COMMENTS OF THE POWER GENERATORS AIR COALITION ON THE U.S. ENVIRONMENTAL PROTECTION AGENCY'S 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; PROPOSED RULE

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

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

August 8, 2023

Table of Contents

Page

I. Background 2

II. Executive Summary 4

III. The Proposed Rules Threaten Both the Reliability and Affordability of Electricity, and EPA Needs to Carefully Analyze this Issue More Broadly to Avoid Instability in the Electric Grid 9

IV. The Proposed Rules Violate the Requirements of Section 111 of the CAA 18

A. Legal Standard for Performance Standards under Section 111 18

1. "Adequately Demonstrated" 20

2. "Achievable" 22

3. Consideration of Statutory Factors for "Best" Adequately Demonstrated System 23

B. CCS Does Not Meet the Requirements of Section 111 25

1. CCS Is Not Adequately Demonstrated at Fossil Fuel-Fired EGUs 26

a. Combustion Turbines 26

b. Steam Generating Units 30

2. EPA's Proposed NSPS for New and Modified Fossil-Fuel Fired EGUs and Presumptively Approvable Emission Limitations for Existing Fossil Fuel-Fired EGUs that Are Based on CCS Technology Are Not Achievable. 34

3. CCS Has Many Obstacles that Prevent it From Being Considered as a "Best" System to Reduce GHG Emissions from Fossil Fuel-Fired EGUs 38

a. Geographic and Site Limitations 38

b. Water Constraints 42

c. Parasitic Load 44

d. Cost 46

C. Hydrogen Co-Firing at Natural Gas-Fired Combustion Turbines Does Not Meet the Requirements of Section 111 of the CAA and Impermissibly "Redefines" the Source. 48

1. The Ability of Combustion Turbines to Combust Hydrogen at the Levels Contemplated by EPA and Over an Extended Period of Time Is Not Adequately Demonstrated. 49

2. The Supply of Low-GHG Hydrogen Needed to Implement the Proposed Rules Does Not Exist 52

3. Even if There Were an Ample Supply of Low-GHG Hydrogen to Implement the Proposed Rules, The Infrastructure Needed to Transport and Store the Hydrogen Does Not Exist. 54

4. EPA's Proposed BSER for Hydrogen Co-Firing Impermissibly Redefines the Source 57

D. Co-Firing with Natural Gas at Coal-Fired EGUs Does Not Meet the Requirements of Section 111 and Impermissibly Redefines the Source. 58

E. EPA's Assumption that Technologies and Their Required Infrastructure Will Be Adequately Demonstrated and Achievable Several Years—and in Some Cases More Than a Decade—in the Future Is Not Reasonable and Violates the CAA 61

V. EPA's Timeline for Compliance with the Proposed Rules is Unrealistic. 63

VI. The Proposed Rules Violate the Major Questions Doctrine, which the Supreme Court Warned EPA About in *West Virginia v. EPA*. 66

VII. The Applicability Dates for the Proposed Rules are Incorrect as a Matter of Law. 73

VIII. The Proposed Rules Impermissibly Restrict States' RULOF Determinations. 75

IX. EPA Should Assist the States by Providing a Model Trading Rule Based on Mass-Based Presumptively Approvable Emission Limits that States Can Adopt. 78

A. EPA Should Issue a Model Trading Rule for Existing Sources that States May Opt Into and that Would Be a Fully Approvable and Automatic State Plan. 79

B. EPA Should Not Unduly Restrict Emissions Trading. 82

C. EPA Should Provide States with Alternative Mass-Based Presumptively Approvable Emission Limits. 85

X. EPA's Environmental Justice Analysis Should Examine the Effects on Environmental Justice Communities of Decreased Electric Reliability and Lack of Access to Affordable Electricity. 87

A. Electricity Prices and Energy Security 88

B. Reliability 91

C. Cap-and-Trade Evaluations 93

D. Safety 96

XI. EPA's IPM Analysis on Which the Proposed Rules Rely Is Deeply Flawed. 97

A. EPA's Base Case Is an Outlier, Inconsistent with Every Other Available Model, Including That Published by the EIA 98

B. IPM's Updated Baseline Does Not Consider Key Challenges Facing the Power Sector's Transition from Dispatchable Fossil Generation to Renewables 99

C. EPA's 2030 "Base Case" Unrealistically Includes Significant Deployment of CCS at Coal-Fired EGUs, Inexplicably Retires Units that are Not Slated for Retirement by 2030, and Contains Other Errors 101

XII. EPA Failed to Provide Sufficient Time for Public Comment on the Proposed Rules, in Violation of the CAA and the Administrative Procedure Act. 102

XIII. Additional Items Needing Clarification or Changes 107

COMMENTS OF THE POWER GENERATORS AIR COALITION ON THE U.S. ENVIRONMENTAL PROTECTION AGENCY'S 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; PROPOSED RULE

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

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

The Power Generators Air Coalition ("PGen") respectfully submits these comments to the U.S. Environmental Protection Agency ("EPA" or "the Agency") in response to EPA's proposed rules entitled "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 ("Proposed Rules"), which were published in the Federal Register on May 23, 2023.[1] The Proposed Rules consist of five separate rules: (1) revised new source performance standards ("NSPS") for greenhouse gas ("GHG") emissions from new fossil fuel-fired stationary combustion turbine electric generating units ("EGUs"); (2) revised NSPS for GHG emissions from modified fossil fuel-fired steam generating EGUs; (3) emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs; (4) emission guidelines for GHG emissions from existing stationary combustion turbine EGUs; and (5) repeal of the Affordable Clean Energy Rule.[2]

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

[2] *Id.*

I. Background

PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies—public power, rural electric cooperatives, and investor-owned utilities—with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. PGen is a collaborative effort of electric generators to share information and expertise in the interest of effectively managing air emissions to meet and exceed environmental laws and regulations and in the interest of informing sound regulation and public policy.[3] PGen's members include leaders in the fundamental transition to cleaner energy that is currently occurring in the industry. PGen as an organization does not participate in legislative lobbying or litigation. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation.

PGen members own and operate fossil fuel-fired EGUs that are the subject of the Proposed Rules, as well as renewable resources, like wind and solar, and carbon-free nuclear power plants. As such, PGen is uniquely qualified to provide comments to EPA because its members have owned and operated fossil fuel-fired EGUs for decades and are subject to various provisions of the Clean Air Act ("CAA" or "the Act"), including section 111, the provision governing the Proposed Rules.

At the outset, PGen wants to make clear that it understands the importance of reducing GHG emissions to address climate change. The electricity generating sector has made significant GHG reductions, and is the industry with by far the greatest amount of reductions from 2005 to

[3] Additional information about PGen and its members can be found at https://pgen.org/.

2021.[4] During that period, the electric power sector's GHG emissions have fallen nearly 36 percent,[5] and the sector is no longer the biggest contributor to U.S. GHG emissions.[6] The vast majority of PGen members have established goals to reduce their GHG emissions, and several PGen members have set net-zero goals.

While PGen members take seriously the need to reduce GHG emissions, they take equally seriously their obligation to provide reliable electricity at an affordable price. PGen members are concerned that the Proposed Rules will interfere with this critical obligation, which could undermine public support for electric sector efforts to reduce emissions through low- and zero-carbon sources like wind, solar, and nuclear.

PGen has been actively engaged with EPA on this important issue. When EPA was seeking information during the pre-proposal stage, PGen met with EPA in Research Triangle Park on November 17, 2022, and then followed up with written comments to EPA's pre-proposal non-rulemaking docket on December 22, 2022.[7] PGen appreciates that the Agency appears to have adopted some of PGen's recommendations in the Proposed Rules. For example, PGen supports EPA's decision to allow states to adopt flexible compliance mechanisms such as emission averaging and trading—but reiterates its request for EPA to develop a model trading rule that states could easily adopt as an approvable state plan and that could serve as a federal plan where necessary. PGen

---

[4] Center for Climate and Energy Solutions, U.S. Emissions, https://www.c2es.org/content/u-s-emissions/ (citing EPA and EIA data for 2022).

[5] *Id.* By comparison, the transportation sector's GHG emissions fell by only a little less than 9 percent and the industrial sector reduced its emissions by a little more than 4 percent over the same period of time.

[6] *Id.* (graphic showing Energy-Related Carbon Dioxide Emissions by Sector).

[7] Comments of the Power Generators Air Coalition to EPA's Pre-Proposal Non-Rulemaking Docket on Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units, Docket ID No. EPA-HQ-OAR-2022-0723-0031 (Dec. 22, 2022) ("PGen Pre-Proposal Comments"). The PGen Pre-Proposal Comments are attached hereto as Attachment A and incorporated by reference.

also appreciates that EPA allows EGUs with near-term retirement dates to be subcategorized differently so as not to have to comply with as stringent requirements as those EGUs that will be operating longer, although PGen believes that those subcategorization dates need to be adjusted further out in time to ensure electric reliability concerns are addressed. PGen also appreciates EPA's acknowledgment in the Proposed Rules that gas-fired peaking units (both new and existing) are needed to ensure grid stability during the transition to low carbon energy.

PGen's detailed comments on the Proposed Rules follow. PGen remains available to continue to work with EPA in any way that the Agency may find helpful as it considers the Proposed Rules.

II. Executive Summary

PGen provides this Executive Summary for the convenience of the reader. It does not summarize every point made within these comments and should not be a substitute for reading the comments in their entirety.

EPA's Proposed Rules regarding regulation of GHG emissions from EGUs impermissibly relies on technologies that do not meet the legal threshold set out by Congress in section 111 of the CAA and threatens to impose unrealistic timelines. Importantly, the Proposed Rules will have a negative impact on electric reliability and affordability. PGen's comments on the Proposed Rules are summarized below.

The Proposed Rules threaten both the reliability and affordability of electricity, and EPA needs to carefully analyze this issue more broadly to avoid instability in the electric grid (Section III).

- The electric generating industry is in a period of transition toward increased use of renewable energy and decreasing use of fossil fuel-fired generation, with the retirement of fossil fuel-fired EGUs, particularly coal-fired EGUs, occurring at a rapid pace. These retirements have strained the grid and threatened electric reliability, as expressed by the North American Electric Reliability Corporation ("NERC").

- The Proposed Rules are not the only EPA regulations that will affect EGUs—and thus reliability. EPA needs to take those other rules into account and should consider harmonizing the compliance and retirement dates to make them consistent across all of the rules. EPA also needs to consider how other regulatory initiatives outside of environmental regulations—such as regulations increasing the use of electric vehicles—will affect electric reliability.
- The Proposed Rules will compound the issue of the retirement of fossil fuel-fired EGUs, and will lead to capacity factor restrictions on many units that do not retire. This will lead to further negative effects on electric reliability. EPA needs to consult with the Department of Energy ("DOE"), the Federal Energy Regulatory Commission ("FERC"), regional reliability authorities, and the states to ensure reliability is adequately addressed.
- EPA should consider providing a safety valve exemption for EGUs that adopt capacity factor restrictions that would allow those units to operate beyond those restrictions as needed for reliability during periods of extreme load.

The Proposed Rules violate the requirements of section 111 of the CAA (Section IV).

- While carbon capture and storage ("CCS"[8]) is a promising technology that is making advancements through a variety of pilot projects throughout the United States, it has not yet reached the legal threshold of being an adequately demonstrated technology. EPA's proposed determination that CCS is adequately demonstrated for new and existing combustion turbines is not grounded in any actual experience with this technology at these types of EGUs.
- Similarly, EPA's proposed determination that CCS is adequately demonstrated for modified and existing coal-fired steam generating units violates section 111 because there is no evidence that CCS technology can capture 90 percent of the carbon dioxide ("CO_2") emissions from a facility that is not a slipstream facility and do so on a consistent basis, and because there is no evidence that CCS technology can work on large, commercial scale EGUs.
- The proposed NSPS for new and modified fossil fuel-fired EGUs and the presumptively approvable emission limitations for existing fossil fuel-fired EGUs that are based on CCS are not achievable across the country and thus violate section 111. Many areas of the country do not have ready access to geologic storage and the construction of a CO_2 pipeline is expensive, time-consuming, and subject to organized public opposition.
- CCS has several issues that prevent it from being a "best" system of emission reduction, including geologic storage issues. CCS also requires significant water for process operations, which further limits its geographic availability. There is also a significant parasitic load associated

[8] CCS is also sometimes referred to as carbon capture, utilization, and storage ("CCUS"). The "utilization" piece of CCUS stands for the concept that the captured carbon could be re-used in industrial processes such as enhanced oil recovery ("EOR") or by converting it into a product like concrete.

with the operation of CCS equipment that EPA has not fully examined. CCS continues to be expensive, even with the possibility of funds under the Inflation Reduction Act ("IRA").

- Hydrogen co-firing at natural gas-fired combustion turbines is another promising technology that does not yet meet the CAA's requirements for adequate demonstration. There is no evidence of the ability of combustion turbines to combust hydrogen at the levels contemplated by the Proposed Rules over an extended period of time, as confirmed by one of the largest construction and engineering companies involved in the development of hydrogen projects.
- EPA has also failed to adequately address the significant increases in nitrogen oxide ("NOx") emissions that result from hydrogen combustion.
- There is not a current supply of low-GHG hydrogen that can come even close to being able to provide the amount of hydrogen necessary under the Proposed Rules, and EPA's speculation that it will be available in the timelines set out in the rules is impermissible "crystal ball inquiry."
- Even if there were an ample supply of low-GHG hydrogen (which there is not), the infrastructure for transporting and storing the hydrogen is completely lacking, and there is no guarantee it will be available by 2032 and 2038 to fulfill the requirements of the Proposed Rules.
- The Proposed Rules' requirements that natural gas-fired EGUs combust significant amounts of hydrogen impermissibly redefines the source. The same is true for the Proposed Rules' requirements that natural gas be co-fired at coal-fired EGUs. Moreover, the vast majority of coal-fired EGUs do not have access to any amount of natural gas.
- EPA's assumption that technologies and their required infrastructure will be adequately demonstrated and achievable several years—and in some cases more than a decade—in the future is not reasonable and violates the CAA.

EPA's timeline for compliance with the Proposed Rules is unrealistic (Section V).

- The timelines set out in the Proposed Rules are unrealistic and unachievable. For example, existing coal-fired steam generating units that are characterized as long-term are subject to presumptively approvable emission limits based on CCS with 90 percent capture by 2030. Unless an owner or operator has already begun the process of pursuing CCS for the unit, it is already too late. There are too many permitting and other hurdles to overcome within the allotted time proposed. Similar issues exist for other parts of the Proposed Rules.

The Proposed Rules violate the major questions doctrine, which the Supreme Court warned EPA about in *West Virginia v. EPA* (Section VI).

- The Proposed Rules lead to the exact same result that the Supreme Court found unlawful in the Clean Power Plan: a shifting away from fossil fuel-fired generation and a dictation of what EPA views as the optimal mix of energy sources in the United States, which it lacks the authority to do.

The applicability dates for the Proposed Rules are incorrect as a matter of law (Section VII).

- EPA's original analysis in the preamble to the Proposed Rules and in the proposed regulatory text was correct. Namely, an existing source for the purposes of the Proposed Rules is a fossil fuel-fired EGU that commenced construction before January 8, 2014 (or commenced reconstruction before June 18, 2014). EPA's June 12, 2023 "Memo to the Docket" regarding applicability for existing combustion turbines is incorrect under the CAA. Combustion turbines that were constructed after January 8, 2014, and whose CO2 emissions were subject to Subpart TTTT, are "new sources" under section 111, and therefore cannot be existing sources for the purposes of these rules.

The Proposed Rules impermissibly restrict states' remaining useful life and other factors ("RULOF") determinations (Section VIII).

- EPA should not unduly restrict states' ability to examine RULOF. The Proposed Rules put too many restrictions on a state's RULOF analysis. For example, EGUs subject to a RULOF determination should be allowed to participate in an emissions trading program.
- EPA should make clear that if a state plans results in the same outcome in terms of environmental benefits that would have been achieved under EPA's presumptive level of stringency, that state plan should be approved by EPA as "satisfactory."
- States must be allowed to consider energy impacts and requirements as part of its RULOF analysis and should be allowed to give an EGU a less stringent emission limitation to preserve electric reliability.
- States should be allowed to modify an EGU's subcategory parameters to address RULOF issues.

EPA needs to assist the states by providing a model trading rule based on mass-based presumptively approvable emission limits that states can adopt (Section IX).

- EPA should issue a model trading rule for existing sources that states may opt into and that would be a fully approvable and automatic state plan. There are many policy reasons that support this approach, and it is one that EPA has followed in the past.
- EPA should not unduly restrict emissions trading. Any model rule issued by EPA should be broadly applicable across all affected fossil fuel-fired EGUs.
- EPA should provide states with alternative mass-based presumptively approvable emission limits. Mass-based limits have numerous advantages. This should be done even if EPA does not issue a model trading rule.

EPA's environmental justice analysis should examine the effects on environmental justice communities of decreased electric reliability and lack of access to affordable electricity (Section X).

- The costs of new environmental regulations are likely to fall disproportionately on lower-income households and environmental justice communities. EPA needs to consider this as part of its analysis of the Proposed Rules.
- Electric reliability problems are also most likely to be borne by environmental justice communities that will lack the means to be able to install emergency backup generation to avoid the consequences of any electric service disruptions. EPA needs to consider energy justice issues in its analysis of the Proposed Rules.
- Recent evaluations of the cap-and-trade programs, including by California as part of its Carbon Cap-and-Trade Program, show that emissions trading is unlikely to have negative environmental justice impacts and, in fact, should achieve the opposite result.
- EPA has not adequately responded to safety concerns raised by a number of environmental justice organizations.

EPA's Integrated Planning Model ("IPM") analysis on which the Proposed Rules rely is deeply flawed (Section XI).

- EPA's base case from which the Proposed Rules are evaluated contains unrealistic and wildly optimistic assumptions about the impact of the IRA on coal retirements and CCS retrofits, as well as the amount of renewables that would replace the retired generation. EPA's base case is inconsistent with every other available model, including the one published by the Energy Information Administration ("EIA").
- IPM's updated baseline fails to consider grid reliability issues confronting the electric power sector, particularly for 2030. The IPM modeling replaces dispatchable power with non-dispatchable renewable generation without any consideration of the different nature of these two types of generating assets. EPA also fails to consider factors relating to capacity in queues, length of time in queues, and project completion of renewables.
- EPA's 2030 "base case," which projects CCS would be used by 2030 at 27 coal-fired units (about 9 gigawatts ("GW") of capacity), contains substantial errors and unreasonable assumptions.

EPA failed to provide sufficient time for public comment on the Proposed Rules in violation of the CAA and the Administrative Procedure Act (Section XII).

- The time period provided by EPA for public comment on the Proposed Rules was insufficient and violated the CAA and the Administrative Procedure Act because it failed to give affected parties adequate time to develop evidence in the record to support their positions on the Proposed Rules.

- EPA ignored requests from numerous affected parties for additional time, including requests from state environmental agencies, regional transmission operators, and Congress.
- EPA improperly released new IPM data that materially changed EPA's original analysis of the Proposed Rules with a mere 21 business days left in the comment period.
- EPA provided less time for comment on the Proposed Rules, which consist of five separate rules, than it did in previous rulemakings where the rules were proposed in smaller rulemaking packages.
- EPA is not under any deadlines that would require it to shorten the comment period.

Additional items needing clarification or changes (Section XIII).

- The definition of "electric generating capacity" needs clarification. Even with EPA's recent release of a memo to the docket, a lot of confusion remains on this point.
- EPA should consider eliminating the concept of heat recovery steam generator ("HRSG") apportionment in the Proposed Rule because it is a bad policy to penalize combined cycle units that only utilize recovered waste heat to augment the output of the gas-fired turbine. The steam produced by the HRSG does not cause CO_2 emissions.
- The timing for increments of progress under the Proposed Rules should not begin to run until after a state plan has been approved by EPA.
- EPA should eliminate the proposed requirement for affected EGUs to establish a "Carbon Pollution Standards for EGUs website." This proposed requirement is burdensome, unnecessary, and inconsistent with the principles of the Paperwork Reduction Act.

III. The Proposed Rules Threaten Both the Reliability and Affordability of Electricity, and EPA Needs to Carefully Analyze this Issue More Broadly to Avoid Instability in the Electric Grid.

The electric generating industry is in a period of transition toward increased use of renewable energy and decreasing use of fossil fuel-fired generation. The retirement of coal-fired EGUs has been occurring at a rapid pace. From 2010 to 2019, about 40 percent of U.S. coal generating capacity closed.[9] According to the EIA, 14.9 gigawatts ("GW") of generating capacity was scheduled to retire

[9] Phys.org, *50 US coal power plants shut under Trump* (May 9, 2019), https://phys.org/news/2019-05-coal-power-trump.html (noting the closure of 289 plants between 2010 and 2019).

in the United States in 2022, with all of those retirements coming from baseload capacity[10] (85 percent from coal, 8 percent from natural gas, and 5 percent from nuclear).[11] These numbers are only accelerating in 2023. The EIA estimates that 15.6 GW of electric generating capacity will retire this year with 98 percent of those retirements being fossil fuel-fired plants (58 percent from coal and 40 percent from natural gas).[12] Notably, retirements of natural gas-fired plants, which also provide baseload power, are showing a tremendous increase in 2023, with 6.2 GW of natural gas-fired generation planning to retire.[13]

The high pace of coal-fired EGU retirements has strained the grid and threatened reliability. The President and Chief Executive Officer of NERC recently testified before Congress that while NERC finds "that the energy transformation can be navigated in a reliable way," it "is concerned that the pace of change is overtaking the reliability needs of the system. Unless reliability and resilience are appropriately prioritized, current trends indicate the potential for more frequent and

[10] Baseload capacity consists of those EGUs that provide firm, dispatchable capacity that can be ready to serve electric load whenever needed. This is in contrast to intermittent resources such as wind and solar that are available only when the wind blows and the sun shines. EPA needs to differentiate and understand the differences between *energy* and *capacity*. At a minimum, an electricity transmission system requires adequate dispatchable EGU capacity to meet peak demand. Intermittent EGU resources are not "dispatchable"; they are an energy source to a transmission system, not a capacity resource. Intermittent resources tend to be low-emitting units that are good for displacing emissions from dispatchable units, but they do not replace the need for reliable capacity that comes from baseload generation.

[11] EIA, Today in Energy, *Coal will account for 85% of U.S. electric generating capacity retirements in 2022* (Jan. 11, 2022), https://www.eia.gov/todayinenergy/detail.php?id=50838.

[12] EIA, Today in Energy, *Coal and natural gas plants will account for 98% of U.S. capacity retirements in 2023* (Feb. 7, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55439.

[13] *Id.*

more serious long duration reliability disruptions, including the possibility of national consequence events."[14]

In its 2022-2023 Winter Reliability Assessment, NERC expressed concern that "[a] large portion of the North American [bulk power system] is at risk of insufficient electricity supplies during peak winter conditions."[15] For the Texas ERCOT region, NERC worried that EPA's coal ash disposal regulations "could impact the availability of two coal-fired generation units (combined total of 1,477 megawatts ("MW")) in the last weeks of winter. These units could be important resources during extreme conditions…."[16] Similarly, MISO (the independent system operator in the Midwest) has had its reserve margins fall by over 5 percent since the winter of 2021-2022 because of nuclear and coal-fired EGU retirements.[17] Further retirements within MISO as a result of the Proposed Rules will exacerbate the problem. One of NERC's recommendations is that "regulators should … take steps to delay imminent generation retirements if essential to reliability."[18] NERC's 2022 Summer Reliability Assessment expressed similar reliability concerns, especially in MISO.[19]

NERC's assessment of reliability in North America did not improve with its 2023 Summer Reliability Assessment. NERC found nearly the entire United States to be at an elevated risk for

[14] Testimony of J.B. Robb, President and CEO, NERC, Before the Senate Committee on Energy and Natural Resources at 1 (June 1, 2023), https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11.

[15] NERC, 2022-2023 Winter Reliability Assessment at 4 (Nov. 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

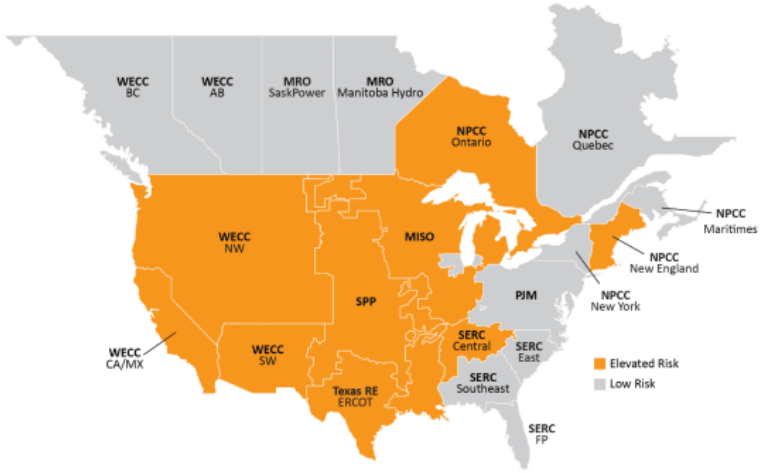
[16] *Id.*

[17] *Id.*

[18] *Id.* at 5.

[19] NERC, 2022 Summer Reliability Assessment at 4 (May 2022) (noting MISO is at a "high risk of energy emergencies during peak summer conditions"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.

having insufficient operating reserves during periods of more extreme summer conditions.[20] Figure 1 from NERC's 2023 Reliability Assessment is reproduced below.[21] The areas highlighted in orange are at elevated risk.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

NERC also identified EPA's Good Neighbor Plan as presenting reliability issues because "[c]oal and natural gas-fired generators in states affected by the Good Neighbor Plan will likely meet tighter emissions restrictions primarily by limiting hours of operation in this first year of implementation rather than through adding emissions control equipment."[22] NERC cautioned regional operators, grid operators, and balancing authorities "to be vigilant for emissions rule constraints that affect generator dispatchability," and explained that "[s]tate regulators and industry

[20] NERC, 2023 Summer Reliability Assessment at 5-6 (May 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

[21] *Id.* at 5.

[22] *Id.*

should have protocols in place at the start of summer for managing emergent requests" for waivers.[23]

NERC's specific mention of the Good Neighbor Plan, which will go into effect on August 4, 2023, should remind EPA that its regulations have an effect on retirements and utilization of electric generating units. In addressing how reliability and affordability of electricity will be affected by the Proposed Rules, the Office of Air and Radiation cannot look at the proposal in a silo or fail to look at what its sister offices, such as the Office of Water and Office of Solid Waste and Emergency Response, are proposing. In addition to the recently finalized Good Neighbor Plan, EPA has numerous other proposed or recently finalized regulations that will lead to further fossil fuel-fired EGU retirements in the electric generating industry—and therefore an effect on the reliability and affordability of electricity. These rules include EPA's Effluent Limitation Guidelines ("ELG") and Coal Combustion Residuals ("CCR") rulemaking.[24]

These rulemakings are complex and contain various retirement and compliance dates. This makes compliance decisions for the owners and operators of affected EGUs complicated and difficult. A sampling of the compliance dates and retirements dates included in the Proposed Rules, the ELG rules, and the CCR rules illustrates the problem:

- 2020 CCR Rule Revisions: Retirement dates of 10/17/23 or 10/17/28
- 2020 ELG Rule: Retirement date of 12/31/38
- 2023 ELG Proposal: Retirement date of 12/31/32
- 2023 Proposed GHG Rules: Retirement dates of 12/31/31, 12/31/34, or 12/31/39
- 2020 CCR Rule Revisions: Compliance date of 10/15/23
- 2020 ELG Rule: Compliance date of 12/31/25
- 2023 ELG Proposal: Compliance date of 12/31/29
- 2023 Proposed GHG Rules: Compliance date of 12/31/29

[23] *Id.*

[24] 88 Fed. Reg. 18,824 (Mar. 29, 2023) (EPA Office of Water proposed rule for supplemental effluent limitations guidelines for the steam electric power generating point source category); 88 Fed Reg. 31,982 (May 18, 2023) (EPA Office of Land and Emergency Management proposed rule addressing the disposal of coal combustion residuals from electric utilities).

EPA should consider harmonizing these compliance dates and retirement dates to make them consistent across all of these rules.[25]

In addition to performing a more holistic analysis of the impact of the Proposed Rules, EPA also needs to consider how efforts outside environmental regulations may affect electric reliability and affordability such as regulations that will result in exponential increases in the use of electric vehicles in the transportation sector and analyze how the Proposed Rules may affect the ability of electric generators to meet that increased load on the electric system in the United States.[26] Proposing regulations that the Agency knows will hasten the retirement of fossil fuel-fired EGUs in the United States (thus decreasing the availability of baseload generation) while simultaneously proposing regulations that will increase the need for electricity in the United States is ill-conceived and poor public policy. EPA needs to examine this issue thoroughly. Failure to do so could result in erosion of public support for EPA's greenhouse gas programs.

The increased retirements of fossil fuel-fired EGUs in recent years has unequivocally decreased electric reliability. This can be seen in the exponential increase in requests to DOE under section 202(c) of the Federal Power Act to suspend compliance with environmental regulations in order to preserve the reliability of the bulk electric power system. From 2000 to 2019, DOE issued 8 orders under section 202(c).[27] That number of orders, which took place over a 20-year period of

---

[25] What EPA should *not* do, is what it did in this rulemaking: adopt such unrealistic and wildly optimistic assumptions regarding the impact of the IRA, in a transparent attempt to make the impact of the Proposed Rules on fossil fuel-fired EGU retirements much less than it plainly will be. *See infra* Section XI.

[26] *See, e.g.*, 88 Fed. Reg. 29,184 (May 5, 2023) (EPA proposed multi-pollutant emissions standards for model years 2027 and later light-duty and medium-duty vehicles); California's Advanced Clean Cars II regulations, https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program.

[27] DOE, Office of Cybersecurity, Energy Security, and Emergency Response, *DOE's Use of Federal Power Act Emergency Authority – Archived*, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority-archived.

time, was nearly matched in 2022 alone, when 7 such emergency orders were issued.[28] Eleven emergency orders have been issued by DOE since 2020.[29]

Even before EPA issued the Proposed Rules, the EIA was releasing information showing that concerns about reliability will only increase in the next few years as many more retirements of the remaining coal-fired EGUs are expected. The EIA reports that 28 percent of the remaining coal-fired EGUs will retire by 2035,[30] with nearly all of those retirements taking place by the end of 2029.[31] Nearly 10,000 MW will be retired in 2028 alone, driven primarily by compliance with EPA's ELG rules, which limit waste water discharges from power plants.[32] The EIA says that cost of compliance with the ELG rules, which involve significant capital investment, is "likely influencing the decision to retire some of these coal-fired units."[33]

Unfortunately, the Proposed Rules compound the problem of significant capital investments either forcing early retirement or significantly curtailing the amount an EGU may run. This will further strain electric reliability, raise health and safety issues resulting from electric service disruptions, and increase the cost of electricity. These effects run the risk of undermining public support for GHG reducing programs and conflict with the purpose of the CAA "to promote the public health and welfare and the productive capacity of [the nation's] population."[34] The Proposed

---

[28] DOE, Office of Cybersecurity, Energy Security, and Emergency Response, *DOE's Use of Federal Power Act Emergency Authority*, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.

[29] *Id.*

[30] EIA, Today in Energy, *Of the operating U.S. coal-fired power plants, 28% plan to retire by 2035* (Dec. 15, 2021), https://www.eia.gov/todayinenergy/detail.php?id=50658.

[31] EIA, Today in Energy, *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.

[32] *Id.*

[33] *Id.*

[34] CAA § 101(b)(1); 42 U.S.C. § 7401(b)(1).

Rules require significant capital investment into coal-fired EGUs unless they commit to retire prior to 2032 (i.e., be subcategorized as an "imminent-term" unit)[35] or adopt a severe limit on their capacity factor by 2030 and commit to retire by 2035 (i.e., be subcategorized as a "near-term" unit).[36] Any coal-fired EGU that intends to operate after January 1, 2035, but retire before January 1, 2040, (i.e., a unit subcategorized as a "medium-term" unit), will need to make a substantial capital investment in the unit unless the unit already has access to natural gas and the capability to co-fire natural gas at high levels.[37] For any unit that intends to operate after January 1, 2040 (i.e., a unit subcategorized as a "long-term" unit), it must accelerate these capital investments and complete them by January 1, 2030.[38] Further, any medium-term unit must meet a host of interim "increments of progress" by that date.[39] All of these requirements will almost certainly hasten the retirement of additional coal-fired EGU capacity beyond that anticipated by the EIA.

The Proposed Rules will also result in capacity factor restrictions on large, frequently used combustion turbines, which could also have a deleterious effect on electric reliability—particularly in areas that heavily rely on combustion turbines for baseload generation such as Texas. Any natural gas-fired combustion turbine that is greater than 300 MW in size and that operates at a capacity factor greater than 50 percent[40] will need to make significant capital investment into those units by

[35] Proposed 40 C.F.R. §§ 60.5740b(a)(1)(D), (a)(3)(i)(C); 60.5775b(c)(4).

[36] *Id.* §§ 60.5740b(a)(1)(C), (a)(3)(i)(B); 60.5775b(c)(3).

[37] *Id.* §§ 60.5740b(a)(1)(B), (a)(3)(i)(A); 60.5775b(c)(2).

[38] *Id.* §§ 60.5740b(a)(1)(A), (a)(4)(viii)(A); 60.5775b(c)(1).

[39] *Id.* § 60.5740b(a)(4)(viii)(A).

[40] *Id.* § 60.5850b(a) (excluding from the Proposed Rules natural gas fired stationary combustion turbines with that are equal to or less than 300 MW and that operate at an annual capacity factor less than or equal to 50 percent).

2032 (if the hydrogen option is selected)[41] or by 2035 (if the CCS option is selected).[42] As discussed in further detail in Sections IV.B and IV.C of these comments, neither of these technologies currently meets the legal standard under section 111 of the CAA that a system of emission reduction be adequately demonstrated or achievable. That leaves owners and operators of EGUs stuck between a rock and a hard place: they can either invest significant sums of money into unproven technologies or they can operate these units at half or less of their capacity and run the risk of there not being an adequate supply of electricity to serve their customers.

As EPA considers how to proceed on the Proposed Rules, it should coordinate and collaborate with its other peer agencies, such as DOE and FERC, to ensure that electricity remains reliable and affordable. Indeed, EPA and DOE recently entered into a Memorandum of Understanding ("MOU") that recognizes the importance of coordination between the two agencies "at a time of significant dynamism in the electric power sector."[43] EPA needs to follow the framework identified in the MOU and conduct an analysis of the effect of the Proposed Rules on reliability. Concerned that reliability issues have not been adequately analyzed in connection with the Proposed Rules, the Ranking Members of the Senate Committee on Energy and Natural Resources and the Committee on Environment and Public Works have also called on DOE to hold a series of technical conferences to analyze the impact of the Proposed Rules on electric reliability.[44]

---

[41] *Id.* § 60.5740b(a)(4)(viii)(B).

[42] *Id.* § 60.5740b(a)(4)(viii)(C).

[43] DOE, EPA, Joint Memorandum on Interagency Communication and Consultation on Electric Reliability (Mar. 10, 2023); https://www.epa.gov/power-sector/electric-reliability-mou; *see also* DOE, Office of Policy, U.S. Department of Energy and Environmental Protection Agency Partner to Support Reliable Electricity: New Memorandum of Understanding Supports Reliability of Nation's Power System as Energy Sector Invests in Clean Energy Opportunities, https://www.energy.gov/policy/articles/us-department-energy-and-environmental-protection-agency-partner-support-reliable.

[44] Letter to FERC Chairman W. Phillips and Commissioners J. Danly, A. Clements, and M. Christie from Sen. J. Barrasso, Ranking Member, U.S. Senate Committee on Energy and Natural Resources

In addition, EPA needs to make sure that any final rule provides states with adequate time to consult with their power sector regulators, such as public service commissions, for the purpose of ensuring reliability and affordability. EPA should pay careful attention to comments filed by the regional transmission operators, independent system operators, regional reliability authorities, NERC, and state utility commissions regarding reliability.

Finally, EPA should consider providing a safety valve exemption for EGUs that adopt capacity factor restrictions in connection with these Proposed Rules that would allow those units to operate beyond those restrictions for the purpose of stabilizing the grid during periods of extreme load (such as during periods of excessive cold or heat or when baseload units go offline). EPA did this in the Clean Power Plan and should do so here.[45]

IV. The Proposed Rules Violate the Requirements of Section 111 of the CAA.

A. Legal Standard for Performance Standards under Section 111

Regulation of new sources in a source category under section 111(b) of the CAA is a prerequisite to regulation of existing sources under section 111(d). Section 111 of the CAA directs EPA to list categories of stationary sources that it determines contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.[46] After a source category has been listed by EPA, the Agency is required to establish NSPS for new and modified sources for the category pursuant to CAA section 111(b).[47] Once EPA has issued an NSPS pursuant to 111(b), in certain limited situations that exist with regard to GHG emissions from EGUs, EPA is then authorized to issue emission guidelines under section 111(d) that will guide states in setting

---

and Sen. S.M. Capito, Ranking Member, U.S. Senate Committee on Environment and Public Works (June 30, 2023) (Attachment B to these comments).

[45] 80 Fed. Reg. 64,662, 64,877-79 (Oct. 23, 2015).

[46] CAA § 111(b)(1)(A), 42 U.S.C. § 7411(b)(1)(A).

[47] *Id.* § 111(b)(1)(B), 42 U.S.C. § 7411(b)(1)(B).

standards of performance for existing sources in the category.[48] EPA issued standards of performance for GHG emissions from new, modified, and reconstructed EGUs under section 111(b) in 2015.[49] The Subpart TTTT regulations cover both steam generating units and combustion turbines.[50] The Proposed Rules seek to revise the Subpart TTTT regulations and to establish section 111(d) emission regulations for both steam generating units and combustion turbines.[51]

For the purposes of section 111, a "standard of performance" is:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[52]

Under the plain language of the CAA, therefore, an NSPS must be "achievable" by the regulated new sources within the designated source category using the BSER that has been "adequately demonstrated" for the new sources to which the standard applies, considering cost and other factors. An NSPS must require an emission limitation on a continuous basis through establishment of a numerical emissions limit and a compliance protocol to measure those emissions. Only in

[48] *Id.* § 111(d)(1), 42 U.S.C. § 7411(d)(1).

[49] 80 Fed. Reg. 64,510 (Oct. 23, 2015) ("Subpart TTTT").

[50] *Id.* Numerous parties filed petitions for review in the D.C. Circuit challenging the NSPS for steam generating units, which found partial CCS to be the best system of emission reduction ("BSER") for new steam generating units as being unlawful, while no one challenged the NSPS for combustion turbines. *See North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir.). This litigation has been stayed pending EPA's administrative review of the 2015 NSPS.

[51] EPA previously promulgated emission guidelines to address GHG emissions from existing EGUs in the Clean Power Plan (for both combustion turbines and steam generating units) and the Affordable Clean Energy Rule (for steam generating units only). Neither rule was ever implemented, as EPA discusses in the preamble to the Proposed Rules. 88 Fed. Reg. at 33,268-70, 33,271.

[52] CAA § 111(a)(1), 42 U.S.C. 7411(a)(1).

circumstances where it is not feasible to establish an enforceable numerical standard may EPA promulgate a design or work practice standard.[53]

In developing an NSPS for a type of new source, EPA must engage in a three-step analysis.[54] First, EPA identifies a system or systems of emission reduction that have been "adequately demonstrated" for that type of source. Second, EPA determines what emission levels are "achievable" by such sources using the adequately demonstrated system or systems.[55] Third, after this determination, EPA "must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations."[56] Although an NSPS must be based on the performance of BSER incorporated into the design of the type of source to which the standard applies, it may not require individual new sources to install or operate the particular technology or system identified as BSER to meet the numerical performance level established by the NSPS.[57]

1. "Adequately Demonstrated"

Any control technology selected as BSER must first be a technology that has been "adequately demonstrated."[58] The D.C. Circuit has held that a system that has been adequately demonstrated is "one which has been *shown* to be reasonably *reliable*, reasonably *efficient*, and which

---

[53] *Id.* § 111(h), 42 U.S.C. § 7411(h).

[54] *See Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).

[55] The "adequately demonstrated" and "achievable" criteria are separate and distinct requirements for an NSPS that apply to the selected control technology and the actual emission standard, respectively. "It is the system which must be adequately demonstrated and the standard which must be achievable." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).

[56] *Id.*

[57] CAA § 111(b)(5), 42 U.S.C. § 7411(b)(5).

[58] EPA is further restricted under the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) ("EPAct") from considering in the "adequately demonstrated" determination technologies that receive certain types of funding from DOE and that receive certain types of tax credits.

can reasonably be expected to serve the interests of pollution control *without becoming exorbitantly costly* in an economic or environmental way."[59] Thus, an adequately demonstrated system must have an operational history that shows more than mere technical feasibility: it must be dependable and effective, available at a reasonable cost for individual sources, and based on actual operating experience within the source category or at sufficiently similar sources.

Although EPA has some discretion to extrapolate from other industries in determining whether a technology demonstrated in one industry is adequately demonstrated for another industry, that discretion is significantly limited. EPA may look to a technology's performance in another industry only if experience in that context is sufficiently representative of operations of sources in the category to be regulated.[60] Any EPA extrapolations from one category to another are "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry" or "mere speculation or conjecture."[61] This latitude is further narrowed by the fact that NSPS are effective upon proposal and provide no "'lead time"' for further technological development.[62]

To be adequately demonstrated for all sources within a category or subcategory, a technology must be available for each source type to which the standard will apply. For example, in its 2005 proposed revisions to the NSPS for Subpart Da units, EPA rejected supercritical boiler design, integrated gasification combined cycle technology, and the use of clean fuels as potential bases for its revised standards due in part to the unavailability of these options across source types

---

[59] *Essex Chem. Corp.*, 486 F.2d at 433 (emphases added); *see also Nat. Res. Def. Council v. Thomas*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986).

[60] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (per curiam).

[61] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973); *see also id.* at 389 ("The essential question is whether the mandated standards can be met by a particular industry for which they are set, and this can typically be decided on the basis of information concerning that industry alone."); *Lignite Energy Council*, 198 F.3d at 934.

[62] *Portland Cement Ass'n*, 486 F.2d at 391-92.

to which the standards would apply.[63] In assessing adequate demonstration, courts often consider issues such as whether: (i) sufficient implementation experience has accrued at full-scale facilities; (ii) data from prototype facilities or other industries are sufficiently representative to warrant extrapolation to the source category; (iii) experience has accrued with all fuel types; and (iv) unresolved issues remain regarding waste disposal or other harmful environmental effects.[64]

2. "Achievable"

Once EPA identifies an "adequately demonstrated" system, it then must determine what levels of emissions are "achievable" by individual sources applying that system. EPA must explain how the standard "is achievable under the range of relevant conditions which may affect the emissions to be regulated," including "under most adverse conditions which can reasonably be expected to recur."[65] A standard that applies to all new sources in a category must be achievable "for the industry as a whole" and not just for a subset of sources.[66] As with determining whether a technology is adequately demonstrated, EPA may not base its determination that a standard is achievable on "mere speculation or conjecture."[67]

In order to show that a given emission level is "achievable" by a system of emission reduction, EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the

[63] 70 Fed. Reg. 9706, 9712, 9714, 9715 (Feb. 28, 2005).

[64] *See Lignite Energy Council*, 198 F.3d at 934; *Sierra Club*, 657 F.2d at 341 n.157; *Essex Chem. Corp.*, 486 F.2d at 438-39.

[65] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n.46, 433 (D.C. Cir. 1980).

[66] *Id.* at 431.

[67] *Lignite Energy Council*, 198 F.3d at 934.

standard."[68] In other words, the validity of EPA's achievability determination depends on how fully it has accounted for the variations among sources in the regulated category that could affect emission levels. Courts have repeatedly rejected NSPS that EPA deemed "achievable" based on test data from a narrow set of sample sources that did not represent the full range of relevant variability among sources to which the standard will apply.[69] In these cases, courts have required EPA to consider such variables as source type, feedstock or fuel type, the relationship between emissions generated and the effectiveness of control technology, and regional variations.[70] An NSPS "establishes what every source can achieve, not the best that a source could do."[71] It is intended to represent the "least common denominator" of control standards that can "be reasonably achieved by [a] new source *anywhere* in the nation."[72]

3. Consideration of Statutory Factors for "Best" Adequately Demonstrated System

After EPA has identified the emission levels achievable through the use of adequately demonstrated technology, the Agency selects a standard from the range of demonstrated technologies that "represents the best balance of economic, environmental, and energy considerations."[73] At this stage, in addition to the statutory factors of "the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements,"[74] EPA

---

[68] *Sierra Club*, 657 F.2d at 377 (quoting *Nat'l Lime Ass'n*, 627 F.2d at 433).

[69] *See, e.g.*, *Nat'l Lime Ass'n*, 627 F.2d at 432; *Portland Cement Ass'n*, 486 F.2d at 396, 402.

[70] *Nat'l Lime Ass'n*, 627 F.2d at 435-42.

[71] Letter from Gary McCutchen, Chief, New Source Review Section, EPA Office of Air Quality Planning and Standards, to Richard E. Grusnick, Chief, Air Division, Ala. Dep't of Envtl. Mgmt. at 1 (July 28, 1987), https://www.epa.gov/sites/production/files/2015-07/documents/crucial.pdf ("McCutchen Letter").

[72] *Id.* (emphasis added).

[73] *Sierra Club*, 657 F.2d at 330.

[74] CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1).

may consider a proposed standard's projected emission reductions and its potential to encourage (rather than mandate) technological innovation.[75]

Moreover, in determining BSER, EPA must ensure that standards do "not give a competitive advantage to one State over another in attracting industry."[76] For example, in *Sierra Club*, the D.C. Circuit observed that "an efficient water intensive technology … might be 'best' in the East where water is plentiful, but environmentally disastrous in the water-scarce West."[77] Thus, the water intensive technology could not be selected as the BSER because it would have had the effect of precluding construction of new sources in states that lack the resources necessary (in this case, water) to allow compliance with the standard at a reasonable cost.

EPA must account for these factors at the plant level and may consider them "at the national and regional levels and over time."[78] The Agency's discretion, however, to consider costs and environmental or energy impacts at the national level does not permit it to disregard these impacts in selecting among the technologies that are demonstrated for individual sources. The D.C. Circuit made clear in *Sierra Club* that the CAA authorizes EPA to examine the national scale in addition to—not instead of—assessing a standard's impact on individual sources.[79] Thus, EPA may not set an NSPS based on national-scale considerations that would impose unreasonable costs, environmental impacts, or energy requirements at the level of individual plants.

EPA may not rely on consideration of costs and environmental or energy impacts on a national level to justify a standard of performance that is more stringent than would be permitted

[75] *Sierra Club*, 657 F.2d at 326, 347.

[76] *Id.* at 325.

[77] *Id.* at 330.

[78] *Id.*

[79] *Id.*

based on source-level factors used to select among the demonstrated technologies. The CAA allows EPA to account for these impacts as a safety valve to prevent regulators from adopting standards of performance that cause more economic or environmental harm than they prevent, and not as a method for the Agency to demand additional emission reductions.[80] The Agency may consider these factors only after ruling out emission levels that are not achievable based on adequately demonstrated technology. Accordingly, EPA cannot rely on purported national or regional benefits to justify standards of performance that are unachievable, based on inadequately demonstrated technology, or otherwise unreasonable at the individual source level.

B. CCS Does Not Meet the Requirements of Section 111.

CCS is a promising technology that is making advancements through a variety of pilot projects throughout the United States. Some PGen members are actively investigating the feasibility of CCS at a portion of their facilities and hope to be able to rely on this technology in the future to reduce GHG emissions. While progress is being made, however, EPA is incorrect in its assertion that the technology has developed enough in the power sector to cross the regulatory threshold into being "adequately demonstrated," as required for any BSER under the CAA. There is insufficient experience at this time with CCS in commercial operation to find that the technology is currently feasible or reliable for widespread application in the electric generation industry—particularly at commercial scale and especially for utility combustion turbines where the technology has yet to be applied. Further, even if the technology were ready for more widespread deployment (which it is not), several issues remain that technological development cannot resolve, including geographical constraints, access to water, deficient pipeline infrastructure, parasitic load, and cost that prevent the technology from being properly selected as a BSER.

[80] *See, e.g.*, *id.*

EPA proposes that CCS be one of two BSERs identified for new base load stationary combustion turbines and for existing large and frequently used stationary combustion turbines.[81] The selection of CCS as a BSER for these EGUs violates section 111 of the CAA because it fails every prong of the three-step test for determining a BSER: (1) CCS is not adequately demonstrated at fossil fuel-fired EGUs; (2) any emission standard based on CCS at these EGUs is not achievable; and (3) even if CCS were adequately demonstrated and achievable for these EGUs (which it is not), it has numerous factors that prohibit its being considered "best." Each of these is discussed further below.

1. CCS Is Not Adequately Demonstrated at Fossil Fuel-Fired EGUs.

a. Combustion Turbines

EPA proposes to find CCS adequately demonstrated for use at natural gas combined cycle ("NGCC") combustion turbines based on two projects: the Bellingham Energy Center in Massachusetts, and the Peterhead Power Station in Scotland.[82] Neither of these projects supports that determination. At the Bellingham Energy Center, CCS was applied to an existing combined cycle turbine. The 40-megawatt ("MW") slipstream capture facility operated from 1991 to 2005 and captured 85 to 95 percent of the CO_2 in the slipstream for use in the food industry.[83] A slipstream capture facility is not comparable to the amount of capture that is required at large fossil fuel-fired EGUs. Although the slipstream process arrangement is "a useful means for research and development," it "does not link the reliability of the host process to the CO_2 capture technology—

[81] 88 Fed. Reg. at 33,288-316 (proposed BSER determination for new baseload stationary combustion turbines); *id.* at 33,362-69 (proposed BSER determination for existing large and frequently used stationary combustion turbines). The other BSER for base load combustion turbines is hydrogen co-firing, which PGen discusses *infra* in Section IV.C.

[82] *Id.* at 33,292.

[83] *Id.* Because this project involved utilization of the captured CO_2 onsite for use in the food industry, it did not involve any pipeline transport or storage component.

and thus cannot reflect the conditions for 24x7 utility power generation demonstration."[84] In addition, there are no data provided to describe the experience at Bellingham.[85] For example, it is not known whether operation was continuous or intermittent. As the Cichanowicz Technical Report notes, "[i]f periods of 85-95% CO_2 removal are interspersed with lower targets, this experience does not support BSER for utility application."[86]

The second project EPA relies on—the Peterhead Power Station in Scotland—"is in the planning stages of development" and is not yet in operation.[87] A plant that is not yet operational cannot serve as the basis for an adequately demonstrated determination because the technology has not yet "been shown to be reasonably reliable, reasonably efficient, and … reasonably … expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[88] To be considered as an adequately demonstrated technology, there must be an operational history that shows more than mere technical feasibility and the determination must be based on actual operating experience within the source category or at sufficiently similar sources.[89]

---

[84] J.E. Cichanowicz, M.C. Hein, Technical Comments on New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule at 3 n.7 (Aug. 27, 2023) ("Cichanowicz Technical Report") (Attachment C to these comments).

[85] There is a DOE "fact sheet" on this project, but it only reports that the unit operated from 1991 to 2005 and that CO_2 removal of 85 to 95 percent was achieved. DOE, Carbon Capture Opportunities for Natural Gas Fired Power Systems, https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.

[86] Cichanowicz Technical Report at 4.

[87] 88 Fed. Reg. at 33,292.

[88] *Essex Chem. Corp.*, 486 F.2d at 433; *see also NRDC v. Thomas*, 805 F.2d at 428 n.30.

[89] EPA also mentions "several *planned* projects using the NET Power Cycle" and "several *announced* commercial projects proposing to use the NET Power Cycle" in its discussion of adequate demonstration for CCS at combustion turbines. 88 Fed. Reg. at 33,292 (emphases added). These projects, none of which are in operation, cannot support an adequate demonstration determination.

EPA properly recognizes that the EPAct "constrained how the EPA could rely on [EPAct] assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111."[90] The specific language of EPAct that constrains EPA states that "[n]o technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [] for purposes of section 111 of the Clean Air Act."[91] Congress was clear. EPA may not base an adequately demonstrated determination on technologies that receive monies under EPAct. EPA is incorrect in its interpretation first set forth in the Clean Power Plan and restated in the Proposed Rules that it is "'not preclude[d] … from relying on the experience of such facilities in conjunction with other information.'"[92]

Seemingly recognizing this, EPA states that its adequately demonstrated determination does not rest on any EPAct funded technologies.[93] The Agency then goes on, however, to list eleven EPAct funded projects at stationary combustion turbines that it says "corroborate" its adequately demonstrated finding.[94] Even if these projects could be considered—which they cannot—they would not support an adequately demonstrated determination by EPA. All of these projects have one thing in common: none of them are actually constructed and in operation. EPA notes the following with regard to these projects: (1) General Electric project in Bucks, Alabama, "is *targeting* commercial deployment *by 2030*"; (2) Wood Environmental & Infrastructure Solutions in Blue Bell,

[90] *Id.* at 33,291.

[91] EPAct § 402(i), 42 U.S.C. § 15962(a). Similar EPAct language was codified in the Internal Revenue Code and restricts EPA from considering technology that received tax credits under the EPAct. EPAct § 1307(b), 26 U.S.C. § 48A(g); *see also* 88 Fed. Reg. at 33,291 n.240.

[92] 88 Fed. Reg. at 33,291 (quoting 80 Fed. Reg. at 64,541-42).

[93] *Id.* at 33,292.

[94] *Id.* at 33,292-93.

Pennsylvania, awarded funds "to complete an *engineering design study*" for a project that "*aim[s]* … to reduce CO_2 emissions by 95 percent … from several plants"; (3) General Electric Research in Niskayuna, New York, awarded funds to "*develop* a design to capture 95 percent of CO_2 from NGCC flue gas"; (4) SRI International in Menlo Park, California, awarded funds "to *design, build, and test* a technology that can capture at least 95 percent of CO_2"; (5) CORMETECH, Inc. in Charlotte, North Carolina, awarded funds "to further *develop, optimize, and test* a new, lower cost technology to capture CO_2 from NGCC flue gas and *improve scalability to large NGCC plants*"; (6) TDA Research, Inc. in Wheat Ridge, Colorado, awarded funds "to *build and test* a post-combustion capture process to *improve the performance* of NGCC flue gas CO_2 capture"; (7) GE Gas Power in Schenectady, New York, awarded funds "to *perform an engineering design study* to incorporate a 95 percent CO_2 capture solution for an existing NGCC site while *providing lower costs and scalability to other sites*"; (8) Electric Power Research Institute in Palo Alto, California, awarded funds "to *complete a study* to retrofit a 700-Mwe NGCC with a carbon capture system to capture 95 percent of CO_2"; (9) Gas Technology Institute in Des Plaines, Illinois, awarded funds "to *develop membrane technology* capable of capturing more than 97 percent of NGCC CO_2 flue gas"; (10) RTI International in Research Triangle Park, North Carolina, awarded funds "to *test a novel* non-aqueous solvent *technology*"; and (11) Tampa Electric Company in Tampa, Florida, awarded money "to *conduct a study* retrofitting" one of its plants "with post-combustion CO_2 capture technology *aiming* to achieve a 95 percent capture rate."[95] None of these studies and tests can support a determination by EPA that CCS is currently adequately demonstrated as a system of emission reduction for stationary combustion turbines—either at new EGUs or existing EGUs.

[95] *Id.* at 33,293 (emphases added).

EPA's determination that CCS is adequately demonstrated for new and existing combustion turbines is not grounded in any actual experience with this technology at these types of EGUs. EPA's proposed determination is unlawful because it is "based on 'crystal ball' inquiry"[96] and "mere speculation or conjecture."[97]

b. Steam Generating Units

EPA proposes to find CCS adequately demonstrated for use at existing coal-fired steam generating units and proposes this technology with 90 percent capture of CO_2 as the BSER for long-term coal-fired steam generating units and for large modifications at those units.[98] EPA's finding is based on a single project at a coal-fired steam generating unit (SaskPower's Boundary Dam Unit 3 project in Saskatchewan, Canada), two slipstream power plant projects (AES Warrior Run and AES Shady Point), and two industrial applications (the Searles Valley Minerals Soda Ash Plant and the Quest CO_2 capture facility).[99] As discussed below, these projects do not support EPA's determination.

There is only one CCS project operating in North America that is relevant to utility power generation: the SaskPower Boundary Dam Unit 3 project in Saskatchewan, Canada. The Boundary Dam project has had technical difficulties and has been underperforming.[100] In 2021, the plant captured 43 percent less CO_2 than it had the year before. SaskPower attributed this decrease to "challenges with the main CO_2 compressor motor" that forced the CCS part of the plant to go

[96] *Portland Cement*, 486 F.2d at 391.

[97] *Lignite Energy Council*, 198 F.3d at 934.

[98] 88 Fed. Reg. at 33,346-51.

[99] *Id.* at 33,291-92, 33,346-47.

[100] *See* J.P. Kay, et al., Energy & Environmental Research Center, University of North Dakota, Examination of EPA's Proposed Emission Guidelines Under 40 CFR Part 60 at 6-7 (Aug. 2023) ("EERC Report") (Attachment D to these comments).

offline for multiple months in 2021.[101] The company's data for 2021 show that the CCS facility is capturing only approximately 44 percent of its 90 percent maximum capacity—meaning more than half of the plant's CO_2 emissions are not being captured.[102] And, more importantly, meaning that EPA's proposed 90 percent capture that is part of its BSER determination for coal-fired steam generating units is not being achieved. In addition, Boundary Dam Unit 3 is relatively small—only 110 MW—and therefore is not representative of how CCS might work at a much larger scale. This is particularly important given that CCS is BSER only for long-term coal-fired steam generating units (i.e., those that will operate after January 1, 2040) and for coal-fired steam generating units that undergo a large modification. Owners and operators of coal-fired steam generating units will only be willing to invest the sums of money needed for CCS (or for a large modification) in large units that are run frequently and are needed for base load generation. Therefore, a 110 MW unit is not representative of the scale that will be needed under the Proposed Rules.

The other two power projects cited by EPA in its proposed adequately demonstrated finding are slipstream projects: AES Warrior Run and AES Shady Point. While the slipstream process arrangement is "a useful means for research and development," it "does not link the reliability of the host process to the CO_2 capture technology—and thus cannot reflect the conditions for 24x7 utility power generation demonstration."[103] Neither of these projects is anywhere close to capturing 90 percent of the CO_2 from the unit. Warrior Run, which is a 205 MW unit, captures only 10 percent of

[101] E&E News, Energy Wire, *CCS 'red flag?' World's sole coal project hits snag* (Jan. 10, 2022), https://www.eenews.net/articles/ccs-red-flag-worlds-sole-coal-project-hits-snag/.

[102] *Id.*

[103] Cichanowicz Technical Report at 3 n.7; EERC Report at 5 ("[T]he small capacity, slipstream system employed here demonstrates a small portion of the required CO_2 capture rate and has little correlation to the levels EPA would mandate under their proposed guidelines.").

its CO_2 emissions and sells them to the food and beverage industry.[104] Shady Point, which is a 350 MW unit, captures even less of its CO_2—5 percent.[105]

EPA relies on two industrial units for the remainder of its adequately demonstrated determination. These units are the Searles Valley Minerals Soda Ash Plant in Trona, California, and the Quest CO_2 capture facility in Alberta, Canada. Neither of these facilities represent large-scale utility duty. In addition, there is no evidence that either of these projects were able to achieve 90 percent capture of CO_2. EPA notes in the Proposed Rules that the Searles Valley Minerals plant captures 270,000 metric tons of CO_2 per year—but does not provide information on what percentage of emissions this represents.[106] Publicly available information shows that 800 tons per day are captured at the project, and experts note that this implies no more than a 33 percent removal rate from the smallest unit at the plant for a complete 24-hour day.[107] The Quest facility involves CCS retrofitted to three existing steam methane reformers.[108] EPA states that the Quest facility captures approximately 80 percent of the CO_2 in the produced syngas.[109] The EERC Report notes the obvious, however: "[T]he overall capture of the facility falls short of EPA's proposed 90% minimum capture rate."[110] Moreover, the Cichanowicz Technical Report notes, "[t]he effluent from this methane reforming process does not reflect combustion products, as CO2 content is elevated

[104] 88 Fed. Reg. at 33,292.

[105] *Id.*

[106] *Id.*

[107] Cichanowicz Technical Report at 3. The EERC Report estimates the capture rate to approximate 18 percent. EERC Report at 5. Either way, this is a far cry from the 90 percent capture rate EPA arbitrarily crystal-balls.

[108] 88 Fed. Reg. at 33,292.

[109] *Id.*

[110] EERC Report at 6.

compared to utility application," and while this "contribut[es] to general CCUS knowledge," it "is not a basis to designate CCUS as BSER for utility application."[111]

EPA also cites some projects as "further corroborat[ion]" that it says it did not consider as part of its adequately demonstrated analysis because of EPAct funding.[112] Even if these projects could be considered by EPA in its adequately demonstrated determination—which they cannot—they do not support EPA's proposed finding. The most notable of these EPAct projects is the Petra Nova project near Houston, Texas. The Petra Nova project, which is another slipstream project, has encountered problems. The plant, which began operation in January 2017, was designed to capture 33 percent of the CO_2 emissions from one of the units at the W.A. Parish facility. The facility missed this target by about 17 percent, capturing 3.8 million short tons of CO_2 during its first three years of operation, which was less than the 4.6 million short tons that had been expected to be captured.[113] During the time the facility operated, it experienced outages on 367 days, with the CCS facility accounting for more than one-fourth of those outages.[114] The project was also dependent on oil prices to be economically viable. The project was "impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil," and its owner at the time, NRG, placed the Petra Nova project in reserve shutdown status on May 1, 2020.[115] The Petra Nova project had "no alternate method of sequestration. Market-driven EOR alone does not adequately

---

[111] Cichanowicz Technical Report at 3.

[112] 88 Fed. Reg. at 33,292-93.

[113] Reuters, *Problems plagued U.S. CO_2 capture project before shutdown: document* (Aug. 6, 2020), https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-before-shutdown-document-idUSKCN2523K8.

[114] *Id.*

[115] NRG, Coal: Examining how we use Earth's oldest resource, https://www.nrg.com/generation/coal.html.

demonstrate CCS that will meet EPA's proposed continuous emission reduction."[116] The project, which has not operated since that time, has been sold, and the new owners have indicated plans to bring it back online later this year.[117]

EPA also mentions Plant Barry in Mobile, Alabama, which is another slipstream project on a coal-fired unit that tested a CCS unit at a 25 MW scale.[118] The size of this unit is quite small and is not a demonstration of the technology at commercial scale.

EPA's proposed determination that CCS is adequately demonstrated for modified and existing coal-fired steam generating units is unlawful because it is "based on 'crystal ball' inquiry"[119] and "mere speculation or conjecture."[120] There is no evidence that CCS technology can capture 90 percent of the CO_2 emissions from a facility that is not a slipstream facility and do so on a consistent basis. Moreover, there is no evidence that these technologies can work on large, commercial-scale EGUs.

2. EPA's Proposed NSPS for New and Modified Fossil-Fuel Fired EGUs and Presumptively Approvable Emission Limitations for Existing Fossil Fuel-Fired EGUs that Are Based on CCS Technology Are Not Achievable.

EPA has long held the position that a standard of performance under section 111 "establishes what *every* source can achieve" and is intended to represent the "least common denominator" that can "be reasonably achieved by [a] new source *anywhere* in the nation."[121] This long-held position also applies to emission guidelines for existing sources under section 111(d) of

---

[116] EERC Report at 6.

[117] *See* 88 Fed. Reg. at 33,293 & n.258 (citing a news article to note that "there are reports of plans to restart the capture system").

[118] *Id.* at 33,293.

[119] *Portland Cement*, 486 F.2d at 391.

[120] *Lignite Energy Council*, 198 F.3d at 934.

[121] McCutchen Letter at 1 (emphases added).

the CAA where EPA establishes the BSER and sets presumptively approvable performance standards for those sources. In the Proposed Rules, EPA proposes NSPS based on a BSER of use of CCS with 90 percent capture of CO_2 for new NGCC combustion turbines[122] and for modified steam generating units.[123] EPA also proposes presumptively approvable performance standards based on a BSER of use of CCS with 90 percent capture of CO_2 for existing coal-fired steam generating units that will operate after January 1, 2040,[124] and as a BSER option for existing large, frequently used combustion turbines.[125] These proposed NSPS and presumptively approvable emission limitations fail to meet the requirements under section 111 that a standard of performance be achievable "for the industry as a whole."[126]

As EPA admits in the Proposed Rule, many areas of the country do not have ready access to geologic storage for CCS. Indeed, EPA "found that there are 43 States containing areas within 100 kilometers ("km") [62 miles] from currently assessed onshore and offshore storage resources…."[127] For EGUs not immediately near a geologic storage site, the construction of a pipeline to transport the captured CO_2 is necessary in order for the performance standard to be achievable. But the cost to construct a pipeline is very expensive, permitting is a years-long process, and pipelines are met with increasing resistance making permitting in many cases impossible.[128] Indeed, some PGen

[122] 88 Fed. Reg. at 33,325, Table 3.

[123] *Id.* at 33,335.

[124] *Id.* at 33,359, Table 5.

[125] *Id.* at 33,366-69.

[126] *National Lime*, 627 F.2d at 431.

[127] 88 Fed. Reg. at 33,298. The EERC moreover shows that EPA's assessment of suitable geologic sequestration site availability is incorrect and that, based on the U.S. Geological Survey ("USGS"), "more and longer pipelines will be needed to transport captured CO_2 to feasible storage locations." EERC Report at 9.

[128] *See, e.g.*, I. Penn, NY TIMES, *Atlantic Coast Pipeline Canceled as Delays and Costs Mount* (July 5, 2020), https://www.nytimes.com/2020/07/05/business/atlantic-coast-pipeline-cancel-dominion-energy-berkshire-hathaway.html; C. Davenport, NY TIMES, *Mountain Valley Pipeline Halted as Legal Wrangling*

members have experienced pipeline construction costs in the range of $4 to $10 million per mile. Under EPA's own facts, this means that in 7 States, the owners and operators of EGUs will need to construct a pipeline that is at least 62 miles long—with a *starting* cost ranging between $248 and $620 million dollars that will only increase with every additional mile.

EPA's "solution" to this achievability problem is to suggest that "States that may not have geologic sequestration sites may be served by new generation, including new base load combustion turbines, built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines."[129] While this might be conceivable for new EGUs, it is faulty on two levels. First, constructing transmission lines is also expensive, takes years to permit, and is often met with public resistance.[130] Second, and more importantly, this "give[s] a competitive advantage to one State over another in attracting industry," in violation of section 111.[131] And this "solution" is completely unworkable for existing EGUs, unless the owner or operator wants to prematurely retire an EGU and construct a new one near geologic storage—leading to a state without geologic storage being harmed twice (once when a plant in its borders closes and again when the new construction takes place in another state).

Heats Up (July 12, 2023), https://www.nytimes.com/2023/07/12/climate/mountain-valley-pipeline-courts.html; A. Liptak and A. VanSickle, NY TIMES, *Supreme Court Clears the Way for Pipeline as Appeal Moves Forward* (July 27, 2023), https://www.nytimes.com/2023/07/27/us/supreme-court-mountain-valley-pipeline.html; *see also* W. Morris and J. Weeda, Analysis of Post Combustion CO_2 Capture, Transport and Storage Costs in the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule at 4 (Aug. 3, 2023) ("Morris CCS Report") (Attachment E to these comments).

[129] 88 Fed. Reg. at 33,298.

[130] J. Weeda, Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on Generation Resource Adequacy and the Need for Transmission Alternatives at 6 (Aug. 3, 2023) ("The experience of the utility sector in recent years shows that building transmission is a challenging multi-year process, and in the more populated areas, it can be nearly impossible.") ("Weeda Report") (Attachment F to these comments).

[131] *Sierra Club*, 657 F.2d at 325.

A recent Congressional Research Service report found that there are currently approximately 5,000 miles of pipelines in the United States to transport CO_2.[132] But this is an infinitesimal fraction of what is needed. That report found that a recent study suggests that to achieve national goals for GHG reduction would require an additional 66,000 miles of pipelines by 2050, at a cost of "some $170 billion in new capital investment."[133] EPA glosses over the difficulties and hurdles involved in constructing this pipeline network in the Proposed Rules. The Agency also glosses over safety issues for these pipelines, noting almost as an aside that there was a failure of a CO_2 pipeline in Satartia, Mississippi in 2020 and that the Pipeline Hazardous Materials Safety Administration is conducting a rulemaking on safety issues.[134] No mention is made of whether this rulemaking has concluded. Rather, EPA states in a conclusory fashion that state and federal pipeline safety standards "ensure that captured CO_2 will be securely conveyed to a sequestration site."[135]

In addition, as discussed above, there is only one coal-fired steam generating unit that comes close to meeting a 90 percent capture rate, and that unit has been plagued with issues and does not reliably meet that capture rate. And there are no gas-fired combustion turbines employing CCS at all.

For all these reasons, EPA's determination that CCS with a 90 percent capture rate is achievable across the nation as a whole is arbitrary, capricious, and unlawful.

---

[132] Congressional Research Service, Carbon Dioxide Pipelines: Safety Issues at 1 (June 3, 2022), https://crsreports.congress.gov/product/pdf/IN/IN11944.

[133] *Id.*

[134] 88 Fed. Reg. at 33,294.

[135] *Id.*

3. CCS Has Many Obstacles that Prevent it From Being Considered as a "Best" System to Reduce GHG Emissions from Fossil Fuel-Fired EGUs.

CCS cannot be considered the BSER for fossil fuel-fired EGUs because CCS "give[s] a competitive advantage to one State over another"[136] due to the lack of geological storage across the nation, the fact that CCS is a water intensive technology that has a large parasitic load, and the fact that it imposes unreasonable costs at the level of individual plants.[137]

a. Geographic and Site Limitations

CCS technology is distinct from other emission controls in that its application requires that suitable geological formations for underground storage of captured CO_2, such as deep saline reservoirs, or CO_2 transport pipelines be available nearby. The reality is, however, that many parts of the country have no assessed capacity for CO_2 storage, and even those that do may not be adequate for large-scale CO_2 sequestration when examined on a site-by-site basis.

As shown by DOE and USGS surveys, potential repository sites are not evenly distributed throughout the United States, and many locations throughout the country lack suitable geological conditions for carbon storage.[138] The USGS National Assessment concludes that fully two-thirds of the technically accessible storage resources in the United States are confined to the Coastal Plains region, with 91 percent of that total limited to a single basin.[139] Another tenth of the nation's

[136] *Sierra Club*, 657 F.2d at 325.

[137] *Id.* at 330.

[138] *See* U.S. Department of Energy, National Energy Technology Laboratory, *Carbon Storage Atlas and Data Resources*, https://netl.doe.gov/carbon-management/carbon-storage/atlas-data ("NETL Carbon Storage Atlas"); U.S. Department of the Interior, U.S. Geological Survey, Circular 1386, Version 1.1, *National Assessment of Geologic Carbon Dioxide Storage Resources—Results* (Sept. 2013), https://pubs.usgs.gov/circ/1386/pdf/circular1386_508.pdf ("USGS National Assessment").

[139] USGS National Assessment at 3 (Fig. 1), 15.

potential storage capacity is in Alaska, almost all of which is confined to the remote North Slope.[140] In contrast, the entire Eastern Mesozoic Rift Basin region, which includes several major metropolitan areas along the Eastern seaboard, contains less than 1 percent of the nation's storage capacity.[141]

Moreover, the CO_2 storage at any specific site will not be known until the site is assessed for specific criteria. As DOE noted in the first edition of its North American Carbon Storage Atlas, "[i]t is important that a regionally extensive confining zone (often referred to as caprock) overlies the porous rock layer and that no major faults exist."[142] The North American Carbon Storage Atlas also cites the importance of documenting the CO_2 storage capacity, the "injectivity," and the ability of the porous rock to permanently trap CO_2. All of these criteria are necessary to evaluate the storage potential of a site.[143] Other site-specific items that need to be considered include land-management, regulatory restrictions, and whether the basin contains freshwater that would restrict its use for CO_2 storage.[144]

Furthermore, the estimates presented in the DOE and USGS reports are uncertain, "high level" assessments of potential storage resources, and actual storage capacity is likely to be significantly lower than the estimates presented in these studies. USGS researchers have expressed concern that due to issues such as reservoir pressure limitations, boundaries on migration of CO_2, and acceptable injection rates over time, "it is likely that only a fraction" of the high-level estimated

---

[140] *Id.*

[141] *Id.* at 3 (Fig 1).

[142] *The North American Carbon Storage Atlas – 2012* (First Edition), Slide 18, https://www.slideshare.net/dove000/nacsa2012webversion-43472232 ("North American Carbon Storage Atlas").

[143] *Id.*

[144] USGS National Assessment at 15.

technically accessible CO_2 storage resources could be available.[145] A formation may have one or more fractures in the caprock or may have well penetrations. A site may have sufficient porosity but low permeability. Current information in most cases would not be sufficient to show whether CO_2 is likely to settle in a broad or narrow depth range, a question that is important to determine how the CO_2 plume will spread and to address displacement of underground fluids. Settlement of CO_2 and displacement of underground fluids factor into the property rights that must be pre-arranged for sequestration. These critical issues require costly, potentially time-consuming research and resolution that takes several years; it can take several years simply to evaluate a site for CO_2 storage potential. If the site proves to be unsuitable for storage after a company has invested years of effort and millions of dollars into the evaluation, the company may have to begin the process all over again with additional time and money.

For example, in the late 2000s, several entities (including PGen members) participated in a CO_2 storage pilot project to investigate the suitability of a formation in the Colorado Plateau region of northeastern Arizona.[146] Five candidate project sites were evaluated prior to the selection of a final test site near Holbrook, Arizona. The project participants held meetings to inform the local community about the project beginning in 2007, obtained the necessary state and federal permits for well drilling and CO_2 injection in 2008-2009, and completed the 3,800 foot well in 2009. After investing over $5.7 million and several years on the project, the participants found that the

[145] *See* Steven T. Anderson, *Cost Implications of Uncertainty in CO_2 Storage Resource Estimates: A Review*, 26:2 NATIONAL RESOURCES RESEARCH 137-59 (Apr. 2017), https://link.springer.com/article/10.1007/s11053-016-9310-7; Steven T. Anderson, *Risk, Liability, and Economic Issues with Long-Term CO_2 Storage—A Review*, 26:1 Natural Resources Research 89-112 (Jan. 2017), https://link.springer.com/article/10.1007/s11053-016-9303-6.

[146] DOE provided 80.5 percent of the overall funding for this project. *See* West Coast Regional Carbon Sequestration Partnership ("WESTCARB"), *Factsheet for Partnership Field Validation Test (Rev. 10-28-09)* at 5, http://www.westcarb.org/pdfs/FACTSHEET_AZPilot.pdf.

geological formation had insufficient permeability to proceed with CO_2 injection, and the project was discontinued.[147]

Suitable sites for EOR are similarly limited and uncertain. EOR sites are unevenly distributed across the country. DOE estimates that overall EOR capacity for captured CO_2 is only about 10 percent of the capacity estimated for deep saline sequestration.[148] Moreover, as with sequestration, several years of subsurface feature characterization may be required before a site can be assessed as suitable for EOR. These limits are particularly significant because the only commercial utility applications of CCS to date that could be cost-justified have had to rely on EOR. The reliance on EOR, however, renders the operation volatile—as can be seen from the Petra Nova project in Texas, which ceased operations because of an economic downturn at the beginning of the COVID-19 pandemic.[149]

In addition, the lack of availability of the needed geographic criteria cannot be easily solved by the construction of pipelines to move the separated gas to areas of the country that can store the CO_2. There are many hurdles to pipeline construction. First, it is extremely expensive; current pipeline projects have cost between $4 to10 million per mile of pipe. Second, pipeline projects face

[147] *See* WESTCARB, "Arizona Utilities CO_2 Storage Pilot—Cholla Site," http://www.westcarb.org/AZ_pilot_cholla.html.

[148] North American Carbon Storage Atlas at 25 (estimating that 250 billion tons of CO_2 can be used for EOR and thus stored, which is about 10 percent of the capacity estimated for deep saline sequestration).

[149] *See* NRG, Coal: Examining how we use Earth's oldest resource, https://www.nrg.com/generation/coal.html (noting that the plant "has been impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil" and that "[g]iven the state of oil markets, in May 2020 the carbon capture facility was placed in reserve shutdown status to allow it to be brought back online when economic conditions improve").

significant opposition from the public and require extensive permitting that is not easily or quickly obtained.[150]

Finally, even if there is a way to store the separated CO_2 (either onsite or by pipeline to a suitable site), CCS may not be able to be installed on an existing EGU because of space constraints at the plant. A carbon capture facility is big and requires a very large amount of land to be available for its construction. Many existing EGUs do not have the land available at the plant to construct the carbon capture facility, particularly in urban areas.

b. Water Constraints

It is well recognized that CCS requires significant water for process operation. As EPA has acknowledged, "[a]ll CCS systems that are currently available require substantial amounts of water to operate," which "limit[s] the geographic availability of potential future CCS construction to areas of the country with sufficient water resources."[151] Like sequestration, water resources for use in CCS are severely limited in some parts of the country.

EPA acknowledges that CCS increases water consumption at an EGU. For coal-fired steam generating units, EPA estimates an increase in water consumption of 36 percent gross.[152] EPA glosses over this fact and notes that a feasibility study for a project by SaskPower "would rely entirely on water condensed from the flue gas and thus would not require any increase in external water consumption." Citation to a *feasibility study* that plans on trying something for the first time does not solve the present problem. Neither is the problem solved by using "dry or hybrid cooling systems" in "[r]egions with limited water supply," as EPA suggests, while simultaneously

[150] Any flexibilities that can be provided through the National Environmental Policy Act process to expedite permitting of projects would be useful for compliance with EPA's GHG reduction programs under section 111.

[151] 83 Fed. Reg. 65,424, 65,443 (Dec. 20, 2018); *see also generally id.* at 65,442-44.

[152] 88 Fed. Reg. at 33,350.

acknowledging that "wet cooling systems [are] more effective."[153] EPA then without anything more concludes that it "is proposing that the water use … requirements are manageable and therefore the EPA does not expect any of these considerations to preclude coal-fired power plants generally from being able to install and operate CCS."[154] Acknowledging a problem exists, pointing to a feasibility study for new technology not yet in operation, and noting possible alternatives that are not as effective do not form the basis for a conclusion that the problem is manageable. EPA's conclusion is arbitrary and capricious, and therefore unlawful.

EPA fares no better with regard to water issues resulting from CCS use at gas-fired combustion turbines. There, EPA acknowledges that CCS use at a combined cycle combustion turbine results in "an increase of about 50 percent" in water use.[155] Yet, EPA concludes that "because NGCC units require limited amounts of cooling water, the absolute amount of increase in cooling water required due to use of CCS does not present unsurmountable concerns."[156] EPA also notes that "many NGCC units currently use dry cooling technologies and the use of dry or hybrid cooling technologies for the CO_2 capture process would reduce the need for additional cooling water."[157] There is no analysis beyond this. For example, there is no discussion of whether CCS can use dry cooling technologies, whether they have been used at NGCC units with CCS (which would be impossible since CCS has never been employed at an NGCC), or how effective those technologies might be. Nor is there any analysis of how a 50 percent increase in water use affects

[153] *Id.*

[154] *Id.*

[155] *Id.* at 33,302.

[156] *Id.*

[157] *Id.*

arid areas of the country. More analysis is required to support EPA's conclusion. As proposed, EPA's conclusion is unsupported, arbitrary, and capricious.

The D.C. Circuit has previously found that "an efficient water intensive technology … might be 'best' in the East where water is plentiful, but environmentally disastrous in the water-scarce West."[158] Therefore, the court concluded that a water intensive technology could not be selected as the BSER under section 111 because it would have the effect of precluding construction of new sources in states that lack the resources necessary (here, water) to allow compliance with the standard at a reasonable cost.[159] EPA has not explained why the court's reasoning in that case does not apply here. EPA's conclusory proposed findings that water will not be a barrier to the deployment of CCS at coal-fired steam generating units and at NGCC combustion turbines violate section 111.

c. Parasitic Load

There is a significant parasitic load associated with the operation of CCS equipment. EPA estimates the operation of CCS equipment at a new 500 MW NGCC EGU will de-rate the plant by 11 percent to a 444 MW plant.[160] For coal-fired steam generating units, EPA estimates that the CCS equipment would reduce the output at a 474 MW-net (501 MW-gross) coal-fired steam generating unit by 23 percent to a 425 MW-net unit.[161] For NGCC units, EPA recommends that a developer simply build a larger NGCC plant to compensate for the parasitic load and proposes to find that "[a]lthough the use of CCS imposes additional energy demands on the affected units, those units are

[158] *Sierra Club*, 657 F.2d at 330.

[159] *Id.*

[160] 88 Fed. Reg. at 33,302.

[161] *Id.* at 33,349.

able to accommodate those demands by scaling larger, as needed."[162] This recommendation and conclusion fails to consider the effect of CCS on existing large, frequently used NGCCs. EPA's failure to examine the effect of the energy penalty from CCS on those existing units is arbitrary and capricious.

EPA does not make any recommendation for existing coal-fired steam generating units; for those units, EPA simply proposes to find "that the energy penalty is relatively minor compared to the GHG benefits of CCS and, therefore, does not disqualify CCS as being considered the BSER for existing coal-fired steam generating units."[163] EPA's analysis misses the mark. The parasitic load associated with CCS is not minor: it amounts to 25 to 30 percent.[164] As discussed above in Section III, the energy transition has resulted in the electricity grid in the United States becoming strained, with reliability being increasingly threatened. Installing CCS on existing fossil fuel-fired EGUs will exacerbate this reliability problem because a large percentage of the energy being generated will now be needed to power the CCS technology at power plants rather than being available to the consumer. EPA needs to consider the effect of CCS on electric reliability, which it has not done.[165] Failure "to consider [this] important aspect of the problem" is arbitrary and capricious.[166]

---

[162] *Id.* at 33,302.

[163] *Id.* at 33,349.

[164] D. Walsh, Analysis of EPA's Proposed Construction Timeframes for CCS Projects at 4 (Aug. 3, 2023) ("Walsh Report") (Attachment G to these comments).

[165] *Id.* ("EPA has failed to address the resource adequacy challenges that will occur when fossil generation sites accept a 25%-30% parasitic load loss to run an associated CCS site."). The alternative of "add[ing] onsite generation to run the CCS plant" does not solve the problem. This just triggers "[New Source Review] and additional air permitting requirements that are federal, state, and local based may add an additional 24-36 months prior to commencing construction" and would also be costly. *Id.*

[166] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

d. Cost

CCS is an expensive technology, particularly for existing plants. EPA underestimates the cost of CCS and overestimates the impact of the IRA, thus severely distorting the cost impact of this technology.[167] EPA in its cost estimates relies heavily on the costing methodology developed by the National Energy Technology Laboratory (NETL), but it ignores the limitations of this methodology.[168] In short, the NETL methodology is appropriate for comparing alternatives, but it does not seek to estimate the full cost of a project. Indeed, comparing NETL methodology to the "full cost" methodology employed by the EIA (and executed by a company that often works EPA, including in this rulemaking, Sargent & Lundy) yields a difference of 168 percent (i.e., for a 650 MW supercritical unit, the NETL estimate is $3,482/kw whereas the Sargent & Lundy EIA estimate is $5,876/kw).[169]

Congress recently made numerous changes to Section 45Q of the Internal Revenue Code in the IRA that have the effect of increasing the tax credits available for carbon sequestration. Under the IRA, projects that are placed in service after December 31, 2022, may receive a credit of $85 per ton for CO_2 disposed of in secure geologic storage and $60 per ton of CO_2 used for EOR and disposed of in secure geologic storage or utilized in a qualified manner.[170] This is a significant increase from the amounts previously available for units placed in service before 2023.

---

[167] EPA should consider analyzing the cost of CCS (and hydrogen co-firing) without the IRA. The presence of the IRA in EPA's current analysis masks the costs that would occur if IRA support fails to materialize.

[168] D. Campbell, Analysis of the National Energy Technology Laboratory Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy at 2 (Aug. 3, 2023) ("Campbell NETL Cost Report") (Attachment H to these comments).

[169] *Id.* at 9.

[170] Pub. L. No. 117-169, § 13104(c).

While these additional tax credits should help mitigate the cost issue, there remains significant risk associated with CCS construction. The Section 45Q tax credits available through the IRA may be taken *only* if the facility is able to capture a minimum amount of CO_2. An electric generating facility must capture at least 18,750 tons of CO_2 per year and have a capture design capacity that is at least 75 percent of the unit's baseline carbon oxide production.[171] Because of the current nascent state of the technology, there is risk that the technology may not work, and if that occurs, then the EGU will not be eligible to receive the tax credits that help offset some of the significant costs.

Moreover, as Dr. William Morris explains, "the assumption that the credit is directly paid and instantaneous shows that the EPA misunderstands (or misrepresents) basic tax law or financial modeling."[172] Indeed, the flaws in EPA's consideration of cost for CCS systems are many:

> The EPA has not sufficiently modeled the cost of CCS implementation, nor has the EPA sufficiently modeled the impacts of adding CCS to the existing fleet in terms of grid impacts, cycling capabilities to meet the needs of an increasing renewable energy penetration grid, water use and impacts, and technological readiness.
>
> The EPA should perform an adequate analysis to determine how the technology required will impact the operation of the grid, and what it will cost in a variety of regions throughout the country, all of which will be significantly impacted by this regulation.
>
> Instead, the EPA has used fundamentally flawed models which do not use consistent baseline assumptions. Their assumptions use conflicting costs for CO_2 transportation, storage, and monitoring. The assumptions use capacity factors that are not reflected in the actual capacity factor data from the EIA, extrapolate the least cost construction environments to the entire United States without any acknowledgment of how location substantially impacts costs, completely misrepresent the impact of the 45Q tax credit in financial modeling, and provide conflicting examples of BSER projects, which

[171] *Id.* § 13104(a).

[172] Morris CCS Report at 8.

would likely not even comply with the proposed rule as justification for the rule.[173]

C. Hydrogen Co-Firing at Natural Gas-Fired Combustion Turbines Does Not Meet the Requirements of Section 111 of the CAA and Impermissibly "Redefines" the Source.

Hydrogen combustion is another promising technology that is not yet ready to be deployed throughout the industry as a system of emission reduction. There are many hurdles that need to be overcome before that can be the case, including EGUs being able to combust large amounts of hydrogen for extended periods of time, a ready-supply of hydrogen, an ability to transport the hydrogen, and an ability to store the hydrogen. As discussed further below, none of these hurdles have yet been overcome, and EPA's wishful thinking that all of these things will fall into place by 2032 are "wispy hopes based on no evidence at all."[174]

EPA proposes that one of the BSER options for new and existing combustion turbines in certain subcategories is the co-firing of low-GHG hydrogen, first at a level of 30 percent beginning in 2032 and second at a level of 96 percent beginning in 2038.[175] As an initial matter, the very fact that EPA phases the proposed standards for hydrogen co-firing over 15 years, with one BSER level that would apply in eight years and the second in fifteen years, demonstrates that at least the latter is not adequately demonstrated and is certainly not achievable at this time. (In fact, it would not even be achievable in 2032, by EPA's own admission.) Indeed, neither BSER levels (30 percent or 96 percent) is adequately demonstrated or achievable. EPA's determination that hydrogen co-firing is a BSER option for new NGCC units and for existing large and frequently used NGCC units is incorrect and violates section 111 of the CAA. In addition, co-firing hydrogen improperly

[173] *Id.* at 10.

[174] *NRDC v. Thomas*, 805 F.2d at 432.

[175] 88 Fed. Reg. at 33,325 (Tables 3 and 4), 33,363-66.

"redefines" the source, in violation of the CAA. For the reasons outlined below, EPA should not finalize its proposal for hydrogen co-firing.

1. The Ability of Combustion Turbines to Combust Hydrogen at the Levels Contemplated by EPA and Over an Extended Period of Time Is Not Adequately Demonstrated.

The ability of combustion turbines to co-fire hydrogen at either the 30 percent or the 96 percent levels over an extended period of time is not adequately demonstrated. As EPA acknowledges, "utility combustion turbines have only recently begun to co-fire smaller amounts of hydrogen as a fuel to generate electricity" and "[t]he industrial combustion turbines currently burning hydrogen are smaller than the larger utility combustion turbines…."[176]

At this time, the most hydrogen that an NGCC has been able to combust is 44 percent—and most units are much lower than that.[177] There are also significant increases in NOx emissions associated with hydrogen combustion (increases of approximately 24 percent) that offset some of the benefits of reduced CO_2 emissions.[178] EPA's response to these issues is to point to the fact that "the major combustion turbine manufacturers *are designing* combustion turbines that will be capable of combusting 100 percent hydrogen by 2030" and to state that these "*goals* of equipment manufacturers," combined with the ability of existing combustion turbines to combust hydrogen at lower levels than proposed supports a determination that the technology to combust 30 percent

[176] *Id.* at 33,311.

[177] Utility Dive, *NYPA burns up to 44% green hydrogen in GE turbine in first such retrofit of a US natural gas plant* (Sept. 23, 2022), https://www.utilitydive.com/news/new-york-power-authority-burns-green-hydrogen-cuts-emissions-EPRI-GE-Airgas-NYPA/632527/.

[178] Clean Energy Group, *Hydrogen Hype in the Air* (Dec. 14, 2020), https://www.cleanegroup.org/hydrogen-hype-in-the-air/ (noting two European studies that have found that combusting "hydrogen-enriched natural gas in an industrial setting can lead to NOx emissions up to *six times that of methane*" (emphasis in original)); *see also* Kiewit Engineering Group, Inc., Technical Comments on Hydrogen and Ammonia Firing § 2.4, at 18 (Aug. 4, 2023) ("Kiewit Report") (Attachment I to these comments); Hydrogen Cofiring Demonstration at 2-3.

hydrogen by 2032 and 96 percent hydrogen by 2038 is adequately demonstrated.[179] However, Kiewit Engineering Group ("Kiewit"), one of the largest construction companies and engineering organizations in North America—indeed, one that is involved in current hydrogen projects—calls the manufacturers' goals of achieving 100 percent hydrogen firing by 2030 "aspirations."[180] Kiewit notes there are "major obstacles to overcome before those aspirations could be realized," including making the turbines larger or using higher pressures, resolving issues related to higher flame temperature and increased flame speed, addressing increased NOx emissions, and additional difficulties related to retrofitting existing combustion turbines.[181]

Section 111 requires more than a "crystal ball inquiry,"[182] and EPA has not met the necessary legal standard to find hydrogen co-firing at these levels adequately demonstrated. Courts have required that a technology must be shown to be reasonably reliable.[183] There must be an operational history that shows more than mere technical feasibility and manufacturer "aspirations"; the

[179] 88 Fed. Reg. at 33,312 (emphasis added).

[180] Kiewit Report at 14. Another expert notes that EPA references mere "marketing materials" related to hydrogen co-firing from major manufacturers such as GE, Siemens, and Mitsubishi. D. Campbell, Hydrogen in Combustion Turbine Electric Generating Units, at 4 (Aug. 3, 2023) ("Campbell Hydrogen Report") (Attachment J to these comments); *see also id.* at 6 ("Although there is a lot of marketing or forecast development of machines that will run at 30% blends, they are neither demonstrated nor commercially available with guaranteed performance today to be a viable option to meet the EPA requirements.").

[181] Kiewit Report at 14-15 (citing Department of Energy National Energy Technology Laboratory's (DOE/NETL) white paper, "A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOx Control). Kiewit further notes that only relatively small, aeroderivative combustion turbines are currently able to burn higher percentage of hydrogen, but these types of turbines are used as peaking units and therefore would not be subject to the proposed standards. *Id.* at 15.

[182] *Portland Cement Ass'n*, 486 F.2d at 391.

[183] *Essex Chem. Corp.*, 486 F.2d at 433; *NRDC v. Thomas*, 805 F.2d at 428 n.30.

technology must be dependable and effective and based on actual operating experience within the source category or at sufficiently similar sources. This operational history is absent here.[184]

In addition, as EPA acknowledges, increased NOx emissions result from hydrogen combustion, at least at hydrogen blends of 70 percent or greater. But as Kiewit explains, "there is not significant testing data available to show that NOx emissions will not be a problem," even when co-firing 30 percent hydrogen, especially for existing units that are retrofit.[185] The technology of dry low NOx ("DLN") combustion is being developed to combat NOx emissions, but as EPA notes it "is currently more limited."[186] EPA says that developers "are designing combustion turbines … with DLN designs that assure acceptable levels of NOx emissions."[187] These "designs" are not yet final and are unproven.[188] EPA then notes that selective catalytic reduction ("SCR") can be used to further reduce NOx emissions.[189] But EPA does not do any analysis of the cost associated with SCR installation (which is very expensive). EPA needs to analyze the important environmental effect of increased NOx emissions, as well as its increased cost, more thoroughly.

---

[184] One expert reviewed available data for hydrogen co-firing demonstrations and concluded "these very limited and short-duration hydrogen co-firing demonstrations do not provide justification to qualify as being adequately demonstrated today and much work would be required to meet a 2032 goal on a commercial basis." Campbell Hydrogen Report at 5.

[185] Kiewit Report at 18.

[186] 88 Fed. Reg. at 33,312.

[187] *Id.*

[188] "[W]hile the [original equipment manufacturers ("OEMs")] are working to produce dry low NOx (DLN) hydrogen combustors that can maintain lower NOx emissions in the future, it is uncertain whether they will be successful at maintaining the levels that are currently achievable. As with the 30% hydrogen firing case, the OEMs' ability to keep NOx low is most limited for the combustion turbines that are retrofitted to fire hydrogen." Kiewit Report at 18.

[189] 88 Fed. Reg. at 33,312.

2. The Supply of Low-GHG Hydrogen Needed to Implement the Proposed Rules Does Not Exist.

The current supply of low-GHG hydrogen is practically non-existent.[190] As EPA acknowledges, "[o]nly small-scale facilities are currently producing [low-GHG] hydrogen through electrolysis with renewable or nuclear energy."[191] Larger facilities are "under development" and "anticipated to significantly increase the availability of low-GHG hydrogen by 2032."[192]

EPA believes that the IRA and the Infrastructure Investment and Jobs Act will result in an ample supply of low-GHG hydrogen. EPA notes that 374 new projects were announced by August 2022 "that would produce 2.2 metatons (Mt) of low-GHG hydrogen annually," which is a 21 percent increase from current levels.[193] First, there is no guarantee that these projects will proceed or be successful. Second, if the current levels, by EPA's own admission are very small, a 21 percent increase from those levels will not amount to much. There is no analysis by EPA of how much low-GHG hydrogen will be needed by 2032 and 2038 and how much of that need will be met by these projects. EPA needs to assess how much low-GHG hydrogen will be needed for this program. Pointing to projects in the absence of those data is meaningless.[194]

---

[190] *See* Congressional Research Service, *Hydrogen in Electricity's Future* at 11 (June 30, 2020), https://crsreports.congress.gov/product/pdf/R/R46436 (noting high cost of producing hydrogen).

[191] 88 Fed. Reg. at 33,312.

[192] *Id.*

[193] *Id.*

[194] *See also* Kiewit Report § 3.1 at 19 (explaining that the "timeline [for hydrogen hubs supported by DOE funding] is vastly out of step with the timeline for the GHG rule that the EPA has established"). The Kiewit Report also discusses the daunting task and constraints (e.g., strain on the supply chain for precious metals) faced by the electrolyzer (which is needed for electrolysis—the process needed for producing low-GHG hydrogen) OEMs to increase production enough to meet the demand for hydrogen under the proposed BSER. *Id.* § 4 at 22-24. EPA has not analyzed these issues either.

EPA also fails to address the practical difficulties associated with producing low-GHG hydrogen. Looking at three natural gas-fired plants in Michigan owned by Consumers Energy illustrates the scope of the problem. At the Zeeland Generating Station (an NGCC located in Zeeland, Michigan), a 684 MW solar array would be needed to produce enough low-GHG hydrogen for co-firing at a 30 percent level at that plant. A solar array this large would occupy approximately 7.5 square miles. If that same plant were to co-fire hydrogen at a 96 percent blend, this would require about 4,787 MW of solar generation to produce enough low-GHG hydrogen for the plant. A solar array this large would occupy about 52.4 square miles. The figures are similar for the Jackson Generating Station (an NGCC located in Jackson, Michigan). These figures would approximately double for the Covert Generating Station (a gas-fired EGU in Covert, Michigan). In total, Consumers Energy would need about 19,000 MW of solar energy, covering about 200 square miles to produce the low-GHG hydrogen needed to power these three gas-fired EGUs. These figures are almost 2.5 times the entire solar build that Consumers Energy contemplates over the next twenty years. Importantly, this is only *three* of the gas-fired EGUs that are affected by the Proposed Rules. These figures are exponentially higher when one looks at the fleet of affected gas-fired EGUs as a whole.

Until these concerns about the integrity of the fuel supply and whether there can even be a consistent source of hydrogen are resolved, the Proposed Rules are premature and are not achievable (as required by section 111). The vast majority of hydrogen today is made from natural gas and is very carbon-intense,[195] which EPA correctly notes will not achieve GHG emission reductions. Implementing a hydrogen-based standard makes no sense until there is a strong and

[195] DOE, Office of Energy Efficiency & Renewable Energy, *Hydrogen Production: Natural Gas Reforming*, https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming ("Today, 95% of the hydrogen produced in the United States is made by natural gas reforming in large central plants").

reliable supply of low-GHG hydrogen, which simply does not exist at this time. Because of the lack of supply of low-GHG hydrogen, EPA's proposed BSER is not achievable, and thus not in accordance with section 111.

3. Even if There Were an Ample Supply of Low-GHG Hydrogen to Implement the Proposed Rules, The Infrastructure Needed to Transport and Store the Hydrogen Does Not Exist.

Even assuming that there could be an ample supply of low-GHG hydrogen by 2032 and 2038 to fulfill the requirements of the Proposed Rules, the infrastructure to support transporting and storing the hydrogen is completely lacking at this time.

Some of the issues associated with CCS are also present with hydrogen combustion. For example, as with CCS, there needs to be a means to physically store the hydrogen.[196] Hydrogen can be stored in salt caverns, depleted oil and gas reservoirs, aquifers, abandoned mines, or rock caverns, but these features need to be close to the EGU—which is not always possible. While hydrogen can be stored in pressure vessels, this requires proper materials to avoid embrittlement. It would also require vast acreage,[197] and has safety and fire protection implications. In addition, like CCS, water is a significant issue. Producing enough hydrogen for a natural-gas plant requires enormous amounts of water, which is not available in large parts of the country.[198]

---

[196] *See, e.g.*, DOE, NETL, *Underground Hydrogen Storage Remains a Key Research Topic for NETL* (Aug. 22, 2022), https://netl.doe.gov/node/11982.

[197] *See* Kiewit Report § 2.3 at 16-17 ("5 days of storage … for the H-Class turbine … would be approximately 17 acres of storage tanks.").

[198] D. Pimentel, et al., *Renewable Energy: Current and Potential Issues: Renewable energy technologies could, if developed and implemented, provide nearly 50% of US energy needs; this would require about 17% of US land resources* at 1115, BioScience, Vol. 52, No. 12 (Dec. 2002), https://academic.oup.com/bioscience/article/52/12/1111/223002 (noting "[t]he water required for electrolytic production of 1 billion kWh per year of hydrogen is approximately 300 million liters of water per year," amounting to 3000 liters of water per year on a per capita basis, and noting that "[w]ater for the production of hydrogen may be a problem in arid regions of the United States and the world"); *see also* Campbell Hydrogen Report at 4 ("EPA also notes … that 'for each kg of hydrogen produced through electrolysis, 9 kg of by-product oxygen are also produced and 9 kg of purified water are consumed.' To create enough fuel to run a single LM 6000 at 46.6 MW gross on

A standard of performance under section 111 must be achievable "for the industry as a whole."[199] EPA has not done any analysis of the important issues associated with storing hydrogen, nor has it analyzed the important issue of the amount of water needed to produce hydrogen. This is again a failure to address a critical part of the problem and is arbitrary and capricious as a result.[200]

The pipeline network for hydrogen in the United States is in its infancy and consists of 1,600 miles of pipelines.[201] In contrast, the pipeline network for natural gas covers over 300,000 miles.[202] For EGUs not immediately near a low-GHG hydrogen generating facility, the construction of a pipeline to transport the low-GHG hydrogen is necessary in order for the performance standard to be achievable. But, as discussed above, the cost to construct a pipeline is very high and permitting is a years-long process. While more established pipelines (such as for natural gas) are met with increasing resistance, this may be elevated for hydrogen, which is even more explosive.[203] This may

100% hydrogen, one would use 173,142 US gallons of water per day just to make hydrogen. Any additional water requirements to run the unit would be added to this. In many regions of North America, water resources are at a premium now and would not be able to support these levels of low-GHG hydrogen production, so this provides another challenge to the hydrogen supply.").

[199] *National Lime*, 627 F.2d at 431.

[200] *State Farm*, 463 U.S. at 43.

[201] 88 Fed. Reg. at 33,313.

[202] Congressional Research Service: Pipeline Transportation of Hydrogen: Regulation, Research, and Policy at 5 (Mar. 2, 2021), https://crsreports.congress.gov/product/pdf/R/R46700. Using the existing natural gas pipeline infrastructure to deliver hydrogen to combustion turbines would not achieve the proposed BSER requirements. *See* Campbell Hydrogen Report at 6 ("Although there is much talk about blending hydrogen into the natural gas transmission and distribution system, an amount of between 1% and 5% is likely all that is practical without major changes to end use equipment. This does not meet a 30% blend target in 2032.").

[203] *See* Kiewit Report at 21 ("Much of [the new hydrogen] pipeline will need to be routed in highly populated areas. Given the safety concerns discussed in Section 3.2, the issue of supply pipelines is a significant barrier to the practicality of the hydrogen requirements of the proposed rule.").

make permitting even more difficult. The Agency also completely ignores safety issues for hydrogen pipelines and fails to do any analysis of this critical issue.[204]

EPA's response to this achievability problem is to note that "[t]he majority of announced combustion turbine EGU projects proposing co-firing hydrogen are located close to the source of hydrogen. Therefore, fuel delivery systems (i.e., pipes) … can be designed to transport hydrogen without additional costs."[205] All but one of the announced projects that EPA cites, several of which are Kiewit projects, are not yet in operation. Kiewit notes that the facility that is in operation "can only fire hydrogen for 45 minutes before it runs out of storage."[206] Moreover, "none of these units are expected to fire anywhere close to 96% hydrogen initially. Instead, they expect to burn between 30-50% hydrogen, with an aspirational goal of having the capability of firing more."[207] Kiewit continues: "the timeline for most of these projects to be firing 100% hydrogen is 2045. This is significant since these units are the *early adopters*, with high aspirations for firing hydrogen. The 2045 date of these units, which the EPA presents as examples of what is possible with hydrogen firing, cannot support EPA's 2038 deadline for 96% hydrogen firing."[208]

Even if EPA's claims that most EGU projects proposing to co-fire hydrogen will be located near hydrogen sources were true and relevant, while the construction near the source of the low-GHG hydrogen might be conceivable for new EGUs, it "give[s] a competitive advantage to one State over another in attracting industry," in violation of section 111.[209] And this solution is

---

[204] *See id.* at 20 (discussing safety issues for hydrogen pipelines and noting "EPA's discussion of pipelines does not address the significant challenges of this transport piping at all").

[205] 88 Fed. Reg. at 33,314.

[206] Kiewit Report at 11.

[207] *Id.*

[208] *Id.*

[209] *Sierra Club*, 657 F.2d at 325.

completely unworkable for existing EGUs, unless the owner or operator wants to prematurely retire an EGU and construct a new one near a low-GHG hydrogen source. As with geologic storage issues with regard to CCS, this leads to a state that does not have a low-GHG facility being harmed twice (once when a plant in its borders closes and again when the new construction takes place in another state).

EPA also seems to suggest that trucking hydrogen is a cost-effective option up to 200 miles.[210] Even a small combustion turbine would require so many trucks to keep it running that the "logistics of moving this many trucks would be unmanageable."[211] Even "[w]ith the trucks being unloaded 12 hours per day, it would take between 12 and 24 days to unload the number of trucks for a single F-Class turbine to provide 1 day of hydrogen storage. It would take between 17 and 35 days of truck deliveries for a single H-Class turbine and 1 day of storage."[212]

EPA has failed to consider myriad issues relating to the transportation and storage of hydrogen. As such, its proposal for hydrogen co-firing to be the BSER for certain subcategories of combustion turbines is arbitrary, capricious, and otherwise not in accordance with the CAA.

4. EPA's Proposed BSER for Hydrogen Co-Firing Impermissibly Redefines the Source.

EPA notes in the Proposed Rules that the Supreme Court in *West Virginia v. EPA* noted "with approval … that 'fuel-switching' was one of the 'more traditional air pollution control measures.'"[213] The traditional types of fuel-switching that were being referenced there were not a change from one fuel type to an entirely different one. Rather, it reflects measures such as switching

[210] EPA, Office of Air and Radiation, Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document at 28 (May 23, 2023); *see also* 88 Fed. Reg. at 33,309.

[211] Campbell Hydrogen Report at 5.

[212] Kiewit Report at 17.

[213] 88 Fed. Reg. at 33,315 (quoting *West Virginia v. EPA*,142 S. Ct. 2587, 2615 (2022)).

from high-sulfur coal to lower-sulfur coal. That is not the case here. Here, EPA proposes to replace natural gas (one type of fuel) with hydrogen (a completely different type of fuel).

EPA also apparently failed to read footnote three in the Supreme Court's opinion. There, the Court noted that the dissenting opinion suggested that EPA could require coal-fired plants to become natural gas-fired plants to reach the same environmental result. But the Court said that "EPA has never ordered anything remotely like that, and we doubt it could."[214] Yet, this is exactly what EPA is attempting to do here. By 2032, a natural gas-fired combustion turbine must become a hybrid plant that burns large quantities of both natural gas and hydrogen. And by 2038, a natural gas-fired combustion turbine is required to "co-fire" 96 percent hydrogen. Any combustion turbine that combusts 96 percent hydrogen is a hydrogen-fired combustion turbine; it is no longer a gas-fired turbine.

EPA cannot force a natural gas-fired turbine to no longer burn natural gas. This is considered "redefining the source," which is not permissible under the CAA.[215] EPA must withdraw hydrogen co-firing as a BSER option for new and existing combustion turbines.

D. Co-Firing with Natural Gas at Coal-Fired EGUs Does Not Meet the Requirements of Section 111 and Impermissibly Redefines the Source.

EPA is proposing that the BSER for medium-term existing coal-fired steam generating units (i.e., those units that will operate after January 1, 2035, but retire before January 1, 2040) is natural

[214] *West Virginia v. EPA*, 142 S. Ct. at 2612 n.3

[215] *See, e.g.*, *West Virginia v. EPA*, 142 S. Ct. at 2612 n.3 (expressing "doubt" EPA could "requir[e] coal plants to become natural gas plants"); *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2448 (2014) (finding that Best Available Control Technology, which is intertwined with section 111, "cannot be used to order a fundamental redesign of the facility"); *In re Prairie State Generating Co.*, 13 E.A.B. at 25 (holding that it is "long-standing EPA policy that certain fuel choices are integral to the electric power generating station's basic design"); *Sierra Club v. EPA*, 499 F.3d 653, 655-56 (7th Cir. 2007) (recognizing the choice of fuels is an essential part of a source's purpose and design, and requiring a source to change its design to combust an alternative fuel constitutes redefining the source).

gas co-firing at 40 percent.[216] EPA says it "believes that because a large supply of natural gas is available, devoting part of this supply for fuel for a coal-fired steam generating in place of the coal burned at the unit is an appropriate use of natural gas and will not adversely impact the energy system…."[217] EPA's statement misses the point. While there may be an ample supply of natural gas in the United States, natural gas co-firing is not sufficiently available across the fleet. In 2017, only about one-third of coal-fired EGUs co-fired with *any* amount of natural gas.[218] That number has not changed substantially since that time. Of these units, only four percent actually co-fire significant amounts of natural gas for the purpose of generating electricity.[219] The vast majority of EGUs that have co-firing capability use the natural gas at very low levels for the purposes of starting up the boiler or holding it in "warm standby." And "using natural gas for ignition is not the same as co-firing with natural gas."[220] As one expert notes, "[i]n fact, it is common practice to shut down the natural gas igniters once the flame is established, so co-firing during normal operation is not as common a practice as the report would suggest. Several factors contribute to that practice including the supply of natural gas, quantity available, and operational aspects of the boiler."[221]

For those coal-fired EGUs that do not have access to natural gas, co-firing would be cost prohibitive because the cost of gaining access is approximately $4 to $10 million per mile of pipeline required. For example, at the New Madrid Power Plant (operated by PGen member Associated Electric Cooperative, Inc. ("AECI")) in Marston, Missouri, the closest pipeline with capacity and

[216] 88 Fed. Reg. at 33,338.

[217] *Id.*

[218] 84 Fed. Reg. at 32,544.

[219] *Id.*

[220] W. Morris & J. Weeda, Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on The Generation Alternative of Fuel Switching to Natural Gas at 3 (Aug. 3, 2023) ("Morris Gas Co-Firing Report") (Attachment K to these comments).

[221] *Id.*

pressure to support the plant is 46 miles away with an estimated capital cost in 2008 dollars of $213,798,000 to connect the pipeline to the plant (i.e., at a cost of $4,647,783 per mile). This cost estimate does *not* include additional costs for gas contracts and annual operating costs. Similarly, at AECI's Thomas Hill Energy Center in Clifton Hill, Missouri, the closest gas line is 14 miles away with an estimated capital cost in 2008 dollars of $59,500,000 to connect (i.e., at a cost of $4,250,000 per mile). Securing the right of way, surveying, and permitting (none of which is guaranteed) can be expected to take three years with construction taking another two years, and those timelines can be achieved only if there is not any litigation or challenges to the permits.[222]

For those facilities that can co-fire, an additional challenge may be acquiring sufficient natural gas to co-fire at higher rates on a consistent basis.[223] The requirement to co-fire natural gas in significant quantities would require the fuel to be available at all times (called "firm" access), which is even more expensive and less available than the non-firm form of access that is currently far more common at existing coal-fired EGUs.[224] Existing pipeline infrastructure to the plant may be unable to accommodate greater gas delivery, or pipeline gas pressure may be too low to deliver additional gas to the property line.[225] Further, gas is often unavailable at certain times of the year, which could

---

[222] *Id.* at 7.

[223] *See id.* at 4-9 (discussing problems and challenges arising from "Availability of Natural Gas During Periods of Inclement Weather and High Demand," the "Inadequacy of Natural Gas Transmission and Distribution Infrastructure for Fuel Switching," the "Difficulty and Cost Associated with Procuring Natural Gas Service at a Coal Plant," "Plant Design Challenges," and "Cost"). EPA has failed to analyze these problems and challenges.

[224] Comments of Great River Energy at 3 (Nov. 2, 2018), available in the docket for the Affordable Clean Energy Rule at EPA-HQ-OAR-2017-0355-23734; *see also* Morris Gas Co-Firing Report at 4 (noting, for example, that "[t]he supply of natural gas is already insufficient in the PJM region without the forced fuel switching and blending requirements that the EPA is proposing").

[225] *See* Morris Gas Co-Firing Report at 7 ("[T]he presence of a natural gas pipeline near a plant is not an indication of adequate capacity. For example, [one of the authors] … is experienced with the Coal Creek Station north of Bismarck, ND. [The map] shows a gas line just east of the plant, however, that line does not even have enough capacity to provide ignition fuel for the 1,100 MW coal plant."); *id.* (describing as mere "speculation" EPA's statement that "'[e]ven if a generator doesn't necessarily

result in a reliability problem.[226] Whether co-firing is viable ultimately requires a site-by-site analysis. Because EPA's proposed BSER is not achievable "for the industry as a whole" and not just a subset of sources, it is unlawful.[227]

In addition, as discussed above in Section IV.C with regard to hydrogen co-firing, the Supreme Court has said with regard to a coal-fired plant becoming a natural gas-fired plant (which is exactly what EPA is proposing to do here) that "EPA has never ordered anything remotely like that, and we doubt it could."[228] By 2030, any coal-fired steam generating unit that plans on operating after January 1, 2035, and retiring before January 1, 2040, must meet an emission limitation based on the co-firing of 40 percent natural gas. This turns a coal-fired plant into a hybrid coal/gas plant, which redefines the source; something that is not permissible under the CAA.[229] EPA must withdraw its BSER determination for medium-term coal-fired steam generating units.

E. EPA's Assumption that Technologies and Their Required Infrastructure Will Be Adequately Demonstrated and Achievable Several Years—and in Some Cases More Than a Decade—in the Future Is Not Reasonable and Violates the CAA.

In the Proposed Rules, EPA notes that in making an "adequately demonstrated" determination, it "'may make a projection based on existing technology,'" and it is not necessary "that the system 'must be in actual routine use somewhere.'"[230] While this is the case, EPA is constrained in that any projections that it makes are "subject to the restraints of reasonableness and

---

report burning natural gas, in many cases, coal-fired EGUs are located in the vicinity of other generating assets. In the cases where coal-fired EGUs are located near natural gas EGUs, they likely have access to an existing supply of natural gas.'").

[226] Comments of Duke Energy Business Services at 12-13 (Nov. 9, 2018), available in the docket for the Affordable Clean Energy Rule at EPA-HQ-OAR-2017-0355-24821.

[227] *National Lime Ass'n*, 627 F.2d at 431.

[228] *West Virginia v. EPA*, 142 S. Ct. at 2612 n.3.

[229] *See supra* note 215.

[230] 88 Fed. Reg. at 33,272 (quoting *Portland Cement*, 486 F.2d at 391)).

cannot be based on 'crystal ball' inquiry."[231] EPA's projections cannot be "wispy hopes based on no evidence at all."[232]

EPA's projections in the Proposed Rules are not reasonable and are rather "wispy hopes." While there may be instances where a technology is adequately demonstrated but some lead time may be needed "to design, acquire, install, and begin to operate" the technology (which might be allowed under the CAA),[233] it is not permissible under the CAA to prognosticate years (and even more than a decade) into the future and decide that a technology that is neither currently adequately demonstrated nor achievable will magically meet those legal thresholds at that time. Indeed, EPA's approach here is to assume that all of the problems that it has identified with regard to several of its BSER selections (CCS at both steam generating units and combustion turbines, hydrogen co-firing at combustion turbines, and natural gas co-firing at steam generating units) will be solved by the passage of time. This approach violates the requirements of section 111 that a system of emission reduction be adequately demonstrated and achievable at the time a rule is proposed and is arbitrary, capricious, and unlawful.

Once CCS, hydrogen co-firing, or other potential technologies meet the statutory requirements that a system of emission reduction be adequately demonstrated and achievable, EPA can then propose performance standards based on those technologies. Indeed, under section 111(b), EPA can always revise an NSPS at any time; it does not need to wait 8 years to do so.[234] Moreover, for existing sources, section 111(d) does not give EPA a deadline by which it must propose emission

[231] *Portland Cement*, 486 F.2d at 391.

[232] *NRDC v. Thomas*, 805 F.2d at 432.

[233] 88 Fed. Reg. at 33,273.

[234] CAA § 111(b)(1)(B), 42 U.S.C. § 7411(b)(1)(B) (specifying that EPA "shall, *at least* every 8 years, review and, if appropriate, revise such standards") (emphasis added).

guidelines for those sources.[235] EPA must wait until CCS and hydrogen co-firing meet the statutory requirements of section 111 before proposing standards of performance or emission guidelines based on these technologies. The Proposed Rules findings regarding adequate demonstration and achievability for these technologies are premature and should be withdrawn.

V. EPA's Timeline for Compliance with the Proposed Rules is Unrealistic.

The Proposed Rules contain timelines that are unrealistic and unachievable. The most egregious of these are the timelines for medium- and long-term existing coal-fired steam generating units (i.e., those coal-fired EGUs whose owners and operators intend to operate them past January 1, 2035, or January 1, 2040, respectively). Under the Proposed Rules, these medium- and long-term units must begin compliance with their relevant emission limitation beginning on January 1, 2030.[236] This deadline all but necessitates that existing coal-fired units will likely need to be subcategorized as either imminent- or near-term EGUs (and thus forced to retire no later than December 31, 2034) because the owners and operators of these units will not be able to install the technology and infrastructure needed to meet the emission limits for medium- or long-term units by 2030.

Coal-fired EGUs that are subcategorized as long-term must meet, by January 1, 2030, a presumptively approvable standard of performance that is based on a BSER of CCS with 90 percent capture of CO_2 and that reflects an 88.4 percent reduction in the unit's annual emission rate (in lb CO_2/MWh) from the unit's baseline.[237] Even assuming that this technology met the definition of adequately demonstrated and could be installed on a commercial scale (which it does not and cannot as described in detail in Section IV.B), it is infeasible to have CCS installed and operational on a unit in this timeframe. There are simply too many hurdles, including permitting, to be overcome. Unless

[235] *See id.* § 111(d), 42 U.S.C. § 7411(d).

[236] Proposed 40 C.F.R. § 60.5740b(a)(4)(viii)(A).

[237] 88 Fed. Reg. at 33,359, Table 5.

the owner or operator of a coal-fired EGU has already begun the process of pursuing CCS for the unit, *it is already too late*. First, it can take years simply to evaluate storage sites and conduct geologic testing.[238] This first step was undertaken for a CO_2 storage pilot project in northeastern Arizona and took three years and $5.7 million in investment—only to find out that the site had insufficient permeability to proceed with CO_2 injection.[239] Applications for Class VI wells, which are required for geologic storage of CO_2, are currently backed up at EPA.[240] Nationwide, only five Class VI permits have been issued, with a backlog of 33 permit applications pending.[241] States that have submitted an application to EPA for primacy in Class VI permitting are experiencing a similar backlog.[242] For example, Arizona submitted a primacy application to EPA in September 2022 that has not been acted upon. The Arizona Department of Environmental Quality believes EPA may act on this application by late 2023.

Another complicating—and time-consuming—factor occurs if the EGU is not located right above a geologic storage site. In those cases, pipelines need to be constructed to transport the CO_2 and depending on how close an EGU is to a storage facility, these pipelines may need to run hundreds of miles. The permitting and construction of pipelines takes years, faces fierce opposition,

---

[238] *See, e.g.*, EERC Report at 11 (EPA's "timeline shown in Figure 2 depicts 2.5 years for storage feasibility, site characterization, and permitting. This is an extremely optimistic and aggressive timeline. For example, the U.S. Department of Energy's CarbonSAFE Program assumes a 5-year timeline to address feasibility, characterization, and permitting. Even for states with Class VI primacy such as North Dakota, storage feasibility, site characterization, and permitting could take up to 4.5 years.").

[239] *See supra* p. 40 & notes 146, 147.

[240] *See* EERC Report at 11 ("For states without primacy, storage feasibility, site characterization, and permitting could take up to 6.5 years based on historical EPA permitting timelines from the two approved EPA UIC Class VI permits.").

[241] Hunton Andrews Kurth, Class VI Program Permit Tracker, https://www.huntonak.com/en/class-vi-program-permit-tracker.html.

[242] *Id.*

and is extremely expensive.[243] Recent experience of one PGen member constructing pipelines resulted in a cost of $5 to $10 million per mile. The permitting and construction of pipelines also takes many years.[244] This is compounded, for projects that must be completed in the next few years (i.e., by 2030) by supply chain issues.[245]

Similar problems also arise with the presumptively approvable standard of performance for medium-term coal-fired EGUs. The standard of performance for those units is based on co-firing 40 percent natural gas. Most coal-fired EGUs do not have access to natural gas, which means that a pipeline would need to be constructed. As just discussed with regard to CCS, building a pipeline is an endeavor that may not be approved and will take years to permit and construct even if it is ultimately approvable. Even for those coal-fired EGUs that do have access to natural gas, they may not be able to obtain the quantities of natural gas needed to co-fire at this level on a reliable basis (or even at all depending on the pipeline and infrastructure).[246]

Daniel Walsh, Senior Director for Generation Research and Development at PGen member the National Rural Electric Cooperative Association, conducted an in-depth analysis of the timeline likely needed for a CCS project. He concludes, "[b]ased on the information and research obtained,

---

[243] The Mountain Valley Pipeline that is proposed for construction in North Carolina and Virginia is an example. Work on that pipeline began in May 2018—more than five years ago. MVP Southgate, Overview, https://www.mvpsouthgate.com/overview/. The pipeline is still not completed and has been the subject of controversy and litigation, including before the Supreme Court. J. Kruzel, Reuters, *US Supreme Court removes obstacle to Mountain Valley Pipeline* (July 27, 2023), https://www.reuters.com/legal/us-supreme-court-removes-obstacle-mountain-valley-pipeline-2023-07-27/.

[244] EERC Report at 11-12 ("Depending on the route of the pipeline, permits for water body crossings, federal lands, and the Army Corps of Engineers can take a year or more to acquire, if the permit is allowed at all. In addition, agreements with landowners for rights of way … for the pipeline can take a year or longer, depending on the length of the pipeline. In all, the listed time of 2.5 years for pipeline feasibility, design, and permitting appears to be overly optimistic.").

[245] *Id.* at 12.

[246] Morris Gas Co-Firing Report at 7.

an accurate time for the construction of a project is more **in the range of 10-12 years after inception**."[247] Because the timeline for owners and operators of coal-fired EGUs to have all of this infrastructure and permitting completed by January 1, 2030—and have all of the technology working properly by that date—is infeasible, it will almost certainly lead owners and operators to have to subcategorize their units differently: as either imminent-term (meaning the unit will have to retire no later than January 1, 2032) or as near-term (meaning the unit will have to retire no later than January 1, 2035, *and* agree to restrict the unit's capacity factor to 20 percent) regardless of whether the unit has more remaining useful life and regardless of whether the unit is needed to meet electric reliability needs.

VI. The Proposed Rules Violate the Major Questions Doctrine, which the Supreme Court Warned EPA About in West Virginia v. EPA.

EPA's two prior rules regulating GHG emissions from existing EGUs under section 111(d) of the CAA—the Clean Power Plan and the Affordable Clean Energy Rule—were examined by the U.S. Supreme Court last year in *West Virginia v. EPA*.[248] The Court held "there are 'extraordinary cases' that call for a different approach" than deferring to an administrative agency such as EPA.[249] These are "cases in 'which the history and breadth of the authority that the agency asserted' and the 'economic and political significance' of that assertion, provided a 'reason to hesitate before concluding that Congress meant to confer such authority."[250] Although the Court had applied this rationale in previous cases, it gave a name to this principle—the Major Questions Doctrine—for the first time in *West Virginia*.

[247] Walsh Report at 4 (emphasis in original).

[248] 142 S. Ct. at 2587. The rule under review by the Supreme Court in *West Virginia* was the Affordable Clean Energy Rule and that rule's repeal of the Clean Power Plan.

[249] *Id.* at 2608 (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159 (2000)).

[250] *Id.*

In the Clean Power Plan, EPA relied on an approach based on "generation shifting" where non-GHG emitting forms of generation such as wind and solar would be favored over lower-GHG emitting natural gas-fired generation, followed last by coal-fired generation (which has higher GHG emissions than gas-fired generation). The Supreme Court found in *West Virginia* that the Clean Power Plan's approach violated the major questions doctrine for four reasons. First, the Clean Power Plan differed significantly in approach from all previous rules by EPA under section 111(d), which had relied on a BSER that was based on emissions reducing "measures that would reduce pollution by causing the regulated source to operate more cleanly…. [EPA] had never devised a cap by looking to a 'system' that would reduce pollution simply by 'shifting' polluting activity from dirtier to cleaner sources."[251] The Court found that this "unprecedented" view of EPA's authority "effected a 'fundamental revision of the statute, changing it from [one sort of] scheme of regulation' into an entirely different kind."[252] This new interpretation would allow EPA to:

> demand much greater reductions in emissions based on a very different kind of policy judgment that it would be "best" if coal made up a much smaller share of national electricity generation. And on this view of EPA's authority, it could go further, perhaps forcing coal plants to 'shift' away virtually all of their generation—*i.e.*, to cease making power altogether.[253]

Second, the Court found that EPA dictating the optimal mix of energy sources is not within the Agency's traditional area of expertise, and the Court said "[t]here is little reason to think Congress assigned such decisions to the Agency," especially given that "EPA itself admitted … '[u]nderstand[ing] and project[ing] system-wide … trends in areas such as electricity transmission, distribution, and storage' requires 'technical and policy expertise *not* traditionally needed in EPA

[251] *Id.* at 2610 (internal quotation and citation omitted).

[252] *Id.* at 2612 (quoting *MCI Telecomms. Corp. v. AT&T*, 512 U.S. 218, 231 (1994)).

[253] *Id.*

regulatory development.'"[254] The Court found "little reason to think Congress assigned such decisions" that are outside EPA's expertise to the Agency, and "'[w]hen [an] agency has no comparative expertise' in making certain policy judgments, [the Court has] said, 'Congress presumably would not' task it with doing so."[255]

Third, the Court went on to "find it 'highly unlikely that Congress would leave' to 'agency discretion' the decision of how much coal-based generation there should be over the coming decades," especially "in the previously little-used backwater of Section 111(d)."[256] The types of "basic and consequential tradeoffs"—decisions that would be required in making such a decision—"are ones that Congress would likely have intended for itself."[257]

Finally, the Court found it noteworthy that Congress had "'considered and rejected' multiple times" proposals to amend the CAA to create a cap-and-trade program such as that promulgated in the Clean Power Plan or "to enact similar measures, such as a carbon tax."[258] For all of these reasons, the Court found that the major questions doctrine applied and held that section 111(d) does not contain the "'clear congressional authorization'" that is required to regulate in the manner that EPA tried to do under the Clean Power Plan.[259]

As detailed below, EPA's Proposed Rules do not fix the legal infirmities identified by the Supreme Court in *West Virginia*, and as a result the Proposed Rules violate the major questions doctrine and are unlawful. While the Clean Power Plan was more forthright about its generation

---

[254] *Id.* at 2612 (quoting EPA, Fiscal Year 2016 Justification of Appropriation Estimates for the Committee on Appropriations 213 (2015)) (emphasis in original).

[255] *Id.* at 2612-13 (quoting *Kisor v. Wilkie*, 139 S. Ct. 2400, 2417 (2019)).

[256] *Id.* at 2613 (quoting *MCI*, 512 U.S. at 231)).

[257] *Id.*

[258] *Id.* at 2614 (quoting *Brown & Williamson*, 529 U.S. at 144).

[259] *Id.* (quoting *Utility Air Regulatory Group v. EPA*, 573 U.S. 302, 324 (2014)).

shifting approach and its aim to reduce fossil fuel-fired electric generation and "dictate the optimal mix of energy sources nationwide,"[260] the Proposed Rules lead to the exact same results: a shifting away from fossil fuel-fired generation and a dictation of what EPA views as the optimal mix of energy sources in the United States.

First, although EPA now bases the Proposed Rules on emissions reducing technologies and "measures that would reduce pollution by causing the regulated source to operate more cleanly," the fact of the matter is that these technologies—although promising—are not yet adequately demonstrated, are not achievable, and are not cost-effective as discussed in detail in Section IV, even with the IRA *possibly* providing financial assistance in some circumstances.[261] And even if these technologies were adequately demonstrated, achievable, and cost-effective (which they are not), the timetable (particularly for coal-fired EGUs)[262] for implementing these technologies and measures is so unreasonable that it likely cannot be met. The end result is that owners and operators will have little choice but to either retire units prematurely or severely curtail their use (and then retire prematurely) in order to comply with the Proposed Rules.

Second, the Proposed Rules continue to dictate what EPA views as the optimal mix of energy sources within the United States. The rules essentially result in: little to no coal-fired

---

[260] *Id.* at 2613.

[261] The possibility that a project may receive funding under the IRA is just that: a possibility. EPA cannot count on these funds to be available for every project in its cost-benefit analysis. *See, e.g.*, Morris CCS Report at 8-10.

[262] Indeed, the fact that EPA requires coal-fired EGUs to begin compliance with very stringent emissions requirements beginning in 2030, while gas-fired EGUs remain in a "business as usual" stance until later, shows that EPA is again prioritizing gas-fired generation over coal-fired generation—just as it did in the Clean Power Plan. *Compare* Proposed 40 C.F.R. § 60.5740b(a)(4)(viii)(A) (requiring coal-fired steam generating units to begin final compliance with the standard of performance by January 1, 2030), *with* Proposed 40 C.F.R. § 60.5740b(a)(4)(viii)(B), (C) (requiring gas-fired combustion turbines to begin final compliance with the standard of performance by either January 1, 2032, or January 1, 2035).

generation, with gas-fired generation used only for peaking purposes and to back up renewable generation. The Supreme Court clearly said EPA does not have authority in this regard, and the Proposed Rules violate the major questions doctrine.

For example, if an owner or operator wants a coal-fired unit to operate in 2040 and beyond, it must meet—beginning in 2030—an emission limit based on CCS.[263] As discussed in Section IV.B, while CCS is a promising technology, it is neither adequately demonstrated nor available. Moreover, the timeframe is unrealistic, as discussed in Section V. In effect, this requirement forces those owners or operators to subcategorize their coal-fired steam generating units as imminent-term (committing to a retirement before 2032)[264] or near-term (committing to a retirement before 2035 and a restriction that the unit cannot operate above a 20 percent capacity factor).[265] For those coal-fired EGUs that have ready-access to a firm supply of natural gas, those units might be able to operate until 2040 by co-firing natural gas[266] (which gives rise to other legal issues regarding fuel switching and redefinition of the source).

The situation is similar for new gas-fired EGUs. EPA's rules have the effect of allowing construction of only "peaking" units to back up renewable generation. All other construction requires a unit to eventually be able to co-fire low-GHG hydrogen (for which there is no reliable supply and for which there is no infrastructure to transport it even if there were a reliable supply) or to install CCS (something that has never been done at an electric utility CT to date). Existing gas-fired combustion turbines fare no better, with baseload units (the ones most needed to ensure

[263] *See, e.g.*, *id.* § 60.5740b(a)(4)(viii)(A).

[264] *Id.* § 60.5740b(a)(1)(D).

[265] *Id.* § 60.5740b(a)(1)(C).

[266] *Id.* §§ 60.5740b(a)(1)(B), 60.5775b(c)(2).

electric reliability) restricted to operating at half their capacity or being required to co-fire low-GHG hydrogen beginning in 2032 or to install CCS by 2035.

Third, it continues to be "'highly unlikely that Congress would leave' to 'agency discretion' the decision of how much coal-based generation there should be over the coming decades," and the provision of the CAA on which EPA relies as the authority for the Proposed Rules continues to be "the previously little-used backwater of Section 111(d)."[267] No previous EPA rulemaking under section 111(d) has ever required technology that is not yet ready and available—nor has EPA ever required under section 111(d) the installation of these not yet available technologies years—and in some cases more than a decade—out in the future.

Fourth and finally, Congress continues to wrestle with the issue of climate change and how to address it, with several recent bills showing widely disparate views on the issue.[268] Congress has consistently rejected programs like the one proposed here that would severely limit fossil fuel-fired electric generation in the United States.[269] While Congress did recently enact the IRA, that statute is focused on promoting the development of the nascent and promising technologies of CCS and

[267] *West Virginia v. EPA*, 142 S. Ct. at 2613.

[268] *See, e.g.*, Preparing Superfund for Climate Change Act of 2023, H.R. 1444, 118th Cong. (2023) (bill that would require consideration of climate change when selecting remedial actions for the cleanup of Superfund sites); To provide for the withdrawal of the United States from the United Nations Framework Convention on Climate Change, and for other purposes, H.R. 2781, 118th Cong. (2023); Coastal State Climate Preparedness Act of 2023, H.R. 2735, 118th Cong. (2023) (bill that would direct the Commerce Department to establish a coastal climate change adaptation preparedness and response program that would be voluntary for states); Green New Deal for Health Act, H.R. 2764, 118th Cong. (2023) (bill that would create programs to mitigate the health effects of climate change); Real Emergencies Act, S.2118, 118th Cong. (2023) (bill that would prohibit the president from declaring a national emergency on the basis of climate change).

[269] *See, e.g.*, American Clean Energy and Security Act, H.R. 2454, 111th Cong. (2009) (climate cap-and-trade bill that did not pass the Senate); Clean Energy Jobs & American Power Act, S.1733, 111th Cong. (2009) (rejected cap-and-trade legislation).

hydrogen co-firing that are mandated by the Proposed Rules and not on the direct limitation or curtailment of fossil fuel-fired electric generation.[270]

EPA also exceeds its authority under the CAA by setting NSPS and presumptively approvable emission limits for existing sources that do not go into effect for many years (in some instances more than a decade in the future) and bases these emission limitations on technologies it anticipates being demonstrated far in the future. The CAA speaks to technology that "has been" adequately demonstrated—not "will be" adequately demonstrated. Further, EPA's attempt to transform coal-fired EGUs into gas-fired EGUs and to transform gas-fired EGUs into hydrogen-fired EGUs in the future confronts an issue of major economic and political significance. If Congress had wanted to give this authority to EPA, it was required to do so clearly and unambiguously. This is not the case, and Congress cannot give EPA such vast authority through purported ambiguities in its phrasing.

For all of these reasons, the Proposed Rules violate the major questions doctrine. EPA should withdraw the Proposed Rules and re-propose rules that do not run afoul of the doctrine and that meet the standards of section 111 of the Clean Air Act in terms of being based on a system of emission reduction that is adequately demonstrated, achievable, and cost-effective. EPA can always revise a performance standard under section 111(b) of the CAA at any time, and it could do so if and when the technologies of CCS, hydrogen combustion, or other feasible technologies meet this important legal standard. Moreover, EPA does not have a deadline under section 111(d) to establish

[270] *See, e.g.*, The White House, Building a Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investments in Clean Energy and Climate Action at 9 (Jan. 2023), https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf (The IRA "is the most ambitious investment in clean energy in our nation's history. It includes more than 20 new or modified tax incentives and tens of billions of dollars in grant and loan programs to unleash new clean energy technology investment and deployment and supercharge our transition to a clean energy economy.").

emission guidelines for existing EGUs, and it should wait for these or other technologies to be developed further before requiring them.

VII. The Applicability Dates for the Proposed Rules are Incorrect as a Matter of Law.

EPA correctly notes in the Proposed Rules that "the CAA defines an 'existing source' as 'any stationary source other than a new source,'" and further correctly notes that the proposed emission guidelines for existing sources "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."[271] This is the correct analysis and conclusion under the CAA. Yet, on June 12, 2023, EPA issued a "Memo to the Docket" entitled "Applicability of Emission Guidelines to the Existing Stationary Combustion Turbines: FAQs" ("Applicability Memo").[272] In this document, EPA inexplicably changes course and "clarifies" that "[s]tationary combustion turbines that commenced construction or reconstruction before May 23, 2023, are existing sources that may be affected EGUs under the proposed UUUUb [the proposed emission guideline]."[273] EPA now says that the term "EGUs" in the preamble refers only to steam generating units (i.e., utility boilers). This is not what the proposed regulatory text says. Section 60.5700b of the proposed regulatory text says explicitly that a "natural gas fired stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU." EPA's position in the Applicability Memo conflicts with this explicit proposed language.

EPA correctly cites section 111(a)(6) of the CAA, which defines an "existing source" as "any stationary source other than a new source."[274] This statutory text is unambiguous. A source cannot

[271] 88 Fed. Reg. at 33,342.

[272] Docket ID No. EPA-HQ-OAR-2023-0072-0143.

[273] Applicability Memo at 2.

[274] CAA § 111(a)(6), 42 U.S.C. § 7411(a)(6).

be both "new" and "existing." Stationary combustion turbines constructed after January 8, 2014, are "new" sources that complied with Subpart TTTT. These units cannot be "existing"—and thus subject to a section 111(d) emission guideline—under the plain text of the CAA. A "new source" is "*any* stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing *a* standard of performance under this section which will be applicable to such source."[275] Combustion turbines constructed after January 8, 2014, whose CO_2 emissions were subject to Subpart TTTT are "new sources" under section 111—and therefore cannot be existing sources—because those sources are already subject to "*a* standard of performance" for CO_2 under section 111.

In addition, it is arbitrary and capricious for EPA to say (correctly) that steam generating units that complied with Subpart TTTT are "new" sources (and thus not subject to the proposed emission guidelines) while stationary combustion turbines that complied with that same provision are "existing" sources that are subject to the proposed emission guidelines. EPA must make clear that any EGU—whether a steam generating unit or a stationary combustion turbine—that commenced construction prior to January 14, 2014 (or that commenced a reconstruction or modification after June 18, 2014) and was subject to Subpart TTTT is *not* an existing source for the purposes of the proposed emission guideline. The proposed emission guideline should apply only to EGUs that commenced construction prior to those dates (and that did not undergo a modification or reconstruction after June 18, 2014). Any other interpretation is contrary to the plain language of the CAA and is unlawful.

[275] *Id.* § 111(a)(1), 42 U.S.C. § 7411(a)(1) (emphasis added).

VIII. The Proposed Rules Impermissibly Restrict States' RULOF Determinations.

As PGen noted in its comments on EPA's proposed revisions to the section 111(d) implementation regulations of Subpart Ba,[276] Congress directed that EPA's implementing regulations under section 111(d) "*shall* permit the State in applying a standard of performance to any particular source under a plan submitted [under section 111(d)] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[277] While EPA has the authority to approve or disapprove of a state plan, it cannot unduly limit a state's discretion to take RULOF into account.

EPA should not unduly restrict states' ability to examine RULOF. In the interest of finding a least-cost pathway to reducing CO_2 emissions, RULOF is an important aspect of the section 111(d) analysis. Despite this, in the Proposed Rules, EPA is putting too many restrictions on a state's remaining useful life analysis to such an extent that states will be unable to take advantage of the ability that Congress gave them to have less stringent standards in certain circumstances. For example, EPA's proposal that sources that have a less stringent emission limitation based on a state's remaining useful life analysis cannot participate in an emissions trading program is arbitrary and capricious and not grounded in the statute. As discussed in more detail in Section IX.B, there is no compelling reason why a source subject to RULOF cannot be included in a trading program. The emissions cap for that source simply needs to be calculated (and added to the overall cap) based on its less stringent RULOF-based emission limitation.

[276] Comments of the Power Generators Air Coalition on EPA's Proposed Rule Entitled "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Action Section 111(d)," Docket ID No. EPA-HQ-OAR-2021-0527-0097 (Feb. 27, 2023). These comments are incorporated herein by reference and attached as Attachment L.

[277] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1) (emphasis added).

In the Proposed Rules, EPA also implies that a state needs to invoke the RULOF provisions *only* when a state is proposing a less stringent emission standard for a designated facility, and RULOF does not apply if a state is achieving EPA's presumptive level of stringency through means other than the BSER identified by EPA.[278] Using this same logic, EPA should similarly make clear that if a state plan results in the same outcome in terms of environmental benefits that would have been achieved under EPA's presumptive level of stringency, that state plan should be approved by EPA as "satisfactory."[279] This is particularly important for any state that may use flexible compliance mechanisms such as a cap-and-trade program where the overall stringency of the program is achieved through the emissions cap, but a particular unit may exceed the equivalent of its emission limitation and comply by obtaining and surrendering allowances or a program like emissions averaging where a particular unit may exceed the equivalent of its emission limitation but comply by averaging its emissions with a unit that has over-complied with its emission limitation. This principle was implied in the preamble to the proposed revisions to the Subpart Ba section 111(d) implementation regulations where EPA stated that:

> [T]he proposed RULOF provisions … would apply where a state intends to *depart* from the presumptive standards in the [emissions guideline] and propose a less stringent standard … and not where a state intends to *comply* by demonstrating that a facility or group of

[278] 88 Fed. Reg. at 33,383 (noting "a State may not invoke RULOF to provide a less stringent standard of performance for a particular source if that source cannot apply the BSER but can reasonably implement a different system of emission reduction to achieve the degree of emission limitation required by the EPA's BSER determination").

[279] It should be noted that EPA's review of a state plan under section 111(d) (i.e., to determine whether the plan is "satisfactory") is less rigorous than its review of state implementation plans under section 110 of the CAA (which requires that all statutory criteria be met). *Compare* CAA § 111(d)(2)(A) (noting EPA has authority to prescribe a federal plan "where the State fails to submit a satisfactory plan") *with* CAA § 110(k)(3) (noting EPA must approve a state implementation plan "if it meets all of the applicable requirements of this chapter"). And even with regard to EPA's review of state implementation plans under section 110, the Agency's role is "limited," *Texas v. EPA*, 690 F.3d 670, 675 (5th Cir. 2012), and "confine[d] … to the ministerial function of reviewing [state implementation plans] for consistency with the Act's requirements," *Luminant Generation Co. v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012).

> facilities subject to a state program would, in the aggregate, achieve equivalent or better reductions than if the state instead imposed the presumptive standards required under the [emissions guideline] at individual designated facilities.[280]

EPA should make this point explicitly in the emission guidelines.

In addition, PGen disagrees with EPA's statement in the Proposed Rules that because EPA "considered impacts on the energy sector as part of its BSER determinations," that energy impacts "would not be [an] appropriate basis for invoking RULOF."[281] This conflicts with the plain language of the CAA, which expressly says that "nonair quality health and environmental impact and energy requirements" must be taken into account in setting a standard of performance.[282] Because states set the standard of performance for existing sources under section 111(d), the statute specifically *requires* them to take energy requirements into account, and anything in the Proposed Rules that restricts their ability to do that is unlawful and contrary to the plain language of the CAA.[283]

As PGen stated in its Pre-Proposal Comments, existing fossil fuel-fired EGUs that rarely operate should be allowed to comply with alternative emission limitation requirements, and "[t]hese units could be subject to limitations on the amount they may operate in a given year."[284] There may be important energy requirements (i.e., reliability reasons) why a state may want to keep open a plant that is used rarely. Companies will not be willing to invest necessary sums in such a unit and thus under the Proposed Rules will be forced to retire the unit. Rather than having the unit retire, states may decide it is better policy to place an operating restriction on the unit that limits its use—yet

---

[280] 87 Fed. Reg. 79,176, 79,198 (Dec. 23, 2022) (emphasis in original).

[281] 88 Fed. Reg. at 33,382 n.628.

[282] CAA § 111(a)(1); 42 U.S.C. § 7411(a)(1).

[283] In addition, EPA is not the expert on energy resource adequacy and reliability, and its attempt to evaluate the impact of the Proposed Rules on the power sector is woefully inadequate. *See infra* Section XI (discussing EPA's use of the IPM model).

[284] PGen Pre-Proposal Comments at 7.

leaves it available when needed. Allowing states to invoke RULOF to allow for a less stringent standard for these facilities to preserve reliability is permissible under the statute because the state is properly taking energy requirements into account. In these instances, where a state plan that contains a less stringent emission limitation and a restriction on the unit's operating capacity based on RULOF for a designated facility, PGen agrees that any such capacity restriction must be included in the state plan as an enforceable requirement.

Further, states should be allowed to modify a subcategory in their state plans to address RULOF issues. For example, if a coal-fired steam generating unit is planning to retire at the end of 2032, and the state determines that the unit is needed for reliability purposes at greater than a 20% capacity factor, the state should be allowed to subcategorize that unit as an "imminent-term" unit even though it will operate a little longer than that subcategory's December 31, 2031 retirement deadline. Under this hypothetical, the state can justify this modification of the subcategory under two separate RULOF grounds: (1) remaining useful life—it would make no sense to require the owner and operator of the unit to invest substantial sums at the unit given it would be retiring soon; and (2) energy requirements—the state can demonstrate that the unit is needed at a higher capacity than the 20% restriction placed on near-term units. EPA should make clear in the final emissions guidelines that states have the authority to modify the subcategories when justified by RULOF considerations.

IX. EPA Should Assist the States by Providing a Model Trading Rule Based on Mass-Based Presumptively Approvable Emission Limits that States Can Adopt.

For all the reasons discussed herein, PGen believes that the Proposed Rules are unlawful and should be withdrawn by EPA. If EPA decides nevertheless to proceed to finalize the rules (or proposes new rules), PGen strongly supports EPA's proposal "to allow states to incorporate averaging and emission trading into their State plans, provided that states ensure that use of these compliance flexibilities will result in a level of emission performance by the affected EGUs that is

equivalent to each source individually achieving its standard of performance."[285] In its Pre-Proposal Comments, PGen set out a recommended approach that it asked EPA to adopt in its emission guideline addressing GHG emissions from existing fossil fuel-fired EGUs.[286] The recommended approach had three main components that PGen requested: (1) EPA should make clear that states have the authority to offer a wide array of flexible options (such as emissions averaging and emissions trading) to assist sources in meeting their performance standards;[287] (2) EPA should follow the approach that it has taken in prior rulemakings and develop a model trading rule that incorporates these types of flexible options that would provide states with an easy way to participate in a cap-and-trade program if they choose to do so;[288] and (3) EPA should convert any rate-based emission limitations to a mass-based emission rate.[289] EPA partially adopted this approach in the Proposed Rules by making clear that states do have the ability to rely on flexible options for compliance. Unfortunately, however, EPA did not issue a model trading rule for states to adopt or convert the presumptively approvable rate-based emission limits into mass-based limits. PGen urges EPA to do these things and reiterates that doing so is a good policy decision.

A. EPA Should Issue a Model Trading Rule for Existing Sources that States May Opt Into and that Would Be a Fully Approvable and Automatic State Plan.

As EPA has recognized, "[a]nnual progress reports demonstrate that EPA trading programs have been successful in mitigating the problems they were designed to address, exhibiting significant

[285] 88 Fed. Reg. at 33,392.

[286] PGen Pre-Proposal Comments at 5.

[287] *Id.* at 5, 8.

[288] *Id.* at 5, 9.

[289] *Id.* at 5, 15-16.

emission reductions and extraordinarily high levels of compliance."[290] Compliance flexibility also provides incentives for sources to pursue additional emission reductions beyond those required by a rule. When EPA promulgated the Clean Air Mercury Rule in 2005,[291] it established a model trading program as an implementation tool to assist sources in meeting their performance standards, and states had a choice regarding whether to participate in the trading program.[292] Participation in the trading program was "a fully approvable control strategy for achieving all of the emissions reductions required under the final rule in a more cost-effective manner than other control strategies."[293] States were also permitted to deviate from the model rule in certain respects "to best suit their unique circumstances."[294] EPA also followed this approach in the Clean Power Plan where the Agency proposed a model trading rule that would also serve as a federal plan in the event a state failed to submit a satisfactory state plan.[295] EPA should follow this approach again.

The vast majority of states do not have the experience with emissions trading programs that EPA has, nor do most states have the resources that are needed to create these types of programs. As EPA acknowledges, there are numerous procedures and systems that states would need to

[290] 88 Fed. Reg. at 33,393 (citing EPA, Power Sector Programs Progress Report (2021), https://www3.epa.gov/airmarkets/progress/reports/pdfs/2021_full_report.pdf).

[291] 70 Fed. Reg. 28,606 (May 18, 2005). The U.S. Court of Appeals for the D.C. Circuit vacated the Clean Air Mercury Rule for reasons having nothing to do with the model trading program. *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

[292] 70 Fed. Reg. at 28,624-32.

[293] *Id.* at 28,625.

[294] *Id.*

[295] 80 Fed. Reg. 64,966 (Oct. 23, 2015). Although the Clean Power Plan was stayed by the Supreme Court and the basis for its BSER ultimately rejected by that court in *West Virginia v. EPA*, nothing in the Court's rationale rejects the approach PGen urges here of the Agency issuing a model trading rule.

establish to put an emissions trading program into place.[296] The preparation of a model trading rule that states could adopt would bypass the need for states to figure all of this out for themselves. And as EPA notes, it has extensive experience with allowance trading programs and already has the infrastructure for reporting and compliance tracking in place.[297]

States that choose to adopt any model trading rule that EPA issues would also benefit from the certainty of having automatically approvable state plans. This approach would also benefit states that have only a handful of affected EGUs (or as in the case of North Dakota, only one affected EGU). For these states, compliance flexibility is non-existent unless there can be emission trading or averaging with other states. If a state desires to cooperate with other states, the approach of having a model trading rule would relieve them of the time, legwork, and uncertainty involved in coordinating and negotiating with dozens of other jurisdictions. This approach has yet another advantage in that it provides EPA with a federal plan that it can easily use if a state either fails to submit a state plan or in the event a state plan is not deemed to be satisfactory by EPA.

PGen also encourages EPA to consider offering incentives as part of its model rule to reward early action and to ensure credits remain for some period of time when units shut down, as has been done in other trading programs like the Cross-State Air Pollution Rule, the Clean Air Interstate Rule, and the NOx SIP Call. EPA should want to encourage states to adopt these types of flexible implementation programs as a policy matter. As EPA noted when it proposed the Clean Air Mercury Rule, the Agency's "significant experience" with cap-and-trade programs for utilities has

[296] 88 Fed. Reg. at 33,395 (noting states need to establish: compliance timeframes, the mechanics to demonstrate compliance, monitoring and reporting requirements, a tracking system for tradable compliance instruments, and a method for distribution of allowances in a mass-based system).

[297] *Id.*

shown that such programs cause emissions to fall *below* the mandated cap, despite increased electric generation, while "maximizing overall cost-effectiveness."[298]

Ensuring that states have maximum flexibility by being able to adopt a model trading rule will ease a lot of the issues that exist at this time with the Proposed Rules and with the regulation of GHG emissions from existing fossil fuel-fired EGUs generally. For example, a cap-and-trade program will help preserve reliability during the energy transition and will help keep electricity affordable because it will allow fossil fuel-fired EGUs that are rarely used to continue to be operated for the purpose of stabilizing the grid during times of peak load (such as during times of extreme heat or cold or because of an extreme weather event) because the owners and operators of those EGUs can forgo significant capital investment in those units and instead buy allowances to cover those units' limited emissions. In addition, a cap-and-trade program will help by providing time for technologies that are showing promise to mature and for funding from the IRA to be deployed, which will help spur advancements in technology development.

B. EPA Should Not Unduly Restrict Emissions Trading.

In the Proposed Rules, EPA asks for feedback on how a cap-and-trade program could be structured for existing affected sources.[299] PGen encourages EPA to issue a model rule that is broadly applicable across all affected fossil fuel-fired EGUs, regardless of their subcategory and regardless of whether they are steam generating units or stationary combustion turbines. To do this, EPA could examine each affected EGU and determine what its historical operating profile is (i.e., how much it operates annually on average) by looking back at its operations over a given time

[298] 69 Fed. Reg. 4652, 4697 (Jan. 30, 2004); *see also id.* (noting that trading "maximizes the cost-effectiveness of the emissions reductions in accordance with market forces" and that "[s]ources have an incentive to endeavor to reduce their emissions below the number of allowances they receive").

[299] *See generally* 88 Fed. Reg. at 33,393-96.

period. PGen suggests that a three- to five-year lookback period would be beneficial (such as perhaps a lookback period of 2018-2022) and suggests that any lookback period should extend back before 2020 to ensure the numbers are not skewed in an unrepresentative fashion by the COVID-19 pandemic. Once EPA determines a unit's annual historical average operations, it can then determine what the unit's annual budget should be under the model trading program by calculating its CO_2 emissions over that period of time using the presumptively approvable emission limitation for that type of unit.

EPA suggests that it might be inappropriate to include EGUs for which the BSER is "routine methods of operation" (e.g., imminent-term and near-term coal-fired steam generating units) in a trading program.[300] While calculating the emissions budget for those units might be slightly more complicated because it would be very unit-specific (as opposed to relying on a presumptively approvable emission limitation), it would not be impossible to do. In addition to determining a unit's historical average operations over a given period of time, EPA (or the state) would also determine the unit's historical emissions over that period of time. For example, for a near-term coal-fired EGU, EPA would examine its historical emissions over the relevant period of time and then restrict those emissions based on a 20 percent capacity factor (a requirement for the near-term subcategory) to determine the emissions budget for the unit. The allowances for that EGU would disappear from the program beginning in 2035, which is the date by which a near-term unit needs to commit to retire.

Similarly, EPA's belief that "it would not be appropriate to allow affected EGUs with less-stringent source-specific standards based on RULOF to comply with those standards of performance through trading," is misplaced.[301] There is no valid reason why an EGU subject to a

[300] *Id.* at 33,393.

[301] *See id.* at 33,393-94.

source-specific standard based on a RULOF determination could not be included in a trading program. Again, the emissions budget for that EGU would be determined based on its historical average operations and its less-stringent, RULOF-based emission rate as determined by the state.

All of these calculations would lead to an emissions cap for the state (or a collection of states if part of an EPA model trading rule or an interstate trading program). As long as the emissions cap is not exceeded, the end result is the same in terms of environmental benefits and reduced GHG emissions as it would be if there were not any trading involved. In fact, the end result might be even better because as EPA acknowledges:

> In general, emission trading programs provide flexibility for EGUs to *secure emission reductions at a lower cost relative to more prescriptive forms of regulation*. Emission trading can allow the owners and operators of EGUs to *prioritize emission reduction actions where they are the quickest or cheapest to achieve while still meeting electricity demand and broader environmental and economic and performance goals*. These benefits are heightened where there is a diverse set of emission sources (e.g., variation in technology, fuel type, age, and operating parameters) included in an emission trading program. This diversity of sources is typically accompanied by differences in marginal emission abatement costs and operating parameters, resulting in heterogeneity in economic emission reduction opportunities that can be optimized through the compliance flexibility provided through emission trading. In addition, the EPA has observed, with the support of multiple independent analyses, that *there is significant evidence that implementation of trading programs prompted general innovation and deployment of clean technologies that reduce emissions and control costs*.[302]

It would also not be difficult to control for the different subcategories. As shown above, the emissions budget for a near-term coal-fired steam generating unit would be its historical emissions rate calculated with a capacity factor limitation of 20 percent, with the allowances for that unit being removed from the program beginning in 2035 (the year by which a near-term unit commits to retire). Similarly, a medium-term steam generating unit would have an emissions budget that would

[302] *Id.* at 33,393 (emphases added).

be calculated by determining its historical emission rate less a 16 percent reduction (the presumptively approvable standard of performance for this type of EGU), with the allowances for that unit being removed from the program beginning in 2040 (the year by which a medium-term unit commits to retire under the Proposed Rules).

PGen urges EPA not to include dynamic budgeting and to allow banking of allowances in any model trading program under the Proposed Rules because it will stifle the incentives under the market to retire units early or to reduce utilization at units. Those incentives exist only if banking is allowed and if budgets do not change. Moreover, there is no need for dynamic budgeting because the program becomes increasingly more stringent as time passes with key years where the overall emissions budget will reduce occurring in 2032, 2035, 2038, and 2040.

C. EPA Should Provide States with Alternative Mass-Based Presumptively Approvable Emission Limits.

Any model trading rule developed by EPA should be mass-based. As EPA notes, "[o]wners and operators of EGUs, utilities, and State agencies … have extensive familiarity with mass-based emission trading, which could make the design and implementation of a mass-based trading program as part of a State plan relatively straightforward."[303] When EPA proposed the Clean Power Plan in 2014, it provided states with a technical support document to assist states with translating emission rate-based goals to a mass-based equivalent.[304] In response to states' requests for further assistance, EPA converted the rate-based goals of each state into a mass-based goal.[305] EPA noted

[303] *Id.* at 33,395.

[304] EPA, Office of Air and Radiation, Technical Support Document, Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents (Nov. 2014), https://archive.epa.gov/epa/sites/production/files/2014-11/documents/20141106tsd-rate-to-mass.pdf.

[305] EPA, Clean Power Plan Toolbox, Clean Power Plan State-Specific Fact Sheets, https://archive.epa.gov/epa/cleanpowerplantoolbox/clean-power-plan-state-specific-fact-sheets.html.

that the goals were "designed to be met as part of the grid and over time, reflecting the inherent flexibility in the way the power system operates and the variety of ways in which the electricity system can deliver a broad range of opportunities for compliance for power plants and states."[306] EPA should follow a similar approach here and convert its presumptively approvable emission rates for affected sources into presumptively approvable mass-based emission rates (e.g., tons of CO_2 per year) regardless of whether it ultimately issues a model trading rule.

Expressing the emission limit as a mass-based rate has numerous advantages. First, it makes it easier for states to incorporate flexible compliance mechanisms such as emissions averaging or cap-and-trade programs into their state plans. Several states already have carbon trading programs with mass-based caps,[307] and the ability of those states to incorporate those programs into a trading program designed under section 111(d) would be beneficial. Additionally, EGUs have a lot of experience and familiarity with cap-and-trade programs (such as the Acid Rain Program and the Cross-State Air Pollution Rule) that are mass-based. Staying with an approach that is proven and with which EGUs have significant experience makes sense.

Second, it eases reliability concerns because older, less efficient fossil fuel-fired EGUs that are rarely used can be available for use when needed (i.e., in times of extreme heat or cold) when the grid is strained. For example, if a unit's emission limit is expressed as tons per year, these types of units can run for short periods of time as needed to ease the strain on the grid without fear of violating a short-term rate-based limit.

---

[306] *Id.*

[307] *See, e.g.*, Regional Greenhouse Gas Initiative, https://www.rggi.org/ (CO_2 cap-and-trade in the eastern portion of the United States covering EGUs in 14 states); California Cap-and-Trade Program, https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program (CO_2 cap-and-trade program in California that covers EGUs and other industries).

Third, because the GHG emission rate at units tends to increase over time as the unit ages, expressing the emission limitation as tons per year allows the unit to continue to operate. The unit may need to operate less over the course of a year but would not have to cease operation (which could happen under a rate-based approach).

PGen urges EPA to assist states and to convert its presumptively approvable emission rates for affected EGUs into presumptively approvable mass-based emission rates (e.g., tons of CO_2 per year).

In conclusion, PGen recommends EPA develop and issue a model trading rule that states can opt into for their state plans. This approach has many benefits: (1) it aids the states in developing approvable state plans; (2) it provides much needed flexibility to owners and operators to comply with the Proposed Rules and continue to provide reliable and affordable electricity; and (3) it would provide significant benefits to environmental justice communities, as discussed further in Section X. In developing this model rule, EPA should not unduly restrict trading so that owners and operators have maximum compliance flexibility, which in turn leads to maximum emission reductions and reduced costs. Finally, regardless of whether EPA issues a model trading rule, EPA should convert its presumptively approvable emission limitations from rate-based standards (lb CO_2/MWh) into mass-based standards (tons CO_2/year).

X. EPA's Environmental Justice Analysis Should Examine the Effects on Environmental Justice Communities of Decreased Electric Reliability and Lack of Access to Affordable Electricity.

As part of its development of the Proposed Rules, EPA examined the impact of the rulemaking in terms of air pollution effects on environmental justice ("EJ") communities.[308] EPA analyzed the impacts of the Proposed Rules on climate change, which it says will disproportionately

[308] 88 Fed. Reg. at 33,413.

affect EJ communities, and analyzed the Proposed Rules' effect on "other health-harming air pollutants from EGUs."[309] EPA generally found that emission reductions will be small and broadly distributed across all demographic groups.[310] In addition to analyzing those impacts, however, EPA must examine the impacts of costly regulations on EJ communities and how the Proposed Rules will affect those communities' access to affordable electricity. In particular, there is a clear and unique potential for harm to EJ communities that could flow from rules that do not adequately protect electric reliability. EPA also needs to acknowledge that flexible compliance measures such as emissions averaging and trading that states may adopt (and that EPA may develop as part of a model trading rule for the Proposed Rules) have been shown to further environmental benefits in environmental justice communities. Finally, the preamble to the Proposed Rules notes concerns that EJ advocacy organizations expressed during the pre-proposal phase of these proceedings. EPA has not, however, adequately responded to those concerns. Each of these items is discussed further below.

A. Electricity Prices and Energy Security

As the EIA explains, "[e]lectricity prices generally reflect the cost to build, finance, maintain, and operate power plants and the electricity grid."[311] Power plants costs, which include financing, construction, maintenance, and operating costs, are one of the key factors affecting electricity prices. Costs associated with emissions controls are included among these power plant costs and can be significant. Increases in electricity prices disproportionately impact EJ communities, which already pay a significant percentage of their income toward energy costs and force economic trade-offs that

[309] *Id.* at 33,247.

[310] *Id.*

[311] U.S. Energy Information Administration, *Electricity explained: Factors affecting electricity prices*, https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php (emphasis removed).

further imperil energy security in these communities.[312] The increases in electricity prices that will result from the Proposed Rules will only exacerbate this impact and cause additional hardship to lower income (EJ) communities.

Regardless of the specific rules governing electric markets, electric rates are set to recover the cost of delivering electricity. Accordingly, the additional costs associated with the Proposed Rules will be passed through to electric ratepayers. As explained in the RIA for this rulemaking, EPA projects that average retail electricity prices at both the national and regional level will experience the largest impacts in 2030, rising by 2 percent above baseline levels in that year.[313] In 2035, EPA projects that the Proposed Rules will result in a 0.24 percent increase in national average retail electricity price.[314] In 2024, EPA projects a 0.08 percent increase in national average retail electricity price.[315] In reality, these figures are much higher because EPA has overestimated the benefits of the IRA in the baseline (as discussed in Section XI) and underestimated the cost of CCS and co-firing hydrogen (as discussed in Sections IV.B and IV.C, respectively).[316]

A better and more realistic analysis of what the actual impact on electricity prices may be comes from EPA's evaluation of the Clean Power Plan. There, EPA concluded that the emission controls and compliance costs associated with that rule would result in annual costs ranging from

---

[312] U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool.

[313] RIA at 3-28.

[314] *Id.*

[315] *Id.* at 3-29.

[316] As discussed in those sections, EPA's reliance on the IRA as the means by which the Proposed Rules become cost-effective is misplaced. There is no guarantee that all (or, indeed, any) of the projects that would be needed to comply with the Proposed Rules would receive funding under the IRA. EPA has also substantially underestimated the cost of the Proposed Rules by adopting a base case that assumes an unrealistic impact of the IRA on coal-fired EGU retirements by 2030. *See infra* Section XI.

$5.5 billion and $7.5 billion in 2020 to between $7.3 billion and $8.8 billion in 2030.[317] EPA concluded that those costs would lead to "a [four] to [seven] percent increase in retail electricity prices, on average, across the contiguous U.S. in 2020."[318]

The costs of new environmental regulation are likely to fall disproportionally on lower-income households and EJ communities. Lower-income families are more vulnerable to energy costs than higher-income families because energy represents a larger portion of their household budgets. Increased energy costs mean that these households will have less income to spend on other necessities, like food, housing, childcare, and health care. As explained by the National Conference of State Legislatures, studies have shown that EJ communities and low-income families pay a significantly higher share of their income in energy costs.[319] Data from DOE's Low-Income Energy Affordability Data ("LEAD") Tool show that, on average, low-income households pay approximately 9 percent of their income in energy costs, which is three times more than non-low-income households.[320] The American Council for an Energy-Efficient Economy estimates that 25 percent of households have a "high energy burden," defined as above 6 percent of household

[317] 79 Fed. Reg. 34,830, 34,934-35 (June 18, 2014) (proposed Clean Power Plan).

[318] *Id.* at 34,948. Testimony at an April 14, 2015 congressional hearing confirmed that the Clean Power Plan, like any other environmental rule with significant compliance costs, would substantially increase electricity costs for ratepayers. One energy economist estimated that rates in thirty-one states could be fifteen percent higher each year than they would have been in the absence of the rule. House of Representatives, Report No. 114–171 at 10 (June 19, 2015), https://www.congress.gov/114/crpt/hrpt171/CRPT-114hrpt171.pdf. State officials similarly testified that the proposed Clean Power Plan could result in "potential increases of [twenty-two to fifty percent] in Florida, and between ten and thirty percent in Kansas. *Id.* at 11.

[319] National Conference of State Legislatures, Energy Justice and the Energy Transition at 1 (2022), https://www.ncsl.org/energy/energy-justice-and-the-energy-transition.

[320] U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool.

income.[321] Black, Indigenous, and People of Color communities "often experience the highest energy burdens when compared to more affluent or white households."[322] These disproportionate energy burdens have significant and lasting negative consequences for those that are impacted: "high energy burdens are associated with inadequate housing conditions and have been found to affect physical and mental health, nutrition, and local economic development."[323] For all of these reasons, new regulations to address GHG emissions should take the energy burden on disadvantaged communities into account.

B. Reliability

The Proposed Rules acknowledge that compliance flexibility is key to preserving electric reliability.[324] EPA should further acknowledge that compliance flexibility could benefit EJ communities. In particular, if states adopt plans that do not have adequate compliance flexibility, this could result in electric reliability problems, which are most likely to be borne disproportionately by EJ communities. Indeed, this provides yet another reason why EPA should develop a model trading rule for states to be able to adopt easily, as discussed in Section IX. If states do not adopt flexible compliance mechanisms and reliability problems ensue, industrial customers and customers with financial means will likely install emergency backup generation to manage their electric reliability concerns. These emergency backup units are typically uncontrolled, and frequent use of them could result in worse air quality where they are located, including in already disadvantaged communities located near industry. Residents of disadvantaged communities, on the other hand, will

[321] American Council for an Energy-Efficient Economy, How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden across the United States (Sept. 2020), https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.

[322] *Id.* at 2.

[323] *Id.* at 5.

[324] 88 Fed. Reg. at 33,415.

not have the means to be able to install emergency backup generation and will suffer the consequences of any electric service disruptions.

These issues raise concerns regarding "energy justice." The concept of energy justice "is based on the principle that all people should have a reliable, safe, and affordable source of energy."[325] A regulatory system that allows wealthy and privileged communities to avoid electric reliability problems and that would leave EJ communities without a similar remedy would violate environmental and energy justice principles. A flexible cap-and-trade compliance mechanism will likely provide the most efficient and best tested regulatory approach for allowing utilities to ensure electric reliability and will protect EJ communities in the process.

The need for compliance flexibility to protect reliability and to minimize costs to ratepayers is especially important for EJ communities because utilities serving those communities and those with facilities located in disadvantaged areas are often among the smallest electric generating companies and organizations. Electric cooperatives, for instance, are generally among the smallest utilities. According to the National Rural Electric Cooperative Association, electric cooperatives "serve 42 million people, including 92% of persistent poverty counties."[326] Community-owned public power utilities also serve a significant proportion of EJ communities and include many smaller generators.[327] Further, an analysis by the American Council for an Energy Efficient Economy found that areas served by investor-owned utilities, including in some of the nation's

---

[325] Aladdine Joroff, *Energy Justice: What It Means and How to Integrate It Into State Regulation of Electricity Markets* at 1 (Nov. 2017), https://elpnet.org/sites/default/files/2020-04/energy_justice_-_what_it_means_and_how_to_integrate_it_into_state_regulation_of_electricity_markets.pdf.

[326] National Rural Electric Cooperative Association, Electric Co-op Facts & Figures (Apr. 28, 2022), https://www.electric.coop/electric-cooperative-fact-sheet.

[327] American Public Power Association, 2022 Public Power Statistical Report, https://www.publicpower.org/system/files/documents/2022%20Public%20Power%20Statistical%20Report.pdf.

largest cities, include customers who face significant energy burdens and that utilities needed significant assistance to better serve these communities.[328] All of these constraints, especially for smaller utilities with limited generation assets, result in decreased options for reducing the costs and impacts of any significant new regulatory program on underserved communities. Flexible compliance mechanisms, like allowance trading, can help to alleviate these problems. For these reasons, EPA should develop a model trading rule so that states can more easily adopt these flexibilities into their state plans.

C. Cap-and-Trade Evaluations

Allowing affected EGUs to comply with the Proposed Rules through an emissions allowance trading program is likely the most direct and legally sound approach for providing the necessary compliance flexibility. It is also clear from recent evaluations of cap-and-trade policies that providing for compliance through allowance trading is unlikely to have negative environmental justice impacts and, in fact, should achieve the opposite.

The California Air Resources Board ("CARB") has, for instance, supported its Carbon Cap-and Trade Program with significant analysis of environmental justice issues. Based on the results of several studies, CARB has concluded that "[t]here is no evidence that the Cap-and-Trade Program has exacerbated local air pollution in environmental justice communities."[329] On the contrary, CARB explains that a 2020 study from the University of California, Santa Barbara found that air quality in EJ communities with large cap-and-trade facilities improved more than air quality in wealthier

[328] A. Drehobl and L. Ross, American Council for an Energy-Efficient Economy, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities at 25-29 (Apr. 2016), https://www.aceee.org/sites/default/files/publications/researchreports/u1602.pdf.

[329] CARB, FAQ Cap-and-Trade Program, https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program.

neighborhoods since the state began implementing the Cap-and-Trade Program.[330] That result was confirmed by a 2022 study by the California Office of Environmental Health and Hazard Assessment, which found that "the greatest beneficiaries of reduced emissions from facilities subject to the Cap-and-Trade Program have been disadvantaged communities and communities of color in California."[331]

CARB also makes clear that one of the most effective policy options to address EJ issues is to reduce GHG emissions through allowance trading while addressing local air pollution issues affecting EJ communities using existing legal authorities specifically designed to address localized air quality pollution.[332] This is a reasonable approach to these issues, given that the purpose of the Cap-and-Trade Program is reduction of GHGs, which have no significant localized air quality effect and no direct, exposure-based impact on disadvantaged communities.

EPA itself similarly concluded that an emission allowance cap-and-trade program will not adversely affect EJ communities in its Good Neighbor Plan for the 2015 national ambient air quality standards for ozone.[333] The Good Neighbor Plan is based in significant part on an ozone season emission trading program for NOx emissions from EGUs. The final rule also includes one of EPA's first and most extensive assessments of the EJ impacts of a major regulatory program since the adoption of the Biden administration's new policies on promoting EJ and ensuring that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and

[330] *Id.*

[331] *Id.*

[332] *Id.*

[333] 88 Fed. Reg. 36,654 (June 5, 2023).

commercial operations or programs and policies."[334] To evaluate potential EJ concerns, EPA performed two types of analyses: proximity analyses and exposure analyses.[335] The analyses were intended to determine baseline EJ impacts and potential EJ concerns "after implementation of the regulatory options under consideration" and "whether potential EJ concerns will be created or mitigated compared to the baseline."[336]

EPA's analyses resulted in the following findings: (1) "there likely are potential environmental justice concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory action for population groups of concern in the baseline"; (2) "disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to persist after implementation of the regulatory action or alternatives under consideration due to similar modeled concentration reductions across population demographics;" and (3) "[d]ue to the very small differences observed in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts across populations, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline." [337] Accordingly, even when the pollutant at issue does have a localized effect, which is not the case for CO_2, EPA has determined based on quantitative analysis that an emission allowance cap-and-trade program will not adversely affect EJ communities.

Based on California's and EPA's experiences, there is a strong basis for concluding that a regulatory program that adopts an emission allowance trading compliance mechanism will have environmental benefits for EJ communities and potentially reduce disproportionate impacts in addition to net impacts. Such a program could achieve that goal while avoiding negative

[334] *See id.* at 36,845.

[335] *Id.*

[336] *Id.*

[337] *Id.* at 36,845-46

consequences for disadvantaged communities that would result from increased electricity prices and loss of electric reliability in communities that already experience disproportionate energy burdens. For these reasons, EPA should make adoption of flexible compliance methods such as cap-and-trade or emissions averaging as easy as possible for states to accomplish and should prepare a model trading rule that states may choose to adopt. This approach will help ease the burden on disadvantaged communities.

D. Safety

The Proposed Rules acknowledge that a number of EJ organizations "raised strongly held concerns about the potential health, environmental, and safety impacts of CCS."[338] EPA's response to these concerns is simply that the Agency "believes that deployment of CCS can take place in a manner that is protective of public health, safety, and the environment, and should include early and meaningful engagement with affected communities and the public."[339] EPA goes on to note that there are several regulatory programs that may apply to CCS operations.[340]

EPA's response to these concerns does not give adequate consideration to the issues EJ advocates have raised, nor does it fulfill EPA's obligation to meaningfully engage with stakeholders as part of the EJ process. EPA should evaluate what issues the existing regulatory structure addresses, how effective the current regulatory regime may be, and which issues remain unregulated and potentially of concern. Noting that regulations exist without examining what those rules achieve and where regulatory gaps remain does not fully address the issues that concern EJ communities. Given the high priority EPA has placed on EJ issues, a more complete discussion of these issues is especially warranted.

---

[338] 88 Fed. Reg. at 33,247.

[339] *Id.*

[340] *Id.* at 33,247-48.

XI. EPA's IPM Analysis on Which the Proposed Rules Rely Is Deeply Flawed.

IPM is EPA's principal modeling tool for evaluating the economic and compliance impacts of its rules on the electric power sector. In this rulemaking, EPA evaluated two modeling scenarios: (i) Pre-IRA 2022 Reference Case (January 2023); and (ii) Post-IRA 2022 Reference Case (March 2023). The Pre-IRA 2022 Reference Case was used in modeling the compliance and economic impact of the proposed ELG rule, which was published on March 29, 2023, while the Post-IRA 2022 Reference Case, which is the Updated Baseline, was used in modeling the economic and compliance impacts of the proposed Mercury and Air Toxics Standards Residual Risk and Technology Review and the Proposed Rules. Both IPM reference cases use the EIA's Annual Energy Outlook (AEO) 2021 to forecast future electrical demand.[341]

The aspects of the Proposed Rules that EPA evaluated in its IPM runs are fundamental to a rulemaking under Section 111 of the Clean Air Act—economic impact (i.e., costs), impact of the rule on the energy mix and the reliability of the power grid, etc. Flawed IPM modeling and analysis means that EPA has failed to consider or properly analyze an "important aspect of the problem."[342]

EPA's post-IRA IPM model run is the "base case" from which the impacts of the Proposed Rules are evaluated. EPA's base case, however, contains unrealistic and wildly optimistic assumptions about the impact of the IRA on coal retirements and CCS retrofits, as well as the amount of renewables that would replace the retired generation. As a result, the impact of the Proposed Rules is grossly underestimated.

---

[341] Additional information and references for IPM and its use in this rulemaking is provided in J. Marchetti, Technical Comments on the U.S. Environmental Protection Agency's Integrated Planning Model's Evaluation of the Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants – Proposed Rule (Aug. 7, 2023) ("Marchetti IPM Report") (Attachment M to these comments).

[342] *State Farm*, 463 U.S. at 43.

A. EPA's Base Case Is an Outlier, Inconsistent with Every Other Available Model, Including That Published by the EIA.

Comparison of the results of EPA's post-IRA IPM to the EIA's 2023 Annual Energy Outlook ("AEO23"), the National Renewable Energy Laboratory's Regional Energy Deployment System ("ReEDS"), EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy ("REGEN") model, and Resources for the Future's Haiku model shows that IPM's base case is an unrealistic outlier.[343] Most notably, all of these other models forecast coal capacity in their Base/Reference Case to be in excess of 100 GW in 2030, except IPM, which projects 69 GW of coal in 2030. In other words, IPM's flawed assumptions result in well more than 31 GW of coal retirements than any other model, without even accounting for the Proposed Rules.[344] This has the effect of greatly underestimating the impact of the Proposed Rules on coal-fired units.

The level of renewable capacity that IPM projects in its Base/Reference Case is significantly less than what is projected by the other models. Given the level of coal capacity IPM "retires" in its Base/Reference Case, one would expect a greater amount of renewable/storage capacity to be installed, especially in 2028 and 2030. Yet, the data show the exact opposite. The problem, it turns out, is that EPA's IPM model assumes an unrealistically low renewables/storage-to-coal replacement ratio. For example, AEO23 has more than 20 times more renewable/storage capacity replacing one MW of retired coal, while ReEDS has anywhere from 15 to 20 times more renewable/storage capacity replacing one MW of retired coal. The IPM base case assumes a replacement ratio of less than 2 (1.8 and 1.4 for the years 2030 and 2028, respectively).[345]

[343] Marchetti IPM Report, at 3-10.

[344] *Id.* at 6-7.

[345] *Id.* at 7-9.

The renewables/storage-to-coal replacement ratio is an important consideration because renewable generation is "non-dispatchable"—i.e., it is not always available and thus cannot be dispatched at full, installed capacity whenever needed because renewable generation is dependent on uncontrollable factors such as the amount of sunshine or wind; while coal and gas generation is dispatchable—i.e., it is always available at full, installed capacity.[346] Accordingly, to maintain reliability, it takes multiple MWs of installed capacity of a renewable resource to replace 1 MW of retired dispatchable capacity.

That the IPM model uses a woefully inadequate renewables/storage-to-coal replacement ratio is further evidence of how unrealistic IPM's base case is. It also has a significant impact on reliability of the electric grid: If as much coal as EPA assumes would be retired does in fact retire as projected, and there are not enough other generation resources to replace it, the reliability of the grid would be severely affected. EPA nowhere considers this.

B. IPM's Updated Baseline Does Not Consider Key Challenges Facing the Power Sector's Transition from Dispatchable Fossil Generation to Renewables.

EPA's IPM Updated Baseline modeling, in particular for 2030, fails to consider grid reliability issues confronting the electric power sector. As mentioned above, EPA in its IPM modeling replaces dispatchable power with non-dispatchable renewable generation without any consideration of the different nature of these two types of generating assets.[347] Nor does EPA consider factors relating to capacity in queues, length of time in the queues, and project completion of renewables.

As the Marchetti IPM Report explains:

---

[346] *See supra* note 10.

[347] *See also* Marchetti IPM Report at 14-15 (discussing the importance of "accredited capacity" for renewables and EPA's failure to consider it in its IPM modeling).

> The queue for electric generating resources represents the time a project developer initiates an interconnection request and thereby enters the queue, which is followed by a series of interconnection studies. The studies culminate in an interconnection agreement, which is a contract between the RTO or utility. After this interconnection agreement, the project still must be built; however, most proposed projects are withdrawn during the interconnection study process.[348]

Currently, across the United States, the queues are primarily composed of renewable generation. Only a very small percentage of the projects in the queues are actually built, however. For example, PJM has a historic completion rate (queue to steel in the ground) of 5 percent. "A major factor that is impacting these completion rates are the various interconnection costs associated with renewable generation which have exploded over the past years suggesting limited transmission availability."[349] There is no discussion by EPA, whether in the documentation for its IPM runs or elsewhere in the docket, of interconnection queues or project interconnection rates. This is a substantial flaw in EPA's analysis of the Proposed Rules.

EPA simply does not consider in its IPM modeling the serious reliability concerns already facing the power industry. Indeed, even in the recent past, several RTOs have taken action to delay announced coal generation retirements because of these reliability concerns. These concerns are bound to increase, as more coal retirements are projected. Yet, EPA's unrealistic assumptions project a large amount of retirements by 2030. As the Marchetti IPM Report details, "EPA simply assumes the IRA's financial provisions will alleviate all the uncertainties the power industry will face during this transition period. These assumptions dismiss concerns regarding supply chain problems,

[348] *Id.* at 12.

[349] *Id.* at 14.

siting, labor shortages, and—most importantly—transmission and other infrastructure needed to support renewables."[350]

In truth, EPA cannot seriously consider reliability issues in IPM, except through the assumptions and constraints it builds into the model (which EPA has clearly not done here). Instead of truly evaluating the reliability implications of its assumptions (and its Proposed Rules), EPA's model (IPM) instantaneously "builds" new resources, without considering the many issues listed above that grid generators and operators are facing.[351] Moreover, at most, IPM is a "resource adequacy" model; it does not evaluate reliability in and of itself. And, as EPA concedes, "resource adequacy … is necessary (but not sufficient) for grid reliability."[352] Yet, the only tool EPA claims to have used to assess the impact of the Proposed Rules on reliability is its IPM model runs (with and without the Proposed Rules). That is an arbitrary and capricious failure to address one of the most important aspects of the problem in this rulemaking.

C. EPA's 2030 "Base Case" Unrealistically Includes Significant Deployment of CCS at Coal-Fired EGUs, Inexplicably Retires Units that are Not Slated for Retirement by 2030, and Contains Other Errors.

EPA's IPM "base case" projects CCS would be used by 2030 at 27 coal-fired units (about 9 GW of capacity). Even assuming that CCS were technically feasible at these units, there is simply not

[350] *Id.* at 11; *see also* Weeda Report at 2 ("Shutting down existing fossil fuel resources, driven by compliance requirements of the EPA's proposed rule, would result in a massive need for renewable energy. This generation is geographically distributed and weather dependent, requiring the need for massive investment in transmission infrastructure and affecting the economics associated with investing in alternative technologies in an effort to keep the electric grid functional and reliable. These investments are expected to amount to trillions of dollars per region of the country and involve huge construction, putting unprecedented demand on labor and materials."); *id.* at 5-7 (discussing transmission issues for large amounts of renewables needed to maintain resource adequacy).

[351] Marchetti IPM Report at 16.

[352] EPA Office of Air and Radiation, Resource Adequacy Analysis Technical Support Document at 3 (April 2023).

enough time for CCS to be deployed in less than 7 years from the proposal (6 years from the final rule).[353]

The 2028 IPM modeling run retired 108 coal units (51.4 GW) from 2023 to 2028. In the 2030 analysis, IPM retired an additional 58 coal units (28.5 GW). The total number of retirements for the two modeling run years is 166 coal units (79.9 GW).[354] This is incorrect, however, for at least 41 coal units (18.1 GW) that have no plans and are unlikely to retire by 2028 and an additional 25 coal units (15.GW) that have no plans and are unlikely to retire by 2030.[355] There are other errors in the modeling runs for projected coal-to-gas conversions, units that would retire by 2035 and operate at less than 20 percent capacity factor starting in 2030, and individual units that are "projected" to follow an illogical pattern (for example, one unit is projected to retire in the proposal run for the year in which it is projected to retrofit with CCS in the base case; another unit is projected to retire in 2028 but is nonetheless modeled as existing in the 2030 base case run; etc.).[356]

In short, EPA's IPM projections are contradicted by the empirical evidence before the Agency, are replete with unreasonable assumptions, and contain substantial errors. The Agency's reliance on these flawed runs is arbitrary and capricious.

XII. EPA Failed to Provide Sufficient Time for Public Comment on the Proposed Rules, in Violation of the CAA and the Administrative Procedure Act.

Courts have said that Congress intended the Administrative Procedure Act's requirement to provide notice and comment (which is mirrored in section 307(d) of the CAA) "(1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to

[353] *See* Section V (discussing timeline for CCS projects).

[354] Marchetti IPM Report at 19.

[355] *Id.*

[356] *Id.* at 19-22.

support their objections to the rule and thereby enhance the quality of judicial review."[357] The comment period for the Proposed Rules does not meet this legal standard because it fails to provide for meaningful public participation—even with the additional 15-day extension that EPA provided.

First, EPA ignored the requests from numerous affected parties for additional time, including three letters from PGen,[358] expressing concern that the comment period failed to provide the time needed for the public to provide meaningful input on the Proposed Rules. These requests have been submitted by parties whose input is critical to the Proposed Rules, including requests from state environmental agencies[359] and the ISO/RTO Council[360] (which is charged with ensuring the reliability of the electric generating system). These letters overwhelmingly requested that EPA provide 60 additional days for comment.

---

[357] *Prometheus Radio Project v. FCC*, 652 F.3d 431, 449 (3d Cir. 2011); *accord Idaho Farm Bureau Fed'n v. Babbitt*, 58 F.3d 1392, 1404 (9th Cir. 1995) ("The purpose of the notice and comment requirement is to provide for meaningful public participation in the rule-making process.").

[358] Letter from A. Wood, Counsel to PGen, to M. Regan (May 23, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0041; Letter from A. Wood, Counsel to PGen, to M. Regan (June 30, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0165; Letter from A. Wood, Counsel to PGen, to M. Regan (July 24, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0248.

[359] *See, e.g.*, Letter from E.E. Chancellor, Interim Executive Director, Texas Commission on Environmental Quality, to EPA (June 5, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0095; Comment of the Oklahoma Department of Environmental Quality (June 1, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0076; Letter from D. Czecholinski, Air Quality Division Director, Arizona Department of Environmental Quality, to EPA (May 23, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0064; Letter from M. Kennedy, Director, Division for Air Quality, Kentucky Energy and Environment Cabinet, Department for Environmental Protection, to EPA (May 31, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0071.

[360] Comment of the ISO/RTO Council (June 8, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0092. The ISO/RTO Council consists of: ISO New England Inc.; PJM Interconnection, L.L.C.; California Independent System Operator Corporation; New York Independent System Operator, Inc.; Midcontinent Independent System Operator, Inc.; Southwest Power Pool, Inc.; and the Electric Reliability Council of Texas, Inc. These groups asked for a 60-day extension in order to have "adequate time to evaluate the Proposed Rule and consider providing input to address any concerns with bulk power grid reliability," *id.* at 1, because "[t]he evaluation of potential reliability impacts … cannot be completed under the current comment time frame," *id.* at 2.

Once EPA announced it was extending the comment period by an additional 15-days, many more letters were sent to the Agency (including two from PGen) explaining that the short extension did not solve the problem.[361] Importantly, these are not the only letters that EPA has received. PGen is aware of several other similar requests that are not in the rulemaking docket.

In addition, members of Congress have expressed concern that the comment period was insufficient. In a letter to EPA dated June 6, 2023, the Chair of the House Energy and Commerce Committee Cathy McMorris Rodgers and other members of the Committee expressed "disappoint[ment] that you declined the Committee's request to provide the public a reasonable period to respond to the Proposal. Considering its unprecedented technical and legal complexity, and EPA's past precedent on similar, less complex rulemakings, we ask that you extend the Proposal's comment period to at least 120 days."[362] Similarly, the Ranking Member of the Senate Environment and Public Works Committee Shelley Moore Capito and other members of the Committee wrote EPA a letter on June 8, 2023, "to express serious concerns with the limited opportunities for public engagement in the rulemaking process for the" Proposed Rules. In a call with reporters after EPA provided the 15-day extension of time, she said she is "concerned that the

[361] *See, e.g.*, Letter from R. Hodanbosi, Chief, Division of Air Pollution Control, Ohio Environmental Protection Agency, to M. Regan, Administrator, EPA (June 15, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0123; Letter from M. Durbin, President, Global Energy Institute and Senior Vice President, Policy, U.S. Chamber of Commerce, to M. Regan, Administrator, EPA (July 13, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0169 (second letter); Letter from J.E. Sloan, Executive Director, The Association of Air Pollution Control Agencies, to J. Goffman, Principal Deputy Assistant Administrator, EPA (June 30, 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0164 (second letter).

[362] Letter from C.M. Rodgers, Chair, House Committee on Energy and Commerce, et al., to M. Regan, Administrator, EPA at 1 (June 6, 2023), https://d1dth6e84htgma.cloudfront.net/06_06_23_Letter_to_Administrator_Regan_on_Powerplant_Rules_Comment_Extension_09613a1b3c.pdf?updated_at=2023-06-06T13:34:55.988Z.

EPA could only give us another 15 days…. [W]e asked for measurably more."[363] And the Chair of the House Energy and Commerce Committee Cathy McMorris Rodgers and the Chair of that Committee's Subcommittee on Environment, Manufacturing, and Critical Materials Bill Johnson followed up with EPA in a letter written on July 31, 2023, to state that the decision to extend the comment period by only "a mere 15 days, inclusive of two weekends … raises serious concerns about your adherence to your Clean Air Act and Administrative Procedure Act responsibilities."[364]

Most egregiously, on July 7, 2023, EPA posted a 32-page memorandum to the docket entitled "Integrated Proposal Modeling and Updated Baseline Analysis."[365] This document was accompanied by 22 attachments and four new IPM model run outputs, with each model run containing 18 separate Microsoft Excel spreadsheet outputs totaling 129 megabytes of data. These new data were released with a mere 21 business days left in the comment period and materially changed EPA's original analysis of the Proposed Rules.

Importantly, the comment period of 120 days that was the overwhelming request of parties seeking an extension was *less* time than EPA has previously provided for comments on similar rules. Five separate rules encompass the Proposed Rules, and all of them build on previous rulemakings where EPA promulgated the rules in smaller rulemaking packages *and* allowed for more time even though there was less material on which to comment. For example, when EPA proposed the NSPS

---

[363] Curtis Tate, West Virginia Public Broadcasting, *Capito: EPA's New Comment Period On Power Plant Rules Not Enough*, https://www.wvpublic.org/capito-epas-new-comment-period-on-power-plant-rules-not-enough/.

[364] Letter from C.M. Rodgers, Chair, House Committee on Energy and Commerce, and B. Johnson, Chair, Subcommittee on Environment, Manufacturing, and Critical Materials, to M. Regan, Administrator, EPA at 1 (July 31, 2023), https://d1dth6e84htgma.cloudfront.net/07_31_23_Letter_to_Regan_re_EPA_Powerplant_NSPS_2nd_Extention_Request_643548c6a1.pdf.

[365] EPA, Office of Air and Radiation, Integrated Proposal Modeling and Updated Baseline Analysis: Memo to the Docket (July 7, 2023), https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf.

for new fossil fuel-fired EGUs in 2014, the Agency gave the public 120 days to file comments on the proposed rule. When it proposed emission guidelines for existing fossil fuel-fired EGUs later that year, it provided the public with 165 days to file comment. When the Agency proposed the Affordable Clean Energy Rule and the repeal of the Clean Power Plan (two prior emission guidelines for existing fossil fuel-fired EGUs), it provided 192 days for comment. PGen's request for 120 days is eminently reasonable in comparison—especially considering that all of these prior rules are fractions of the current rulemaking package.

Moreover, EPA is not subject to any deadlines that necessitated having a shortened comment period. There is no valid reason for EPA to have provided a truncated comment period here. The Agency is not subject to any court order or consent decree that requires it to act by any date. EPA began the process for reviewing and proposing revisions to the NSPS within the eight-year statutory deadline, and the Clean Air Act does not contain any deadline by which emission guidelines must be promulgated.

The complexity of the Proposed Rules is illustrated by the fact that EPA took over two years to work on them. When President Biden took office on January 20, 2021, he immediately directed EPA to reconsider and reverse the prior administration's rulemakings regarding greenhouse gas emissions from the electric power sector. After taking 841 days to release a signed pre-publication version of the Proposed Rules (and then releasing the proposed regulatory text and several key technical documents later—including new IPM modeling data nearly two months later), it was unreasonable to expect the public to be able to digest this information in 77 days (or less in the case of the IPM modeling data and other technical documents) and provide EPA with meaningful comments.

EPA's failure to provide sufficient time for interested and affected parties to provide meaningful comment violated the Administrative Procedure Act and the CAA.

XIII. Additional Items Needing Clarification or Changes

PGen would like to highlight a few additional areas in the Proposed Rules in which clarification or minor changes are needed. These areas are:

***Definition of "Electric Generating Capacity"*:** Clarification is needed regarding the definition of "electric generating capacity." The proposed emission guidelines set a threshold for natural gas-fired stationary turbines "with an electric generating capacity equal to or less than 300 MW."[366] The term "electric generating capacity" is not defined, and it could mean several things (e.g., nameplate capacity, maximum capacity as ISO condition, maximum capacity at any ambient condition). Even with EPA's recent release of the Applicability Memo, which focused on the apportioning of steam turbine capacities on combined cycle units and attempted to provide assistance on this issue, there is a lot of confusion on this point, and EPA should clarify exactly what "electric generating capacity" means and how it is calculated.

***Calculation of Electric Generating Capacity at Combined Cycle Units*:** EPA's Applicability Memo explains how steam turbine capacities on combined cycle units should be apportioned. PGen requests that EPA consider eliminating the concept of HRSG apportionment in the Proposed Rules because it is a bad policy to penalize combined cycle units that utilize recovered waste heat only to augment the output of the gas-fired turbine. The steam produced by the HRSG does not cause CO_2 emissions. As currently written, EPA's Proposed Rules may encourage owners and operators of EGUs to consider multiple simple cycle units as a solution to staying below the 300 MW threshold, which could have the effect of increasing CO_2 emissions.

***Increments of Progress*:** As currently drafted, the Proposed Rules require the owners and operators of certain existing sources to begin work on increments of progress before a state plan has

[366] Proposed 40 C.F.R. § 60.5850b(a).

been approved by EPA.[367] These increments of progress include things such as the awarding of contracts.[368] Owners and operators should not have to legally bind themselves in contracts when it remains unclear whether the state plan will be approved. EPA should revise the proposed regulatory text so that the timing to complete increments of progress begins to run after a state plan has been approved by EPA.

***Carbon Pollution Standards for EGUs Websites*:** In the Proposed Rules, EPA proposes "that each State plan must require owners and operators of affected EGUs to establish publicly accessible websites, referred to … as a 'Carbon Pollution Standards for EGUs website,' to which all reporting and recordkeeping information for each affected EGU subject to the State plan would be posted."[369] This proposed requirement is burdensome, unnecessary, and inconsistent with the principles of the Paperwork Reduction Act, which states that "[w]ith respect to the collection of information and the control of paperwork, each agency shall ... certify (and provide a record supporting such certification, including public comments received by the agency) that each collection of information ... is not unnecessarily duplicative of information otherwise reasonably accessible to the agency."[370] EPA also has acknowledged in several instances that a central tenet of the Paperwork Reduction Act is to decrease redundancy and eliminate duplicity.[371] EPA's proposed

[367] *Id.* § 60.5740b(a)(4).

[368] *Id.* § 60.5740(a)(4)(ii).

[369] 88 Fed. Reg. at 33,400.

[370] 44 U.S.C. § 3506(c)(3)(B).

[371] *See, e.g.*, 81 Fed. Reg. 57,439, 57,440 (Aug. 23, 2016) ("Comments expressed concern about the duplication and overlap of existing rules created by the proposed rule.… The Agency has reviewed the comments and agrees that the inclusion of [certain] provisions in the proposed rule created repetition and overlap, so they have been removed."); 77 Fed. Reg. 66,432, 66,433 (Nov. 5, 2012) ("Modifying the survey to simultaneously collect information for multiple purposes will increase response rates, reduce duplicity in information collected by respondents, and add convenience to respondents."); 69 Fed. Reg. 57,910, 57,910 (Sept. 28, 2004) ("This action is undertaken to

website reporting requirement in the Proposed Rules appear to be inconsistent with the Paperwork Reduction Act's goal of avoiding unnecessarily duplicative procedural steps and requirements. As EPA notes, "this information will also be required to be submitted directly to the EPA and the relevant State regulatory authority."[372] This information is publicly available and sufficient. If EPA wants to make this information available on a website, then it should post the information itself.

* * *

PGen appreciates the opportunity to comment on EPA's Proposed Rules. If EPA has any questions on these comments, or if EPA would like to meet with PGen members to discuss these comments further, it should contact PGen's counsel below, who will work with PGen's Board of Directors to arrange a convenient time.

Dated: August 8, 2023

/s/ Allison D. Wood

Allison D. Wood
Makram B. Jaber
MCGUIREWOODS LLP
888 16th Street, N.W., Suite 500
Black Lives Matter Plaza
Washington, D.C. 20006
(202) 857-2420
awood@mcguirewoods.com

consolidate information requirements for the same industry into one [Information Collection Request], for simplification and to avoid duplicity.").

[372] 88 Fed. Reg. at 33,400.