. Ensuring that states have sufficient time to develop legally defensible plans is critical to EPA's goals of protecting public health and welfare and ensuring expeditious action to implement emission guidelines, consistent with the D.C. Circuit's decision in *American Lung Association*. For the reasons detailed below, the Class of '85 recommends that EPA lengthen the presumptive state plan submission deadline that will apply to future EG rulemakings. For example, a default deadline of 18 months from the effective date of an EG, with the option for states to request a deadline extension of up to 12 months on a case-by-case basis, might be more appropriate. Alternatively, EPA should consider a longer default timeframe, such as 24 to 36 months from the EG effective date, and can use the Agency's superseding authority in 40 C.F.R. § 60.20a(a)(1) to shorten individual EG timeframes when appropriate. In addition, the deadline for submitting state plan revisions in response to a revised EG should mirror the deadline for developing initial state plans.

(i) Fifteen months is an unrealistic state plan development timeframe based on current regulatory requirements.

Given all of the considerations that must go into state plan development, EPA's proposed default deadline for submitting Section 111(d) state plans is insufficient. It fails to take into account the states' decision-making processes, as described in this section.

State air agencies need time to develop proposed state plans before the plans are ready to proceed through the state's administrative process. This is no small task, as it requires an in-depth evaluation of each designated facility within the agency's jurisdiction. Due to lean budgets and understaffed agencies, many states do not have the resources or expertise to conduct this entire evaluation "in house" and will need to work with outside technical specialists, economists, and the regulated entities themselves to comprehensively evaluate all of the sources in an affected source category and come up with an appropriate standard of performance considering RULOF, as well as a compliance schedule each source to achieve the standard. For the regulated entities, this often

[31] Proposed Rule, 87 Fed. Reg. at 79,181.
[32] *See id.* at 79,181–82.
[33] *Id.* at 79,183.

requires working with outside consultants to come up with recommendations to provide to the agencies. Significant lead time is required to properly sequence these efforts before an air agency can begin drafting a proposed state plan. And, as discussed further below, the Proposed Rule would require robust involvement from stakeholders in developing a state plan, so the state agency may need to engage with additional outside parties before the plan is ready for public comment.

States also need sufficient time to take their plans through the applicable administrative rulemaking processes, which includes the opportunity for public comment, responding to public comments, and revising the proposed state plan accordingly. In some cases, legislative approval of a state plan is required before the plan can be submitted to EPA. The original nine-month timeframe for state plan submittals was promulgated in 1975, making it nearly 50 years old. Much has changed since 1975, starting with the Clean Air Act itself via significant amendments in 1977 and 1990. There also has been an increase in the extent of administrative process requirements in many states, as described below. Further, the impacts of environmental regulation have become more complicated, particularly for the electric generating industry. There are more ways to generate electricity, more customers, and more details that must be considered when contemplating a change to an EGU to decrease its emissions as compared to the state of the industry in 1975. The economy also has become more complex, making it more difficult to assess the economic implications of a proposed standard of performance when developing a state plan. States have had to become more sophisticated in identifying and assessing impacts to stakeholders, as is evident by the increasing focus on environmental justice as a fundamental consideration at all levels of environmental rulemaking. In short, 15 months from the EG effective date is an insufficient timeframe for most, if not all, states to be able to develop a state plan.

EPA acknowledges in its Proposed Rule that state administrative processes are likely to significantly affect planning timelines.[34] Specifically, EPA notes that, "[i]n many states, the agency must submit its rule to a particular independent commission or the legislature for review and approval before the rule is finally adopted."[35] Despite acknowledging this in the preamble, the Proposed Rule does not adequately account for such processes. In the starkest case, some states that require legislative review of regulations—for example, Montana[36] and Nevada[37]—have legislatures that do not meet in session every year, leading to an even lengthier legislative approval process.[38] Depending on when an EG is finalized by EPA within the legislative cycle, these states may not be able to secure the requisite legislative approval in time to meet a 15-month state plan submission deadline. The Class of '85 offers the following additional examples from states that have legislative and/or other administrative approval processes and requirements that would make

[34] *See id.* at 79,182–84; *see also id.* at 79,184 ("EPA acknowledges that there are a number of individual state-specific factors that can affect the amount of time required for the development and submission of state plans.").
[35] *Id.* at 79,182 n.9.
[36] *See* Mont. Code Ann. 2021 § 2-4-402 ("The administrative rule review committees shall review all proposed rules filed with the secretary of state.").
[37] *See* Office of the Nevada Attorney General, *Administrative Rulemaking: A Procedural Guide* at 38 (Mar. 2014), https://ag.nv.gov/uploadedFiles/agnvgov/Content/Publications/RulemakingManualComplete.pdf ("Pursuant to NRS 233B.067, the Legislative Commission must review the regulation to determine whether to approve it, and the Legislative Commission must approve the regulation before it becomes effective.").
[38] *See* National Conference of State Legislatures, *Legislative Session Length* (July 1, 2021), https://www.ncsl.org/news/details/legislative-session-length (listing Montana, Nevada, North Dakota, and Texas as having biennial legislative sessions).

a 15-month presumptive deadline infeasible—even for states that begin working diligently on their plans from the moment the EG is finalized. Group members operate in each of these five states:

- **Arkansas** requires rules developed by administrative agencies, including the Arkansas Division of Environmental Quality ("ADEQ"), to be reviewed and approved by a legislative committee prior to finalization. An ADEQ guidance document provides estimated minimum timeframes for some (but not all) of the steps in the rulemaking process.[39] ADEQ's *minimum* estimate for just *part* of its rulemaking process is roughly 12 months. Typically, ADEQ spends nearly 15 months gathering source-specific information and conducting a technical evaluation to inform a proposed plan, which means that a 15-month timeline for finalizing a Section 111(d) state plan submittal would severely curtail ADEQ's process for developing a plan. In addition, Arkansas has a statutory provision that specifically addresses the development of a Section 111(d) state plan for regulating GHG emissions from fossil-fuel fired EGUs.[40] This provision establishes a number of additional procedures that ADEQ must follow for a state plan for EGU GHG emissions, including preparing a report—which must be completed *before* the public comment period on the state plan[41]—that addresses the impacts of the proposed state plan on 16 statutory factors, including the availability of air-cleaning devices, economic feasibility of air-cleaning devices, effect on efficiency of industrial operation resulting from use of air-cleaning devices, the economic and industrial development of the state, and the social and economic value of the air contamination sources.[42] Under the timing EPA has proposed, it would be extremely difficult for Arkansas to timely develop an appropriate state plan that complies with an EG for EGU GHG emissions because of the state's additional procedures.

- **Colorado** has a robust environmental justice statute that requires comprehensive outreach and engagement with "disproportionately impacted communities" during the rulemaking process,[43] as well as a legislative approval requirement for regulations.[44] Because of the scope and depth of effort required to meet these statutory obligations, which is a time-consuming process,[45] Colorado has routinely missed deadlines to submit Clean Air Act

[39] *See* Arkansas Division of Environmental Quality, *DEQ Rulemaking Process*, https://www.adeq.state.ar.us/water/planning/reg2/triennial/pdfs/deq-rulemaking-process.pdf (last accessed Jan. 30, 2023).
[40] *See* Ark. Code Ann. §§ 8-3-201 to -208.
[41] *Id.* § 8-3-205.
[42] *See id.* § 8-4-312.
[43] *See* Colorado Environmental Justice Act, HB21-1266 (signed into law on July 2, 2021), https://leg.colorado.gov/sites/default/files/2021a_1266_signed.pdf.
[44] *See* C.R.S.A. § 25-7-133.
[45] For example, in materials provided for a December 2022 Colorado Air Quality Control Commission ("AQCC") hearing on state implementation plans ("SIP") addressing ozone, Colorado's Air Pollution Control Division and Regional Air Quality Council jointly described the lengthy stakeholder engagement process undertaken for the development of proposed SIP revisions. *See* Joint Prehearing Statement at 3; Joint Memorandum of Notice at 22–24. Instructions for accessing these materials online are as follows: (1) Visit AQCC's website for current and recent commission hearings at https://cdphe.colorado.gov/aqcc-current-and-recent-commission-hearings; (2) Click the link for "Rulemaking Hearing: Ozone SIP, Regulation Numbers 3, 7, 21, Common Provisions, and Air Quality Standards, Designations, and Emission Budgets, December 13–16, 2022," which will bring up a Google Drive; (3) For the Joint Prehearing Statement, take the following path: 06_Prehearing Statements > JOINT Air Pollution Control Division & Regional Air Quality Council > APCD-RAQC_PHS.pdf; (4) For the Joint Memorandum of Notice, take the following path: 01_Request for Hearing > Memorandum of Notice_Sept 2022.pdf.

plans to EPA.[46] In addition to these existing requirements, the Colorado Air Pollution Control Division plans to propose a rule in May 2023 that could add "requirements for existing sources of pollution within disproportionately impacted communities."[47] It is possible that these additional requirements would add to the time it takes Colorado to develop a state plan, depending on what ultimately is required for existing sources once this rulemaking is finalized.[48]

- **Florida** requires legislative review of regulations via the state's Joint Administrative Procedures Committee ("JAPC").[49] The JAPC decides on a case-by-case basis whether a public hearing must be held on a proposed rule; because this process is not routine, a Florida agency may not be able to predict how long it will take for the JAPC to complete its review of a proposed rule. This process has sometimes delayed Florida's development of Clean Air Act submittals to EPA.

- **Mississippi** law prohibits the Mississippi Department of Environmental Quality ("MDEQ") from implementing an environmental regulation that is more stringent than what is required by EPA regulations and requires that state regulations be consistent with federal statutes, regulations, criteria, and guidance.[50] This means that Mississippi's proposed state plan must essentially incorporate an EG into state regulations. MDEQ informed a Mississippi-based Group member that it expects to need at least six months to conduct the required public engagement, followed by at least 12 months to draft the state plan and proceed through the rulemaking process, followed by at least six months to obtain approval from the Mississippi Secretary of State before the regulation could take effect no sooner than 30 days later.[51] Accordingly, MDEQ estimates that it would need at least 24 months to prepare a state plan submittal.

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[46] *See, e.g.*, *WildEarth Guardians v. Regan*, 591 F. Supp. 3d 995, 998 (D. Colo. 2022) (serious nonattainment area SIP for the 2008 ozone NAAQS was due August 3, 2020; submitted by Colorado on March 22, 2021); Interstate Transport Prongs 1 and 2 for the 2010 Sulfur Dioxide (SO_2) Standard for Colorado, Montana, North Dakota, South Dakota and Wyoming, 83 Fed. Reg. 25,617 (June 4, 2018) (2010 SO_2 interstate transport SIP elements due June 2, 2013; Colorado submitted a portion of required SIP on February 16, 2018); Clean Air Act Approval and Promulgation of PM_{10} Implementation Plan for Denver, CO, 62 Fed. Reg. 18,716, 18,717 (Apr. 17, 1997) (moderate nonattainment area SIP revisions for 1987 PM_{10} NAAQS due by November 15, 1991; submitted by Colorado on June 7, 1993).

[47] Colorado Air Pollution Control Division, *Disproportionately Impacted Community Permitting Rulemaking*, https://cdphe.colorado.gov/disproportionately-impacted-community-permitting-rulemaking/normas-de-permisos-para-las-comunidades (last accessed Jan. 30, 2023).

[48] For example, if the new rule requires the Air Pollution Control Division to conduct more extensive analysis of sources in disproportionately impacted communities when establishing an emission standard, it would add an additional step in the already lengthy process that Colorado has to undertake for state plan development.

[49] *See* Florida Administrative Law Central Online Network, *About the Joint Administrative Procedures Committee*, https://www.japc.state.fl.us/Pages/About.aspx (last accessed Jan. 30, 2023).

[50] *See* Miss. Code Ann. § 49-17-34(2) ("All rules, regulations and standards relating to air quality, water quality or air emissions or water discharge standards promulgated by [MDEQ] after April 16, 1993 shall be consistent with and shall not exceed the requirements of federal statutes and federal regulations, standards, criteria and guidance relating to air quality, water quality or air emission or water discharge standards that have been duly promulgated pursuant to the federal Administrative Procedures Act, including but not limited to the identity and scope of air pollutants included as air toxics or air quality or emission standards, the identity and scope of water pollutants included as water quality or discharge standards and the numerical and narrative limitations of such standards.").

[51] *See* Miss. Code. Ann. § 25-43-3.113(1) ("each rule adopted after July 1, 2005, becomes effective thirty (30) days after its proper filing in the Office of the Secretary of State").

- **Oklahoma** requires Section 111(d) state plans to go through a lengthy review process; plans must be approved by the state's Air Quality Advisory Council ("AQAC"), Environmental Quality Board ("EQB"), governor, and legislature prior to their official adoption and submittal to EPA.[52] Once a proposed rule is developed by the Oklahoma Department of Environmental Quality ("ODEQ"), the proposal undergoes public comment and AQAC review at quarterly meetings—and proposed rules typically go through more than two AQAC meetings. After all public comments have been addressed, which may require multiple rounds of revisions to the proposed rule, the AQAC must vote to recommend the proposed rule to the EQB. The EQB either approves the proposed regulation and sends it to the governor or sends revisions back to the AQAC. Because the EQB historically meets only twice a year, in February and September, ODEQ cannot control the timing of this part of the process. Eventually, the proposed rule is sent to the governor, who must approve the proposal before it is sent to the legislature for approval. If the proposed rule is not approved by the end of the legislative session in May, the proposal will go back to the governor for final adoption. Finally, regardless of the manner of final approval, all final rules in Oklahoma have a September effective date. A 15-month timeline would be extremely tight, if not impossible, for Oklahoma's development of a state plan.

Even if a 15-month default deadline were appropriate, EPA has not properly supported it in the Proposed Rule. For example, the Agency notes that, for areas designated as nonattainment for a national ambient air quality standard ("NAAQS") for particulate matter ("PM"), Section 189(a)(2)(B) of the Clean Air Act requires SIPs to be submitted to EPA within 18 months of the nonattainment designation.[53] The Proposed Rule goes on to say that, because state plans under Section 111(d) are less complex than PM NAAQS nonattainment SIPs under Section 189, the deadline for Section 111(d) state plans should be shorter than 18 months.[54] However, even if that observation were true, EPA fails to examine whether states consistently meet that 18-month deadline, and, in the experience of Class of '85 members, it generally takes longer than 18 months to develop and submit a NAAQS SIP.[55] There is nothing in the Clean Air Act that requires Section

[52] *See* Okla. Stat. Ann. tit. 27A § 2-5-107 (describing the function of AQAC); *id.* § 2-2-101(H) (describing the function of EQB); Okla. Stat. Ann. tit. 75 § 303 (authorizing the governor to disapprove proposed rules); *id.* § 308 (authorizing legislative approval or disapproval of rules).

[53] *See* 42 U.S.C. § 7513a(a)(2)(B).

[54] *See* Proposed Rule, 87 Fed. Reg. at 79,183.

[55] In fact, states often need significantly longer than 18 months for state plans under the NAAQS and other programs. For example, in 2017, EPA extended the submission deadline for regional haze second planning period SIPs by three years, from July 2018 to July 2021. *See* Protection of Visibility: Amendments to Requirements for State Plans, 82 Fed. Reg. 3078 (Jan. 10, 2017). EPA explained that this extension would "allow states to coordinate regional haze planning with other regulatory programs" and "lead to better overall policies and enhanced environmental protection." *Id.* at 3117. But even with the three-year extension, as of April 2022, 34 states had not met the submission deadline. *See* Complaint for Declaratory and Injunctive Relief, *Sierra Club v. EPA*, No. 22-2302 (N.D. Cal. filed Apr. 13, 2022). States have faced similar challenges under the interstate transport program for the ozone NAAQS. Section 110(a)(2)(D)(i)(I) of the Clean Air Act imposes a three-year deadline to submit SIPs that address the obligation to prohibit in-state sources from contributing significantly to nonattainment or interfering with maintenance of a NAAQS in any other state. *See* 42 U.S.C. § 7410(a)(2)(D)(i)(I). EPA amended the 8-hour ozone NAAQS in October 2015, requiring states to submit SIP revisions by October 2018. *See* National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65,292 (Oct. 26, 2015). However, as of December 2019—over one year after the three-year deadline—seven states had not submitted complete SIPs due to the complexity of assessing their obligations under this program.

111(d) state plan deadlines to be shorter than what the statute establishes for NAAQS SIPs. EPA has the authority to set identical or even *longer* deadlines for Section 111(d) state plans provided that the Agency sufficiently justifies why the longer deadlines are necessary and considers "the public health and welfare implications of the extended timeframes," as the D.C. Circuit held in *American Lung Association*.[56] Additionally, EPA's analysis in the preamble actually cuts *against* the proposed 15-month deadline. The Agency notes that Section 111(d) plans "could involve more complicated analyses" than Section 129 plans, yet EPA has proposed a Section 111(d) plan deadline that is on the shorter end of the 14-to-17-month range in which a "significant number of states" submitted Section 129 plans.[57] Quite simply, EPA's analysis is illogical and, in any event, is insufficient to meet the requirements set out in *American Lung Association*.

(ii) Fifteen months is an unrealistic state plan development timeframe in light of the proposed public participation requirements.

EPA is proposing to increase public participation in the state plan development process by requiring states to demonstrate "meaningful engagement" and identify "pertinent stakeholders," yet the Agency also is proposing to decrease the amount of time that was provided for state plan development in Subpart Ba prior to the D.C. Circuit's vacatur.[58] The Class of '85 is concerned that EPA's proposed deadline for state plan submittals does not provide states enough time to satisfy the proposed public participation requirements. The Agency acknowledges in the Proposed Rule that enhanced public participation procedures likely will impact planning timelines[59] but provides little guidance as to the types of procedures that would fulfill these enhanced requirements and does not quantify how such procedures will affect the time needed to develop Section 111(d) plans. States may be required to engage with pertinent stakeholders both inside *and outside* of the borders of the state[60] and they also may wish to pursue alternative state procedures for public participation that first must be approved by EPA.[61] Colorado's experience implementing its environmental justice statute demonstrates that adding public participation requirements to the rulemaking process adds to the overall timeline for agency action.[62] EPA should provide states sufficient time to develop plans that can satisfy the proposed public engagement requirements.

See Findings of Failure To Submit a Clean Air Act Section 110 State Implementation Plan for Interstate Transport for the 2015 Ozone National Ambient Air Quality Standards, 84 Fed. Reg. 66,612 (Dec. 5, 2019).

[56] *Am. Lung Ass'n*, 985 F.3d at 992.

[57] Proposed Rule, 87 Fed. Reg. at 79,183.

[58] *See id.* at 79,190–91.

[59] *See id.* at 79,184 ("[T]he time needed to conduct meaningful engagement will be highly dependent on the number and location of designated facilities addressed by an EG, as well as on the type of health or environmental impacts of the associated emissions.").

[60] *See id.* at 74,830.

[61] *See id.*

[62] *See supra* at 8–9.

(iii) Fifteen months is an unrealistic state plan development timeframe in light of the proposed expansion of RULOF analyses required for establishing source-specific standards of performance.

Section 111(d)(1) directs EPA to promulgate regulations that allow states to account for RULOF for a particular source in setting individualized standards of performance.[63] EPA is proposing to require states to undertake a more extensive analysis when setting a source-specific standard of performance.[64] As explained in greater detail in Section II.D. of these comments, the Class of '85 believes that EPA's proposal to restrict states' consideration of RULOF in setting standards of performance is inconsistent with the Agency's statutory authority under Section 111(d). The Group also is concerned that EPA's proposed state submittal deadline fails to account for the added burdens associated with its proposed RULOF process, effectively precluding states from being able to take RULOF into account and timely submit plans.

In its recent supplemental proposal to "update, strengthen, and expand" the Agency's proposed EGs for GHG emissions from the oil and natural gas sector, EPA acknowledges that both public engagement requirements and consideration of RULOF are likely to impact the state plan development timeline.[65] Accordingly, EPA has proposed to give states 18 months to develop state plans for existing oil and gas facilities. And yet, in the Proposed Rule, EPA asserts that "the timelines proposed in these implementing regulations represent what the EPA has determined will be necessary for the implementation of most EGs."[66] It is not clear from this Proposed Rule why states would need more than 15 months to address RULOF considerations for the oil and gas source category but not for most other source categories as well. Failing to provide a sufficient default time for the plan development process could result in states being unable to adequately account for RULOF. Not only does this effectively prohibit states from being able to sufficiently consider RULOF as authorized under Section 111(d),[67] it also could make the plans susceptible to legal challenge, thereby delaying implementation and creating regulatory uncertainty for designated facilities, state agencies, and other stakeholders.

Although the Class of '85 recognizes that EPA is proposing to allow a specific EG to supersede the default 15-month state plan deadline, this is an insufficient remedy. EPA will have to justify in a specific EG any deviation from the default deadline, which could then be subject to legal challenge, thereby leading to uncertainty as to when the state plans would be due in light of the pending litigation. EPA should instead provide a longer default deadline to limit the circumstances under which it will need to supersede that default deadline in a specific EG, and can shorten specific deadlines using its superseding authority.

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[63] *See* 42 U.S.C. § 7411(d) ("Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.").
[64] *See* Proposed Rule, 87 Fed. Reg. at 79,184 ("These proposed revisions would clarify the procedures for considering RULOF by establishing a robust analytical framework that would require a state to provide a sufficient justification when applying a standard of performance that is less stringent than the EPA's presumptive level of stringency.").
[65] *See* Supplemental Oil and Gas New Source Performance Standard and EG Proposal for GHGs, 87 Fed. Reg. 74,702, 74,834 (Dec. 6, 2022).
[66] *See* Proposed Rule, 87 Fed. Reg. at 79,182.
[67] *See* 42 U.S.C. § 7411(d)(1).

(iv) The deadline for submitting state plan revisions in response to a revised EG also should provide sufficient time.

As discussed above, the primary reason that more time is required to prepare an original state plan is because of the time it takes to comply with various process-related requirements, including the proposed meaningful public engagement and RULOF procedures. Under Subpart Ba, any revisions to a state plan must be made using the same procedures and in compliance with the same requirements as are required for developing and submitting the original plan.[68] Thus, the same process-related challenges that states face in developing their original plans would be present for a plan revision in response to a revised EG. This means that the deadline for submitting state plan revisions should also provide sufficient time for these procedural steps.[69]

2. The deadline for federal plan development should run from the Agency's issuance of a finding of failure to submit or its disapproval of a state plan.

For state plans that are timely submitted and then disapproved by EPA, the Agency is proposing that its 12-month deadline to issue a federal plan would run from the date of the state plan disapproval.[70] The Class of '85 supports this but objects to EPA's proposal regarding the development of federal plans when a state does not timely submit a complete plan.

For states that do not timely submit a complete plan, EPA is proposing to tie its deadline for issuing a federal plan to the state plan submission deadline, rather than EPA's issuance of a finding of failure to submit.[71] In that scenario, EPA's 12-month clock to issue a federal plan would start the day after the state plan was due. EPA proposes to continue to issue findings of failure to submit because this finding "has value in notifying states and the public of the status of plans," but the finding would no longer function as the trigger for the federal plan deadline.[72] The Class of '85 opposes "starting the clock" on the day after a state has missed its deadline to submit a complete plan. Instead, EPA should continue to use its finding of failure to submit as the trigger for determining when the federal plan must be issued.

EPA does not have authority to decouple the federal plan deadline from the finding of failure to submit. Section 111(d)(2) provides that EPA "shall have the *same* authority" as the Agency has under Section 110(c) to issue a federal implementation plan ("FIP") "in cases where the State fails to submit a satisfactory plan."[73] EPA therefore is not authorized to deviate from the

[68] *See* 40 C.F.R. § 60.28a(a).
[69] *See* Redline § 60.28a(a).
[70] EPA also should consider giving itself more than 12 months for issuing a federal plan, particularly because the Agency is required to consider RULOF when issuing a federal plan. *See* 42 U.S.C. § 7411(d)(2). For the same reasons that the Class of '85 is concerned about the 15-month timeframe being insufficient for states to conduct their *optional* RULOF analyses, *see supra* Section II.B.1.iii, the Group also is concerned that 12 months is insufficient for EPA to conduct its *mandatory* RULOF analyses.
[71] *See* Proposed Rule, 87 Fed. Reg. at 79,189–90.
[72] *Id.* at 79,190.
[73] 42 U.S.C. § 7411(d)(2) (emphasis added).

Section 110(c) procedures for issuing a FIP, which are that the Agency must issue a FIP after EPA either makes a finding of failure to submit or disapproves a SIP.[74]

Even if EPA did have the authority to deviate from the Section 110 FIP trigger for Section 111(d) federal plans, there are compelling policy reasons that the Agency should not do so. Conforming the Section 111(d) federal plan trigger to that of Section 110 would provide helpful uniformity and clarify obligations for state air agencies that are accustomed to planning around the timing requirements for developing and submitting SIPs and for being subject to FIPs. Additionally, requiring EPA to first issue a finding of failure to submit before the clock starts on the federal plan deadline provides transparency to the public regarding the status of the plan.

3. EPA should clarify how states may satisfy the proposed "meaningful public engagement" requirement.

EPA is proposing to require "meaningful public engagement" as a prerequisite to the Agency's completeness determination for a state plan submission.[75] The proposed definition of "meaningful public engagement" requires "timely engagement with pertinent stakeholder representation in the plan development or plan revision process," including "early outreach, sharing information, and soliciting input on the state plan."[76] It emphasizes that engagement "must not be disproportionate in favor of certain stakeholders" and must include strategies to overcome barriers to participation, with recognition of any "diverse constituencies" present in the stakeholder community.[77]

The Agency's proposed definition is vague. EPA has not provided sufficient specificity about the minimum level of outreach and engagement that would be sufficient to meet its proposed requirements for state plan completeness. Without this clarity, states would face uncertainty about the approvability of their plans by EPA and, in turn, EPA's plan approvals would be vulnerable to legal challenges based on allegations of insufficient public engagement. This risks delaying the implementation of state plans and creating regulatory uncertainty for affected facilities. The Implementing Regulations are an appropriate place for outlining a presumptively approvable "safe harbor" approach to public engagement because—unlike EG details that are specific to each source category, such as what constitutes BSER and which compliance mechanisms are appropriate for that BSER—"meaningful public engagement" should be a universally understood and implementable concept for all EGs. EPA also should consider defining "pertinent stakeholders" in future EG rulemakings, as the identification of this group may differ depending on the pollutant and source category being addressed.

At the same time, EPA should avoid prescribing a one-size-fits-all approach to public engagement in the Implementing Regulations. The clarification requested by the Group should be

[74] *See id.* § 7410(c) ("(1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under subsection (k)(1)(A) of this section, or (B) disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.")
[75] *See* Proposed Rule, 87 Fed. Reg. at 79,190–92.
[76] Redline § 60.21a(k).
[77] *Id.*

developed in consideration of states' existing or developing requirements for public engagement in their own rulemaking processes, which are far from uniform across the country.

4. EPA should promulgate a more realistic deadline for making completeness determinations for Section 111(d) state plans.

EPA's proposal to make completeness determinations on state plans within 60 days of receipt by the Agency is unrealistic.[78] It is improbable that the Agency would be able to timely make determinations on state plan completeness within this short timeframe, which would result in the state plans being deemed complete by operation of law.[79] Given that EPA is proposing to disapprove state plans that lack sufficient "meaningful engagement," states whose plans were deemed complete by operation of law (in lieu of an affirmative determination by EPA after Agency review of required state plan elements) might not learn until late in the process that their public participation was inadequate. The impact of this would be particularly acute for states that must submit plans under EGs issued soon after the final Implementing Regulations take effect; the earliest state plans would have to be developed without the benefit of states being able to learn from prior EPA approvals and disapprovals of the public engagement elements of state plans.

5. EPA should promulgate a more realistic default trigger and timeframe for compliance with Section 111(d) state plans.

EPA is proposing to require states to include legally enforceable increments of progress in their plans whenever the compliance schedule for a designated facility or category of facilities extends more than 16 months after the state plan submittal deadline.[80] The Class of '85 generally supports the Agency's proposal to retain in the Implementing Regulations the option for a state plan to include a longer compliance schedule if necessary for individual sources or categories of sources to reasonably achieve compliance with the standard of performance.[81] However, the compliance schedule EPA is proposing is still insufficient.

Under the Proposed Rule, EPA would have up to 14 months from the deadline for a state plan submittal within which to take final action on the state plan—two months from the submittal deadline to make a completeness determination and 12 months after that for final action on the state plan.[82] If EPA timely approves the plan, there will only be two months left in the "default" 16-month compliance timeframe before increments of progress are triggered. Two months is an unreasonably short and unrealistic timeline for compliance with a standard of performance. The alternative is for an affected facility to spend that 14-month period working to implement their proposed compliance obligations under the submitted state plan only to risk EPA disapproving the plan late in the process, potentially subjecting the affected facility to material, non-recoverable expenditures. This approach risks wasting valuable time and resources on compliance with a standard that ultimately may not be approved. Further, some states' public service commissions

[78] *See* Proposed Rule, 87 Fed. Reg. at 79,184–85.
[79] *See id.* at 79,184 (proposing to mirror the Section 110(k)(1)(B) requirement that SIPs not timely deemed complete by EPA will be deemed complete by operation of law).
[80] *See id.* at 79,181–82.
[81] *See* Redline § 60.24a(d)(1).
[82] *See* Proposed Rule, 87 Fed. Reg. at 79,189.

will not allow electric generators to expend resources on compliance with a plan that is subject to material change or disapproval.

States and sources should not be expected to comply with a plan before knowing whether it will be approved by EPA. This would be unfair to both the affected facilities and the interested public, whose opportunity to comment on EPA's proposed approval of a state plan is essentially meaningless if the Agency expects sources to begin complying with a proposed state plan before EPA has considered or even received input from the public. In effect, pegging the compliance timeframe to a state's submittal deadline instead of to EPA's final approval of a plan presupposes that the Agency will approve every state plan, regardless of what might be raised during the notice-and-comment process. This is contrary to what is required by the Administrative Procedure Act, which provides that the public be given "an opportunity to participate" in the rulemaking process via the submission of comments and requires the agency to "consider[] the relevant matter presented" before issuing a final rule.[83]

The Class of '85 urges EPA to address this problem by linking the trigger for increments of progress to the date on which EPA takes final action to approve a state plan, instead of pegging the trigger to the state plan submittal deadline.

C. EPA Lacks Authority to Adopt the Proposed "State Plan Call" and "Error Correction" Mechanisms as Currently Drafted.

1. Section 111(d) does not authorize EPA to issue "SIP calls" for state plans.

EPA is proposing to add to the Implementing Regulations a mechanism analogous to a SIP call, which purports to allow the Agency to find that a previously approved state plan does not satisfy applicable requirements and call for a plan revision.[84] The Proposed Rule identifies two circumstances under which EPA finds that a state plan call "would be generally appropriate."[85] First, when legal or technical conditions arise after EPA's state plan approval that undermine the basis for approval, such as a court decision; and second, when a state "fails to adequately implement an approved state plan."[86] In other words, EPA proposes to allow for "calls" under Section 111(d) when a plan itself is inadequate, as well as when a plan is adequate but the implementation of the plan is inadequate. However, the Class of '85 believes the governing statute does not provide EPA with this "SIP-call-like" authority because (1) EPA lacks legal authority to issue plan "calls" under Section 111(d); (2) even if EPA had such authority, the Agency could issue plan "calls" under Section 111(d) *only* on the ground of inadequacy of the plan itself and not on the ground of inadequate implementation of the plan; and (3) regardless of EPA's legal authority to issue plan "calls" under Section 111(d), EPA should not do so because it would be bad policy.

[83] 5 U.S.C. § 553(c).
[84] *See* Proposed Rule, 87 Fed. Reg. at 79,194.
[85] *Id.*
[86] *Id.* at 79,195.

(i) EPA does not have authority under Section 111(d) to issue "SIP calls" because it would be contrary to congressional intent.

The Class of '85 disagrees with EPA's legal justification for its ability to issue Section 111(d) plan "calls." EPA bases its authority on Section 111(d)(2), which, according to the Agency, grants it "the 'same' authority to enforce state plan requirements as it does for SIPs under CAA sections 113 and 114, and to promulgate a Federal plan for a state that has failed to submit a satisfactory plan, as under CAA section 110(c)."[87] According to EPA, "read together, CAA section 111(d)(1) and (2) provide the set of essential procedural requirements for state and Federal plans that generally reflect the essential procedural requirements for SIPs and FIPs in section 110."[88]

Although EPA has authority under Section 110(c) to issue a FIP when a SIP is inadequate,[89] the authority to issue a "SIP call" requiring a state to revise its SIP if the Agency finds that the previously approved SIP is "substantially inadequate to . . . comply with any requirement of [the Act]" comes from Section 110(k)(5).[90] Section 111(d) incorporates by reference only EPA's authority to issue a FIP under Section 110(c); it *does not* incorporate by reference EPA's authority to issue a "SIP call" under Section 110(k)(5).[91] Accordingly, the language of Section 111(d) plainly fails to grant EPA "SIP-call-like" authority.

EPA's reasoning overlooks key differences in the authority Congress intended the Agency to have under Section 110 as compared to Section 111(d). Congress expressly granted EPA's current Section 110 "SIP call" authority in 1990, when it added Section 110(k)(5) to the Clean Air Act, along with other procedural enhancements to EPA's SIP authority.[92] However, Congress did not expressly grant such SIP-call authority to the Agency under Section 111(d)—not in 1990, and not since. Had Congress intended to extend this authority to Section 111, it would have (or should have) expressly done so.[93] In short, EPA is attempting to arrogate to itself authority that Congress never intended to grant.[94]

The federal government's role in implementing Clean Air Act programs like Section 111(d) is to assist states and function as a backstop, with authority to review state actions, consistent with the framework carefully established by Congress.[95] In proposing to grant itself the authority to issue "calls" for revisions to state plans when Congress has not made it clear that it intends for the Agency to have such authority under Section 111(d), EPA risks seizing authority

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[87] *Id.* at 79,193.
[88] *Id.*
[89] *See id.*
[90] 42 U.S.C. § 7410(k)(5).
[91] *See id.* § 7411(d)(2)(A).
[92] *See* Proposed Rule, 87 Fed. Reg. at 79,193.
[93] *See Whitman v. American Trucking Ass'ns*, 531 U.S. 457, 468 (2001) ("Congress . . . does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes.").
[94] *See North Carolina v. EPA*, 531 F.3d 896, 922 (D.C. Cir. 2008) (EPA has "'only those authorities conferred upon it by Congress'").
[95] *See* 42 U.S.C. § 7401(a)(4) ("Federal financial assistance and leadership is essential for the development of cooperative Federal, State, regional, and local programs to prevent and control air pollution").

that Congress intended to grant to the states. EPA should abandon this element of the Proposed Rule.

(ii) Even if EPA had legal authority under Section 111(d) to issue "SIP calls," the Agency could do so only on grounds that a state plan itself is inadequate.

The legal basis for EPA's authority to issue "calls" of Section 111(d) plans on grounds of inadequate implementation is even more tenuous than a "call" for a revision of a plan that the Agency deems inadequate on the plan's own terms. Even if EPA did have "SIP-call-like" authority under Section 111(d) generally, the Agency would overstep the bounds of this authority by "calling" for a state to revise a plan that is otherwise adequate but for the state's failure to implement the plan. The Class of '85 strongly objects to this proposed mechanism.

EPA proposes that the text of Section 110(k)(5) grants it the authority to call for revisions on the basis of inadequate implementation.[96] However, the Agency cites no authority for this reading of Section 110(k)(5) and offers no indication that it has *ever* interpreted Section 110(k)(5) to permit this type of "SIP call" in the context of Section 110.[97] Rather, EPA has issued (1) "SIP calls" under Section 110(k)(5) when a plan *itself* is inadequate,[98] and (2) sanctions for a state's *failure to implement* a plan under other provisions of the Clean Air Act (*i.e.*, not Section 110(k)(5)).[99] The Agency does not explain why the authority to issue "calls" based on a state's failure to adequately implement its plan would exist in the context of Section 111(d) but not in the context of Section 110. If EPA cannot issue "SIP calls" based on inadequate implementation under Section 110, it should not be able to do so for Section 111(d) state plans.

EPA already has a device under the Clean Air Act to correct a state's failure to adequately implement a Section 111(d) plan: Section 113, which covers federal enforcement of SIP requirements. Indeed, Section 111(d)(2) cross-references Section 113 (in addition to Section 110). Specifically, Section 111(d)(2) provides that EPA has the authority under Section 113 "to enforce the provisions of [a state plan] in cases where the State fails to enforce them as [EPA] would have under [Sections 113 and 114] with respect to an implementation plan."[100] Section 113, in turn, allows EPA to notify a state whenever the Agency finds that violations of a plan "are

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[96] *See* Proposed Rule, 87 Fed. Reg. at 79,194.

[97] *See id.*

[98] *See, e.g.*, Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 57,356, 57,367 (Oct. 27, 1998) ("NOx SIP Call") (determining SIPs to be "substantially inadequate . . . because the relevant SIPs do not contain adequate provisions prohibiting their sources from emitting amounts of NOx emissions that contribute significantly to nonattainment in downwind areas"); *see also* State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls To Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction, 80 Fed. Reg. 33,840, 33,845 (June 12, 2015) (determining certain SIP provisions, including automatic and discretionary exemptions from applicable emission limitations during startup, shutdown, and malfunction ("SSM") events, to be "'substantially inadequate' to meet CAA requirements").

[99] *See* 42 U.S.C. §§ 7410(m), 7509(a)(4),(b) (setting forth sanctions, including withholding of federal highway funds, for states where "any requirement of an approved [Section 110] plan . . . is not being implemented"); *see also* Compliance with the Statutory Provisions of Part D of the Clean Air Act, 48 Fed. Reg. 50,686, 50,687 (Nov. 2, 1983) (noting that EPA imposes construction bans and funding restrictions under various provisions of the Act in areas where state or local agencies have failed to carry out a SIP).

[100] *See* 42 U.S.C. § 7413.

so widespread that such violations appear to result from a failure of the State . . . to enforce the plan . . . effectively."[101] If the state fails to remedy this issue, EPA may "assume[] enforcement" of any requirement or prohibition of the state plan, including issuing administrative orders, administrative penalties, or bringing civil actions.[102] Thus, Section 113 procedures and remedies—not state plan "calls"—are the appropriate approach for EPA to pursue if states are not meeting their obligations to achieve the emission reductions outlined in an approved Section 111(d) plan. EPA would not only be acting *ultra vires* if it finalizes the proposed "SIP-call-like" authority under Section 111(d), but it also would be seeking to solve a problem that already has a congressionally provided solution.

(iii) Regardless of EPA's legal authority to issue "SIP calls" under Section 111(d), the Agency should not do so because it would be bad policy.

Although the Class of '85 believes that EPA clearly lacks legal authority to issue state plan "calls" under Section 111(d), the Group further urges the Agency not to pursue this option on policy grounds. Even if EPA has legal authority to revise the Section 111(d) regulations to allow for such "calls," the Agency would have the discretion *not* to do so—and should exercise this discretion because a state plan "call" would undermine the goals of regulatory certainty and cooperative federalism.

The prospect of a federal government "call" of a Section 111(d) plan would undermine regulatory certainty and predictability for states and designated facilities. If EPA could order a revision of (and possibly revoke and replace) a state plan that has been approved and is being implemented, states and designated facilities could never be confident that the state plan under which they are operating will remain in place. A Section 111 state plan imposes unit-specific requirements, so an affected facility could expend resources to come into compliance with a standard of performance, only for EPA to call for revisions to those standards that undercut those investments and associated planning decisions. For EGUs subject to a state plan "call," this uncertainty could affect project planning (which generally involves long time horizons for the electric generating industry, and, thus, requires long-term certainty) and increase compliance costs. It also may disincentivize affected EGUs from working with states to develop plans that are calibrated to local circumstances, since these extra efforts could be undermined at any moment by a state plan "call." Likewise, states also may be less willing to devote resources to developing, implementing, and enforcing a plan that EPA could later revoke. This would undermine EPA's intent to "streamline the state plan review and approval process . . . and generally enhance the administration of the [Section 111(d)] program."[103]

The risks of regulatory uncertainty are even greater for Section 111(d) plan "calls" that would be issued on the basis of inadequate implementation. There is no pre-existing guidance under Section 110 as to what would trigger a "call" on these grounds. At a minimum, EPA should clarify in the final rule the specific circumstances that would qualify as a state "fail[ing] to adequately implement" a plan such that the requirements of the plan are rendered "substantially inadequate."[104] The preamble to the Proposed Rule provides no guidance regarding what a state

[101] *Id.* § 7411(d)(2)(B).
[102] *Id.* § 7413(a)(2).
[103] Proposed Rule, 87 Fed. Reg. at 79,193.
[104] *See id.* at 79,195.

would need to do (or not do) to trigger such a "call" of its plan.[105] The Class of '85 requests that EPA provide further guidance on this issue if the Agency proceeds with amending the Implementing Regulations to provide itself with authority for both types of "SIP-call-like" mechanisms under Section 111(d).

2. The Class of '85 urges EPA to provide clearer limits on the proposed "error correction" provision for state plans.

EPA is proposing to add an "error correction" provision that would purportedly authorize the Agency to revise a prior action under Section 111(d) without requiring further submissions from the state when EPA determines that its own action on a state plan was in error. Revisions would take place "in the same manner as used for the original action (*e.g.*, through rulemaking)."[106] EPA should more clearly define the circumstances where its use of the error correction provision would be appropriate in the Section 111(d) context, rather than simply stating that "[t]he circumstances that may give rise to an error that the EPA may correct with this mechanism depend on the specific facts and plan at issue, and the use of the mechanism is more appropriately justified on a case-by-case basis."[107]

As currently drafted, the proposed regulatory text does not place *any* limitations on EPA's ability to use the error correction provision.[108] EPA should clarify that it is not appropriate to use the error correction mechanism to reverse an approval determination for a state plan and also should impose meaningful limits on its ability to use this mechanism to effectuate significant changes to a prior action or implement new policy perspectives. Such a broad use of this mechanism would create significant regulatory uncertainty, as states would be forever subject to the risk that EPA may decide to reverse its approval of a state plan, even after the plan has been implemented.

The Proposed Rule states that, "[w]hile the EPA maintains that this proposed error mechanism would be available for acting on state plans when appropriate, the EPA expects that it will work with states, as it has done previously in the SIP context, to correct any deficiencies in their plans."[109] The Class of '85 recommends that the Agency codify this directive, *i.e.*, that the Agency will attempt to work with states to correct deficiencies in their plans before pursuing the unilateral error correction option. In addition, EPA should clarify that, while states would not be *required* to make any further submissions, states would be *allowed* to submit additional information when EPA is considering proposing an error correction.

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[105] *See id.*
[106] *Id.* at 79,195–96.
[107] *Id.* at 79,195.
[108] The proposed regulatory text for the error correction provision, in its entirety, reads as follows: "Error corrections. Whenever the Administrator determines that the Administrator's action approving, disapproving, or promulgating any plan or plan revision (or portion thereof) was in error, the Administrator may in the same manner as the approval, disapproval, or promulgation revise such action as appropriate without requiring any further submission from the State. Such determination and the basis thereof shall be provided to the State and public." *See* Redline § 60.27a(j).
[109] Proposed Rule, 87 Fed. Reg. at 79,196.

D. Several of EPA's Proposed Updates to the RULOF Provisions are Unreasonable and Should be Modified.

In the preamble to the Proposed Rule, EPA recognizes its statutory obligation to allow states to consider remaining useful life and other factors when applying standards of performance to particular sources.[110] The Agency further concedes that "consideration of remaining useful life in particular can be an important consideration, as the cost of control for a specific designated facility that is expected to cease operations in the near term could significantly vary from the average cost calculations performed as part of the BSER determination for the source category as a whole."[111] Nonetheless, EPA is proposing to (1) limit states' ability to rely on a retirement date to justify a less stringent standard of performance, (2) narrow the applicability of the RULOF mechanism, and (3) impose new requirements when applying a less stringent standard of performance based on RULOF.[112] EPA should not finalize these elements of the Proposed Rule because Section 111(d) does not authorize EPA to restrict the states' authority to incorporate remaining useful life and other factors into standards of performance.

1. EPA should not limit state authority to consider a facility's retirement date to justify a less stringent standard of performance.

EPA is proposing to limit states' and its own ability to rely on a facility's retirement date to justify a less stringent standard of performance.[113] Specifically, the Agency proposes to identify in an EG "an outermost remaining useful life date that would provide the latest retirement date that states can rely on for a designated facility" or a specific methodology and list of considerations to be applied by states in determining whether a retiring source qualifies for a less stringent standard.[114] The Class of '85 strongly opposes this proposed bright-line rule.

EPA's proposed one-size-fits-all approach would be inconsistent with the purpose of the RULOF provision, which is to address individualized facility characteristics that affect the appropriateness of a standard of performance for a particular source. If the retirement date used as an input in the RULOF analysis is prescriptively limited by EPA, then it may inappropriately eliminate states' ability to consider the remaining useful life of a particular facility that has a retirement date beyond the cutoff date. This is inconsistent with the states' authority to consider RULOF. Further, as the Agency itself recognizes, "EPA cannot necessarily anticipate the appropriate and potentially unique implementation needs for every future EG."[115] Facility retirements are exactly the kind of unique implementation considerations that states may take into account when determining the appropriateness of a less stringent standard, making EPA's proposed approach incongruous. In the case of EGUs, facility retirements are not always entirely within the discretion of the unit's owner. For example, an EGU owner in the Midcontinent Independent System Operator ("MISO") region who wants to suspend or retire a unit must submit a request to

[110] *See id.*
[111] *Id.*
[112] *See id.* at 79,198.
[113] RULOF is not limited to state plans; EPA is required to take RULOF into account when promulgating federal plans. *See* 42 U.S.C. § 7411(d)(2).
[114] Proposed Rule, 87 Fed. Reg. at 79,201.
[115] *Id.* at 79,198.

MISO, which will evaluate the effect of the EGU retirement on system reliability and can even require the EGU to remain operational beyond the requested suspension or retirement date.[116]

The Agency's concern that a state may impose a less stringent standard that is not reasonably warranted is unfounded.[117] EPA retains the authority to approve or disapprove of a less-stringent standard of performance based on RULOF,[118] so there is no need for a prospective limitation on states' ability to consider a source's retirement date.

2. EPA should clarify the proposed requirements that would apply to retiring facilities.

For facilities that are near retirement, EPA is proposing to require that states impose "a reasonably achievable source-specific BSER" that applies until the retirement date.[119] This proposed requirement is vague and ambiguous. EPA does not define what constitutes a "reasonably achievable" standard or how it is to be determined.[120] Additional clarification is needed from EPA so that states and affected facilities understand what analysis should be performed to determine and justify such a standard.

EPA's proposed treatment of "imminently retiring sources" suffers from the same problem. For these sources, EPA proposes that the state apply "a standard no less stringent than one that reflects the designated facility's business as usual."[121] While the Class of '85 appreciates EPA's acknowledgement that these sources should not be required to invest in new emissions controls, "business as usual" is vague and requires clarification. For example, an imminently retiring EGU can be subject to maintenance schedules and operational constraints or demands that cause its emission performance to deviate from recent past performance up until the actual date of retirement. If an imminently retiring EGU is called into service unexpectedly based on unpredictable surges in electricity demand—such as during a severe weather event or to replace generation from a unit that must go offline for an unplanned repair—the EGU will be operating more than its "business as usual" and therefore could become noncompliant with its standard of performance.

3. Section 111(d) confers clear authority to states to apply a less stringent standard of performance after considering RULOF.

EPA is proposing to limit states' ability to consider RULOF when determining whether a less-stringent standard of performance is appropriate for a facility. States would be required to demonstrate that a particular facility cannot reasonably achieve the degree of emission limitation

[116] *See* MISO, Generator Interconnection and Retirement FAQs, https://www.misoenergy.org/planning/generator-interconnection/ (last visited Feb. 21, 2023).
[117] *See* Proposed Rule, 87 Fed. Reg. at 79,201 (arguing that if EPA "did not identify an outermost retirement date or specified methodology and conditions, then a state plan could attempt to account for the remaining useful life for a designated facility whose retirement date does not reasonably warrant a less stringent standard, undermining the control objectives of the EG and CAA section 111(d) itself.").
[118] *See* 42 U.S.C. § 7410(k)(3) (stating that the Administrator shall approve a state submittal if it meets all of the applicable requirements of the Clean Air Act).
[119] Proposed Rule, 87 Fed. Reg. at 79,202.
[120] *See* Redline § 60.24a(f)–(g).
[121] Proposed Rule, 87 Fed. Reg. at 79,202.

achievable through the application of BSER, based on "(1) an unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility or technical infeasibility of installing necessary control equipment; or (3) other circumstances specific to the facility (or class of facilities) that are fundamentally different from the information considered in the determination of the BSER in the emission guidelines."[122] Although EPA intends for these to be "[c]larifying parameters,"[123] the result would be a new set of restrictions on states' statutorily authorized RULOF analysis.

These proposed limitations on the RULOF analysis are contrary to the plain language of the Clean Air Act, which makes clear that EPA must allow states to consider RULOF. Section 111 expressly establishes that states have the authority to (1) determine the standard of performance applicable to specific existing sources;[124] and (2) consider "among other factors, the remaining useful life of the existing source to which such standard applies," in setting source-specific standards of performance.[125] While EPA retains the authority to approve or disapprove state plans, EPA has no discretion to deviate from the clear statutory text by restricting the states' ability to consider remaining useful life and other factors in setting and, where appropriate, modifying standards of performance.

Beyond the Clean Air Act's plain directive that states be allowed to account for RULOF, there are compelling policy reasons for EPA to refrain from limiting states' authority in this area. Retaining flexible requirements allows states to better account for the unique characteristics of individual sources and regional needs. For example, in the power sector, it is important for operators and states to retain flexibility to consider various factors that affect reliability, such as which power plants dispatch on a given system or operate at any given time based on the cost of service, voltage support, electricity demand, and availability of renewable resources. States, not EPA, are in a better position to incorporate these considerations into appropriate standards of performance for EGUs.

4. EPA should not interpret "other factors" in the RULOF provisions as allowing states to impose more stringent standards of performance on particular sources.

EPA is proposing to revise its interpretation of the statutory RULOF provision as authorizing states to consider other factors to apply a *more stringent* standard of performance to a particular source.[126] According to EPA, such an interpretation is consistent with Section 116's anti-preemption provisions because that section "generally authorizes states to include more stringent standards of performance or requirements regarding control or abatement of air pollution in their plans."[127] The Class of '85 disagrees with this interpretation because it is inconsistent with the legislative history of the RULOF mechanism.

As EPA recognizes in the Proposed Rule, the conference report for the 1977 Clean Air Act Amendments said the following about the then-new statutory RULOF provision: "The section also makes clear that standards adopted for existing sources under section 111(d) of the Act are to be

[122] *Id.* at 79,199.
[123] *Id.* at 79,197.
[124] *See* 42 U.S.C. § 7411(d)(1)(A).
[125] *See id.* § 7411(d)(1)(B).
[126] *See* Proposed Rule, 87 Fed. Reg. at 79,204.
[127] *Id.*

based on available means of emission control (not necessarily technological) and must, *unless the State decides to be more stringent*, take into account the remaining useful life of the existing sources."[128] Congress would not have needed to caveat this statement with "unless the State decides to be more stringent" if it intended for RULOF to also be considered when a state wishes to apply a standard of performance that is more stringent than required under a particular EG. EPA is proposing to reverse its prior position on this legislative history because the conference report addresses "remaining useful life" but is silent as to the "other factors."[129] However, this proposed interpretation ignores the scope of Congress's statement in the conference report. The conference report language quoted above refers to the entirety of Section 111, as is apparent from the formatting of this section of the report. This would include the "other factors" in addition to "remaining useful life." In other words, Congress's explanatory language in the conference report was not limited solely to "remaining useful life."

E. Additional Recommendations.

The Class of '85 offers the following additional recommendations for EPA:

- **EPA should clarify the applicable compliance deadline for a state plan that is conditionally approved by the Agency.** As currently drafted, the Proposed Rule does not specify the "trigger" date for compliance deadlines when EPA conditionally approves a state plan. The Class of '85 believes that, in this scenario, compliance deadlines should begin to run when the state satisfies the condition(s) established by EPA. Regardless of what "trigger" EPA uses, the Agency should clarify the regulatory text so that states and affected facilities have clarity around when their compliance obligations must be met.

- **EPA should publish proposed regulatory text in the *Federal Register* in future rulemakings.** EPA did not include the proposed regulatory text in its *Federal Register* notice of the Proposed Rule. Rather, the Agency referred the public to a "redline strikeout" memorandum in the rulemaking docket. It was unnecessarily confusing and difficult to find this memorandum in the docket, especially because the docket contained numerous regulatory-text memos and the final version was not clearly identified as such. Additionally, this memorandum was not posted to EPA's website until nearly one month after the Proposed Rule was published. This approach could result in the public being denied sufficient notice and opportunity to comment on future proposed rules as required by the Clean Air Act and the Administrative Procedure Act.[130] Specifically, the practice of posting the regulatory text in a separate document creates the unnecessary risk of discrepancies between the proposed regulatory text contained in the docket and the description of the proposed text in the *Federal Register* notice. Such discrepancies would prevent stakeholders from receiving notice of EPA's proposed action and impair their ability to provide informed comments on the proposal. The Class of '85 requests that EPA return to its longstanding practice of including proposed regulatory text in the *Federal Register* notice for a proposed rule. This will provide clarity around the proposed

[128] H.R. Conf. Rep. No. 94-1742, (Sep. 30, 1976), 1977 CAA Legis. Hist. at 88 (emphasis added).
[129] *See* Proposed Rule, 87 Fed. Reg. at 79,205.
[130] *See* 42 U.S.C. § 7607(d); 5 U.S.C. § 553.

regulatory action and ensure that the public has adequate notice and an opportunity to comment on the proposed regulatory language.

III. CONCLUSION

The Class of ’85 appreciates the opportunity to submit comments on the Proposed Rule. The Group urges EPA to make the recommended changes and take the additional actions requested in these comments, which will ensure that the Implementing Regulations are consistent with the Agency’s Clean Air Act authority, and that they establish realistic requirements for states, designated facilities, and EPA alike.

Dated: February 27, 2023

Respectfully submitted,

The Class of ’85 Regulatory Response Group
contact@class-of-85.com

Attachment A

AES Corporation
Alliant Energy Corporation
Ameren
Arizona Public Service
Arizona Electric Power Cooperative, Inc.
Arkansas Electric Cooperative Corporation
Basin Electric Power Cooperative
City of Tallahassee
Cleco Corporation
Cogentrix Energy Power Management, LLC
Dairyland Power Cooperative
Dayton Power & Light Company
Dominion Energy
Duke Energy
Entergy Services, LLC
Evergy, Inc.
Florida Municipal Electric Association
Gainesville Regional Utilities
Great River Energy
Hawaiian Electric Company, Inc.
Indianapolis Power & Light Company
JEA
Lakeland Electric
Louisville Gas & Electric/Kentucky Utilities
Luminant Generation Company LLC
Minnesota Power
National Grid
NRG Energy
OGE Energy Corp.
Orlando Utilities Commission
Portland General Electric
PowerSouth Energy Cooperative
Public Service Company of New Mexico
Rainbow Energy Center, LLC
Salt River Project
Southern Company
Talen Energy
Tampa Electric Company
Tucson Electric Power Company
Western Farmers Electric Cooperative
Xcel Energy Inc.