

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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

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We submit these comments on behalf of Clean Air Task Force and Natural Resources Defense Council (together, “Commenters”) in response to the U.S. Environmental Protection Agency’s November 20, 2023 supplemental notice of proposed rulemaking in the above-captioned docket, 88 Fed. Reg. 80682. Commenters are nonprofit organizations with decades of legal, technical and policy expertise on energy, environmental, and public health issues.

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Table of Acronyms and Abbreviations

CAELP	Center for Applied Environmental Law and Policy
CATF	Clean Air Task Force
CCS	Carbon Capture and Storage
CO₂	Carbon Dioxide
COP28	28th Conference of the Parties to the United Nations Framework Convention on Climate Change
CPP	Clean Power Plan
CT	Combustion Turbine
DOE	Department of Energy
EDX	Energy Data eXchange
EGU	Electric Generating Unit
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FEED	Front-End Engineering and Design
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GHG	Greenhouse Gas
IIJA	Infrastructure Investment and Jobs Act of 2021
IPM	Integrated Planning Model
IRA	Inflation Reduction Act of 2022
IRP	Integrated Resource Plan
ISO	Independent System Operator
MATS	Mercury and Air Toxics Standards

[M/G]	[Mega/Giga] Watt
W	Megaton
Mt	Megawatt-hour
MWh	
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NRDC	Natural Resources Defense Council
NRECA	National Rural Electric Cooperative Association
PSF	Permanent School Fund
PUC	Public Utility Commission
RTO	Regional Transmission Organization
RULOF	Remaining Useful Life and Other Factors

I. Introduction

In May of this year, consistent with its statutory charge, the U.S. Environmental Protection Agency (EPA) issued a proposal to control climate-forcing carbon pollution from certain subcategories of fossil fuel-fired electric generating units (EGUs).¹ On November 20, 2023, EPA issued a supplemental notice of proposed rulemaking soliciting comments on “whether the Agency should include a specific mechanism ... to address grid reliability needs that may arise during implementation of its final rules.”²

Underlying market trends and the incentives in the Inflation Reduction Act (IRA) and other recent legislation are moving the power sector away from fossil fuel-fired generation toward cleaner options, and these trends will continue. These trends and incentives alone are not sufficient, however. It is imperative for EPA to issue standards as required by the Clean Air Act to protect public health and the environment, to secure and extend the emission reductions expected from current trends and incentives. EPA has a long history of fulfilling its environmental statutory mandate in the context of an evolving power sector without jeopardizing reliability. In fact, the extreme weather caused by climate change has been a major factor in many reliability events in recent years, in which fossil sources frequently proved to be the least effective at addressing shortfalls in electricity supply. These events cost the U.S. economy billions of dollars and caused hundreds of deaths. Fossil fuels exacerbate this climate change, making EPA’s rules even more important for long-term health, the environment, and electric reliability.

Since comments were submitted in August on EPA’s proposal, warnings about the dangers, pace and contributors to climate change have only become more dire. Last month, the U.S. Government issued its preeminent report on climate change impacts, risks and responses, the Fifth National Climate Assessment.³ The report finds that significant climate change is happening now in all regions of the country and that without deeper cuts to climate pollution the impacts will continue to grow. Climate-related extreme weather events pose a rapidly intensifying threat, costing the country at least \$150 billion each year and disproportionately affecting underserved and overburdened communities. Meanwhile, the UN Environmental Programme issued an even more blunt report: “Broken Record: Temperature hit new highs, yet

¹ New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33240 (proposed May 23, 2023) (to be codified at 40 C.F.R. pt. 60, subparts TTTT, TTTTa, UUUUb) [hereinafter Proposal].

² New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 80682, 80684 (Nov. 20, 2023).

³ Allison R. Crimmins et al., *Fifth National Climate Assessment*, U.S. Global Change Research Program (2023), <https://nca2023.globalchange.gov/>.

world fails to cut emission (again).”⁴ The report concludes that global greenhouse gas (GHG) emissions have set new records, exacerbating inequity, and that there has been insufficient movement on national commitments to reduce emissions as needed to avoid dangerous temperature increases and climate impacts.

At the recently-concluded 28th Conference of the Parties to the United Nations Framework Convention on Climate Change (COP28), the United States joined other nations in the assessment that greater and faster action is needed. As relevant to the power sector, the action agenda agreed to at the COP28 includes: (a) tripling global renewable energy capacity and doubling the global average annual rate of energy efficiency improvements by 2030; (b) accelerating the phase-down of unabated coal power; (c) accelerating movement towards net zero energy systems using zero- and low-carbon fuels well before 2050; (d) transitioning away from fossil fuels; and (e) accelerating deployment of zero- and low-emitting technologies.⁵

As described in EPA’s proposal, and Commenters’ August submission, fossil-fired EGUs are the largest industrial source of climate pollution in the U.S., and Clean Air Act Section 111 requires EPA to set emission limits for this source category commensurate with the best systems of control. The most stringent standards proposed are focused on the most polluting portion of the fleet – long-lived coal-fired EGUs and baseload gas-fired EGUs. But because the numbers of these units are in decline, and represent a small percentage of the total fossil fuel-fired fleet, the impacts on the electric sector from a final rule (even one that includes Commenters’ recommendations for improvements), will be modest and manageable. EPA carefully considered the diverse roles the sources covered by the proposal play in maintaining a reliable supply of electricity, created subcategories aligned with those roles, and proposed standards of performance and emission guidelines tailored to those circumstances.

The proposed subcategories and emission limits are keyed to the trends and trajectory of the sector. The proposal provides sufficient timelines and flexibilities to allow for state- and company-level planning, permitting, construction and infrastructure buildout. The proposed rule design ensures that the covered fossil fuel-fired EGUs are well controlled in a manner that will not interfere with reliable operation of the electric grid.

There are well-established and effective procedures, regulations, and enforceable standards in place to ensure the reliability of the U.S. power system. The power industry’s many stakeholders are well-organized and strongly oriented towards a safe and reliable operation of the system. The industry has a long history of complying with environmental standards while maintaining a resilient and reliable grid.

⁴ Anne Olhoff, et al., *Emissions Gap Report 2023*, United Nations Environment Programme (2023), <https://www.unep.org/resources/emissions-gap-report-2023>.

⁵ United Nations Framework Convention on Climate Change, *Outcome of the first global stocktake*, U.N. Doc. FCCC/PA/CMA/2023/L.17 (Dec. 13 2023), https://unfccc.int/sites/default/files/resource/cma2023_L17_adv.pdf.

Comments and discussions among stakeholders have identified two types of reliability concerns. The first type is exemplified by short-duration, unpredictable events such as winter storms, summer heat waves or other extreme weather. EPA's proposed rules are designed with a built-in mechanism for responding to short-duration generation increases that may be needed in such weather events. Specifically, the emission limits and capacity factor limits in the proposal are framed on an annual average basis. Should a plant be required to operate at a high capacity during a winter storm or summer heat wave, the annual average limit can still be readily met with minimal impact on the plant's operation the rest of the year.⁶ Thus, the annual averaging structure of the EPA proposed rules assures that the need to comply with EPA and state carbon limits will not compromise the ability to run various generation resources extra hard during such events.

The second type of reliability concern is the scenario where grid planners have expected the delivery of new resources – ranging from renewable generation to transmission to retrofit of existing plants with pollution controls – but the delivery of those resources is delayed for reasons outside of the regulated source's control. The design of the proposed rules will bring forth information lacking today that will help grid planners and operators to identify and head off any such resource adequacy problems earlier.

Our August comments described the ability to achieve emission reductions under Clean Air Act Section 111 while ensuring reliability.⁷ In this submission we supplement those comments with the following:

1. The power sector is changing significantly under business-as-usual irrespective of this rulemaking. EPA's projections about how it will change are reasonable, and even conservative. Existing trends away from the most polluting plants, reinforced by the IRA incentives, mean that the most stringent performance standards under this rule will apply to a small portion of the fleet. Experience demonstrates that transitions to a cleaner grid can be achieved reliably.
2. EPA's proposal, as well as Commenters' recommendations for improvements, are modestly incremental to the business-as-usual changes and are designed to accommodate reliability while reducing emissions.
 - a. The subcategories, long timelines, state plans with increments of progress, milestones, ability to consider remaining useful life and other factors (RULOF), and incorporate flexibilities, as well as revise plans, support reducing emissions while maintaining reliable electricity supply.
 - b. Commenters' modeling of the proposal demonstrates its incremental nature and compatibility with reliability even under extreme weather scenarios.

⁶ In addition, hours when a unit is called upon to operate during an emergency would effectively not be included in the calculation. *See* Proposal at 33333.

⁷ Comments of Clean Air Task Force, Natural Resources Defense Council & The Nature Conservancy, Docket ID No. EPA-HQ-OAR-2023-0072-0893, at Secs. IV, VIII (Aug. 8, 2023) [hereinafter Joint Comments].

3. Reliability institutions have the authority, tools, processes, and mechanisms in place to ensure electricity reliability, and they have the responsibility to refine and add to these procedures during the ongoing changes in the market, including the incremental additional changes associated with this proposal.
4. Any calls for reliability-based delays should be addressed through the Clean Air Act Section 111 variance provisions and EPA's recently issued implementation rules.
5. An appendix providing a case study of the similar framework, concerns, and results of the 2015 standards for new coal and gas-fired plants.
6. An appendix assessing the increments of progress and state plan revision framework for sources complying with the standards utilizing post-combustion capture, as well as an update on the improving ecosystem for carbon capture and storage (CCS) projects.

II. The power sector is evolving under business-as-usual.

The power sector has been undergoing significant change over the past twenty years, due to a combination of market forces and policy, all while maintaining reliable electricity. The sector made a dramatic shift from coal-fired power to gas-fired power in the 2010s and is now shifting towards renewable generation resources. The remaining coal fleet is aging and significant retirements are anticipated, renewable generation is making up a larger and larger portion of generation, and the role of gas is shifting to a quick-ramping resource to firm renewable generation. These trends are being accelerated by the IRA, state programs, and environmental and public health concerns, all of which are acting to spur this transition away from fossil fuels. EPA tailored the proposed standards to build on these trends, setting the power sector up for cost-effective compliance.

A. The power sector has undergone a dramatic transformation over the past two decades, without reliability issues arising.

The U.S. power grid has seen tremendous change in the last two decades. Twenty years ago, coal made up more than half of the U.S. electricity mix. Wind and solar power made up just 0.3 percent of the grid and, in total, renewables (mainly hydro) made up about 7.5 percent of the grid.⁸ Gas comprised about 17 percent of the electricity mix in 2003. Today, coal's share has fallen by more than two-thirds. The U.S. Energy Information Administration (EIA) estimates that coal will make up just 17 percent of the electricity mix this year, with gas providing 42 percent of electricity, followed by renewables at 22 percent (of which wind and solar now make up almost 70 percent of the renewable mix).⁹

This transformation occurred without significant or widespread reliability issues, even as EPA adopted and implemented several rules meaningfully limiting air pollution from power plants. In

⁸ U.S. Energy Information Administration (EIA), *Electricity Data*, Generation and thermal output: Net Generation, <https://www.eia.gov/electricity/data.php> (last visited December 13, 2023).

⁹ EIA, *Short-Term Energy Outlook* (Dec. 12, 2023), <https://www.eia.gov/outlooks/steo/>.

many of those rulemakings, opponents claimed that the limits would compromise reliability. As discussed below, and in the case study appended to these comments, contrary to those claims, EPA’s regulatory limits were readily met or surpassed without reliability problems.

In several of those rulemakings, EPA carefully designed narrow regulatory mechanisms to allow sources to delay or be temporarily exempted from compliance upon a showing of necessity to avoid a critical reliability issue—and those mechanisms were rarely needed. For example, in the Mercury and Air Toxics Standards (MATS), EPA delineated a process to give a one-year extension in the form of an administrative compliance order upon demonstration of a reliability issue.¹⁰ In the Clean Power Plan (CPP), EPA allowed short-term state plan modifications if a long-term reliability problem emerged without warning and outside owners’ and operators’ control.¹¹ The agency also provided a mechanism to account for abnormal variability in power sector operations in its cross-state ozone rules.¹² In each of these cases, use of the reliability mechanism did not prove to be widely needed.¹³

¹⁰ Memorandum from Cynthia Giles to Regional Administrators et al., Re: The Environmental Protection Agency’s Enforcement Response Policy for Use of Clean Air Act section 113(a) Administrative Orders in Relation to Electric Reliability and the Mercury and Air Toxic Standard (Dec. 16, 2011), <https://www.epa.gov/sites/default/files/documents/mats-erp.pdf>.

¹¹ See Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64661, 64877–79 (Oct. 23, 2015).

¹² Federal “Good Neighbor Plan” for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36654, 36770–74 (June 5, 2023).

¹³ The MATS process for securing an additional year of noncompliance was only invoked by a handful of units. See FERC, Commission Comments on Requests for EPA Administrative Orders, Docket Nos. AD16-9-000, AD16-10-000, AD16-11-000, 153 FERC ¶ 61,265, at 4–7 (issued Dec. 2, 2015); FERC, Commission Comments on Kansas City Board of Public Utilities’ Request for EPA Administrative Order, Docket No. AD14-16-000, 149 FERC ¶ 61,138, at 2–3 (issued Nov. 20, 2014); FERC, Commission Comments on Grand River Dam Authority’s Request for EPA Administrative Order, Docket No. AD15-6-000, 151 FERC ¶ 61,027, at 2–3 (issued Apr. 16, 2015); FERC, Commission Comments on Requests for EPA Administrative Orders, Docket Nos. AD16-9-000, AD16-10-000, AD16-11-000, 153 FERC ¶ 61,265, at 3–4 (issued Dec. 2, 2015). In the last of these cases, the units did not ultimately need the extra time. See EIA, *Form 923, Generation and Fuel Data for 2016*, (last visited Dec. 20, 2023) (showing zero coal consumption at Ames Units 7 & 8 from May 2016 onward). <https://www.eia.gov/electricity/data/eia923/> (last visited Dec. 20, 2023) (showing zero coal consumption at Ames Units 7 & 8 from May 2016 onward).

Although the CPP was never implemented, most states met their 2030 targets by 2019, suggesting that the rule’s state-level targets based on historical levels of deployment of cleaner generation would largely have been non-binding. See generally EPA, *Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units*, Ch. 2 (June 2019).

In recent years, states participating in NO_x ozone season emissions trading programs have exceeded their budgets in only one instance, and therefore have not needed to rely on the variability limits designed to accommodate unexpected power sector operations (or electricity demand). See EPA, *Good Neighbor Plan Results: First Ozone*

B. These industry trends are expected to continue and accelerate.

The transformation of the U.S. power grid is only projected to accelerate over the coming years. Economic factors, magnified by the IRA, are already accelerating the shift to cleaner generation, reducing electricity costs, and lowering climate and air pollution. A recent meta-analysis examined 11 independent analyses of the IRA, including EPA’s own modeling of the IRA, focusing on the impact of the IRA on power sector outcomes.¹⁴ The study found that the IRA increases the deployment of low-emitting capacity, such as renewable and carbon capture plants, resulting in the most extensive, sustained deployment of low-emitting resources and energy storage in U.S. history. Average growth rates for wind and solar ranged from 10–99 GW per year (56 GW/year average) annually through 2035 across the 11 models, well above the annual record (as of Nov. 2023) of 32 GW installed in 2021.

By 2035, the share of power coming from renewables, nuclear, and fossil plants with CCS ranges between 59–89 percent with the IRA (77 percent on average).¹⁵ The increase in clean energy reduces reliance on unabated fossil plants. By 2035, the 11 studies estimate that coal generation (without CCS) will decline by 44 percent to 100 percent (with an average of an 84 percent decline) from 2021 levels. The large declines in coal generation – and investment in new, cost-effective clean energy – result in significant cuts in CO₂ pollution from the power sector. By 2030, CO₂ emissions are 47–83 percent below 2005 levels (68 percent on average); by 2035, emissions are 66–87 percent below 2005 levels (78 percent on average). The range between different models tightens in 2035 and beyond as models converge given the additional time for lower technology costs, retirements, and ratcheting state policies to impact the investment and operation decisions of the U.S. power fleet.

As discussed in Commenters’ August submission, EPA’s modeling of a baseline without these rules (i.e., with just the IRA) is well-aligned with the average (central) estimates across the literature, if even slightly more conservative. EPA’s baseline tends to see more modest clean energy deployment, transmission expansion, and carbon reductions with just existing policy, such as the IRA, and expected technology performance.

The proposed rules are in EPA’s regulatory wheelhouse and reflect its long-standing Clean Air Act implementation practices. The emissions reductions secured by the proposal will be a modest

Season Under the Good Neighbor Plan (GNP), <https://www.epa.gov/Cross-State-Air-Pollution/good-neighbor-plan-results> (“Every state except Maryland reported power plant emissions below its prorated 2023 budget; Maryland’s emissions were well below its associated assurance level.”). Compare EPA, *State Budgets under the Revised Cross-State Air Pollution Rule Update*, <https://www.epa.gov/Cross-State-Air-Pollution/state-budgets-under-revised-cross-state-air-pollution-rule-update> (showing ozone season NO_x budgets for individual states for 2022), with EPA, Clean Air Markets Program Data, <https://campd.epa.gov/data/custom-data-download> (showing ozone season NO_x emissions at the state level for the Revised CSAPR Update below budgets in every state in 2022).

¹⁴ John ET Bistline et al., *Power sector impacts of the Inflation Reduction Act of 2022*, Env’t Rsch. Letters (2023), <https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b/meta> (Attach. 1).

¹⁵ *Id.*

increment to those that come from the current evolution of the power sector along with those stimulated by the IRA and state policies, and they are not the most significant factor driving change in the electric system—economic factors are. A recent report by The Brattle Group exploring reliability in tomorrow’s grid found the following:

While environmental and public health regulations are cited as a driver of the ongoing changes to the resource mix and the resulting reliability effects, it is clear from our review that: (1) as a result of economic factors, customer preferences, and state clean energy policies, much of the ongoing transition of the power supply mix and the resulting changes to system reliability needs will continue to happen with or without the environmental regulations; and (2) planning for timely responses to the ongoing changes to the resource mix ... will help maintain reliability.¹⁶

EPA’s proposal is incremental, building on the trends highlighted in this section that are already driving grid transformation. Furthermore, as discussed in Section III of these comments, even under sensitivity analyses that constrain the ability to deploy cost-effective clean energy and transmission solutions, the proposal, along with Commenters’ adjustments, can still be met at reasonable cost.

C. The coal fleet is aging, with significant retirements expected as units continue to reach the end of their useful lives.

The last decade has seen major changes for the economics and future of coal. The last large new coal power plant to open in the U.S. began operation in 2013.¹⁷ With no other coal plant additions, and with significant retirements over the past decade, coal-fired generating capacity dropped from just under 300 GW in 2012, to an estimated 179 GW by the end of 2023.¹⁸

A recent report by Sue Tierney of Analysis Group highlights three key factors behind these retirements: the lower cost of generating power from other resources like renewables, gas, and nuclear; climate and clean energy commitments made by states, business, and utilities that have resulted in them moving away from the dirtiest sources of energy; and the continued deployment of new renewable and gas-fired generation, as well as energy storage.¹⁹ All of these forces

¹⁶ Metin Celebi et al., *Bulk System Reliability for Tomorrow’s Grid* 6 (Dec. 20, 2023), https://www.brattle.com/wp-content/uploads/2023/12/Bulk-System-Reliability-for-Tomorrows-Grid_December-2023_Final.pdf (Attach. 2).

¹⁷ M. Tyson Brown, *Nearly a quarter of the operating U.S. coal-fired fleet scheduled to retire by 2029*, EIA (Nov. 7, 2022), <https://www.eia.gov/todayinenergy/detail.php?id=54559>.

¹⁸ EIA, *Short-Term Energy Outlook* (Dec. 12, 2023), <https://www.eia.gov/outlooks/steo/>; EIA, *68% of U.S. coal fleet retirements since 2011 were plants fueled by bituminous coal*, *Today in Energy* (Aug. 27, 2021), <https://www.eia.gov/todayinenergy/detail.php?id=49336>.

¹⁹ See generally Sue Tierney, *U.S. Coal-Fired Power Generation: Market Fundamentals as of 2023 and Transitions Ahead*, Analysis Group (Aug 8, 2023), <https://www.analysisgroup.com/globalassets/insights/publishing/2023-tierney-coal-generation-report.pdf>.

reduced the competitiveness of these aging plants and resulted in owners deciding to retire units as a cost-saving measure.

These underlying forces are strengthening due to incentives for clean energy in the IRA, and as additional states, cities, and businesses commit to clean energy targets. For example, electric co-ops can accelerate retirement of coal-fired EGUs with funding from the Empowering Rural America program. Tri-State Generation and Transmission Association plans to retire a unit two years early with the assistance of this funding.²⁰ Tri-State will build 1,250 megawatts of new renewable energy and energy storage by 2031 as part of its energy planning. Combined with the accelerated coal retirement, Tri-State is on track to cut its carbon footprint by 89 percent from 2005 levels by 2030. The utility estimates that this new plan will save its customers \$1.8 billion through 2043 as compared to its previous business-as-usual, while also “exceeding both industry-standard and heightened extreme weather reliability criteria.”²¹

The EIA expects almost half of the coal fleet to retire between 2023 and 2030 (from 198 GW in 2022 to 102 GW in 2030) without any new policy.²² This is in line with a recent analysis by The Brattle Group concluding that the 68 GW of planned coal retirements announced at the time of publication would likely be surpassed, based on a historical pattern of understated future coal retirements.²³ EPA’s modeling of the baseline found that the current fleet would continue to retire past 2030, to a total of 28 GW of unabated coal remaining in 2040 and another 8.5 installing CCS irrespective of the rule.²⁴

It is important to put these projected retirements in the context of the retirements seen historically. The level of retirements that occurred over the last decade (2013–2022) was more than double the rate of retirements expected under either the baseline (no standards) or EPA proposal scenarios. The 2012–2023 rate of retirement was 10.6 GW per year. The organizations managing reliability and safety of the grid successfully managed this transition. Between 2030–2040 (the compliance timeframe), the rate of retirement under Commenters’ modeling of the baseline (no policy) case is 4.3 GW per year, and in the EPA proposal case 5.0 GW per year.

²⁰ Jason Plautz, *Climate law cash speeds up Western coal plant closures*, E&E News (Dec. 5, 2023), <https://subscriber.politicopro.com/article/eenews/2023/12/05/climate-law-funds-speed-up-western-coal-plant-closures-00129904>.

²¹ *Id.*

²² EIA *Annual Energy Outlook 2023*, tbl. 9. Electric Generating Capacity (Mar. 16, 2023), <https://www.eia.gov/outlooks/aeo/>.

²³ Metin Celebi et al., *A Review of Coal-Fired Electricity Generation in the U.S.* (Apr. 27, 2023), <https://www.brattle.com/wp-content/uploads/2023/04/A-Review-of-Coal-Fired-Electricity-Generation-in-the-U.S..pdf>.

²⁴ EPA, *Analysis of the Proposed Greenhouse Gas Standards and Guidelines* (July 7, 2023), <https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines> (based on the results of the Updated Baseline released July 7, 2023).

D. The role of gas is expected to change over the coming years as renewable deployment accelerates.

The deployment of new renewable energy and energy storage technologies is also expected to affect the operation of existing gas-fired power plants. In analysis before the IRA, EPA projected declining capacity factors for gas-fired plants as additional renewable and storage resources are added to the grid.²⁵ Subsequent analysis shows that the IRA incentives amplify the decline in gas capacity factors as renewable deployment increases. Natural gas combined cycle (NGCC) capacity factors are projected to be around 64 percent in 2028 and 2030 in the Post-IRA baseline, with the average capacity factor for the combined cycle fleet falling to below 50 percent by 2035, 41 percent by 2040, and down to 31 percent by 2050 as additional renewable and storage capacity comes online due to economics.

In fact, in EPA's IRA baseline modeling, only 30 percent of existing gas capacity is projected to operate above a 50 percent capacity factor by 2035. That falls to 22 percent of existing gas capacity by 2040 and 16 percent by 2045. The capacity running as baseload represents 15 percent of all existing gas units operating in 2035, and less than 10 percent of all existing gas units operating in 2045.²⁶ Not all of these units running as baseload would be covered under the proposal (as some are likely below 300 MW). In other words, EPA's IRA baseline projects that at least 85 percent of existing gas units (representing 70 percent of gas capacity) would be operating below 50 percent capacity factor and not thus covered by the proposed rules.

Recently filed integrated resource plans (IRPs) indicate that companies also expect to utilize their new and existing gas units less in the future, in line with EPA's projections. For example, Ameren Missouri in its 2023 IRP assumes that NGCCs constructed in the future will run at 40 percent capacity factor, and newly built combustion turbines (CTs) at 5 percent.²⁷ Somewhat more conservatively, Tucson Electric Power's 2023 IRP shows NGCCs constructed in the future

²⁵ EPA, *Pre-IRA 2022 Reference Case* (Feb. 8, 2023), <https://www.epa.gov/power-sector-modeling/pre-ira-2022-reference-case>.

²⁶ With even higher deployment of renewables, as modeled in some studies examining rapid grid decarbonization, capacity factors at unabated gas units fall well below the proposed thresholds, including in a high-electrification scenario that assumes greater demand for electricity. Energy Innovation, *Maintaining A Reliable Grid Under EPA's Proposed 111 Rules Restricting Power Plant Emissions* 15–17 & Fig. 6 (Nov. 2023), <https://energyinnovation.org/publication/maintaining-a-reliable-grid-under-epas-proposed-111-rules-restricting-power-plant-emissions/> (Attach 3).

²⁷ Ameren Missouri, *2023 Integrated Resource Plan* Ch. 6, App. A, tbl. 6A.2, "Resources, Capacity and Performance," (2023), <https://www.ameren.com/missouri/company/environment-and-sustainability/integrated-resource-plan>.

operating at 50 percent capacity factor, and new CTs at 20 percent.²⁸ The company projects that utilization of its gas fleet overall will decline over the next 15 years, across multiple scenarios:²⁹

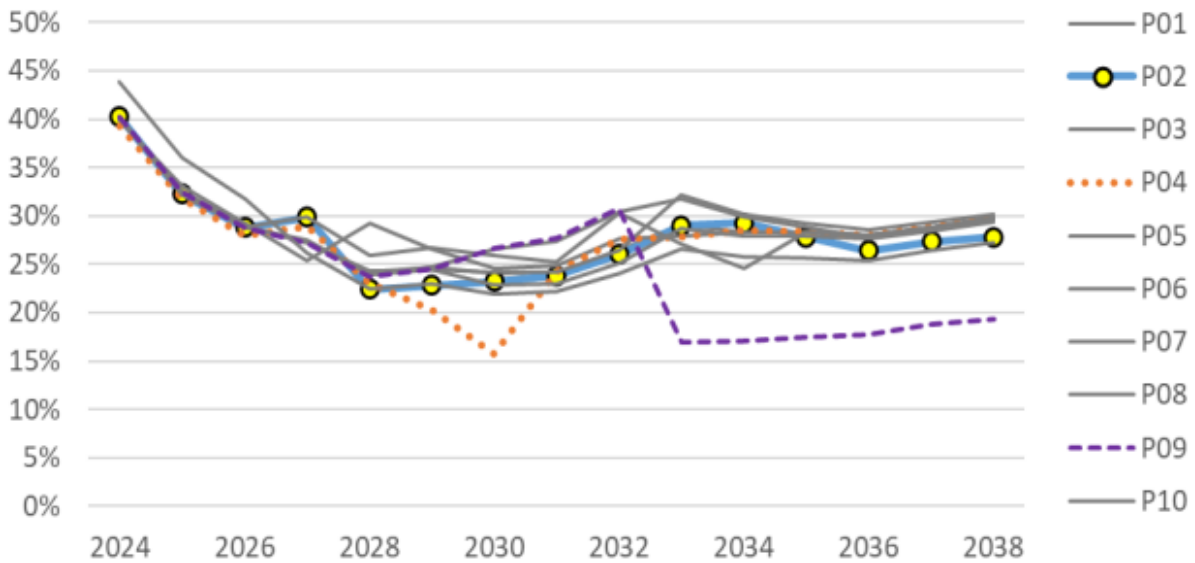


Figure 1. Gas Fleet Capacity Factor³⁰

Similarly, Southwestern Public Service Company (a subsidiary of Xcel Energy) projects shrinking generation from NGCCs as more renewables come online, with a pronounced narrowing of generation from NGCCs in the 2033–2035 timeframe:

²⁸ Tucson Electric Power, *2023 Integrated Resource Plan* App. K, tbl. 2 (Nov. 1, 2023), <https://www.tep.com/2023-irp/>.

²⁹ *Id.* at 50–51, Fig. 49.

³⁰ *Id.* (“Figure 49 shows the capacity-weighted, fleet-wide capacity factor for TEP’s gas-fired generators. Each portfolio’s use of natural gas, despite retirement of its coal units, decreases through the 2020s, primarily due to displacement by renewable generation, and increases slightly and stabilizes at about 27% in the 2030s. The portfolio that deviates somewhat from this trend is the P09 – SMR portfolio because SMRs are designed as baseload, high-capacity factor generators that displace more natural gas than renewables.”).

Energy by Technology Type

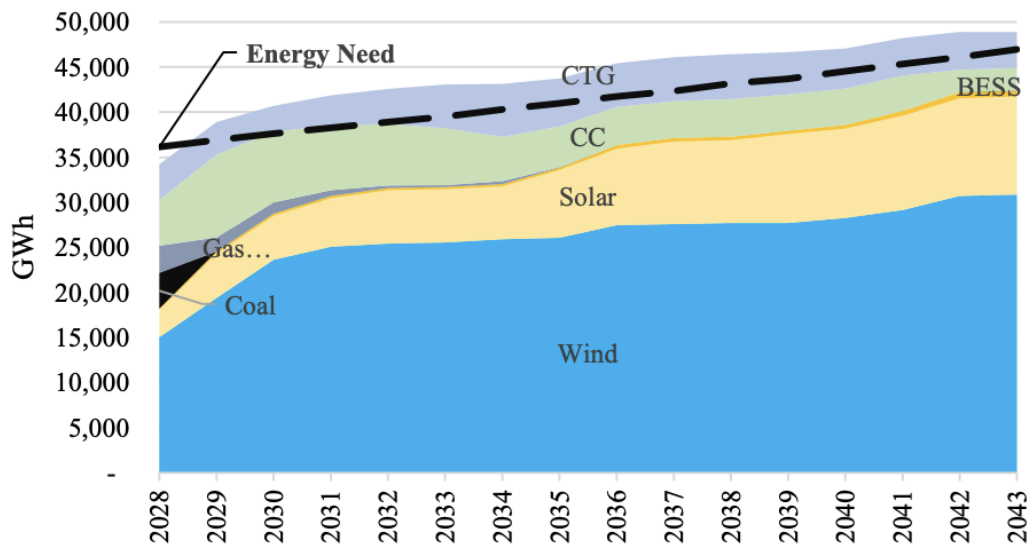


Figure 2. Most Cost-Effective Portfolios of Resources Multi-Jurisdictional Baseline Case – Energy by Technology Type (2028 – 2043).³¹

Regarding CTs, the company observes, “As the [combustion turbine generators] operate at a relatively low-capacity factor, as shown [above] in Figure 9F.4, [Southwestern Public Service Company’s] overall energy mix is increasingly dependent on wind and solar generation.”³² Thus, EPA’s proposed requirements for new and existing gas EGUs will have little, if any, effect on many companies’ plans for the continued, reliable operation of their fleets.

Figure 3 shows projected capacity factors for existing gas plants across different grid regions under business-as-usual conditions; in nearly all regions, average capacity factors for these units (of all sizes) are at or below 50 percent, and in most cases far below.

³¹ Southwestern Public Service Company, *2023 Integrated Resource Plan* 144 (Oct. 13, 2023), <https://www.xcelenergy.com/staticfiles/xcelresponsive/Company/Rates%20&%20Regulations/Resource%20Plans/2023%20SPS-IRP%20Plan.pdf>.

³² *Id.* at 143.

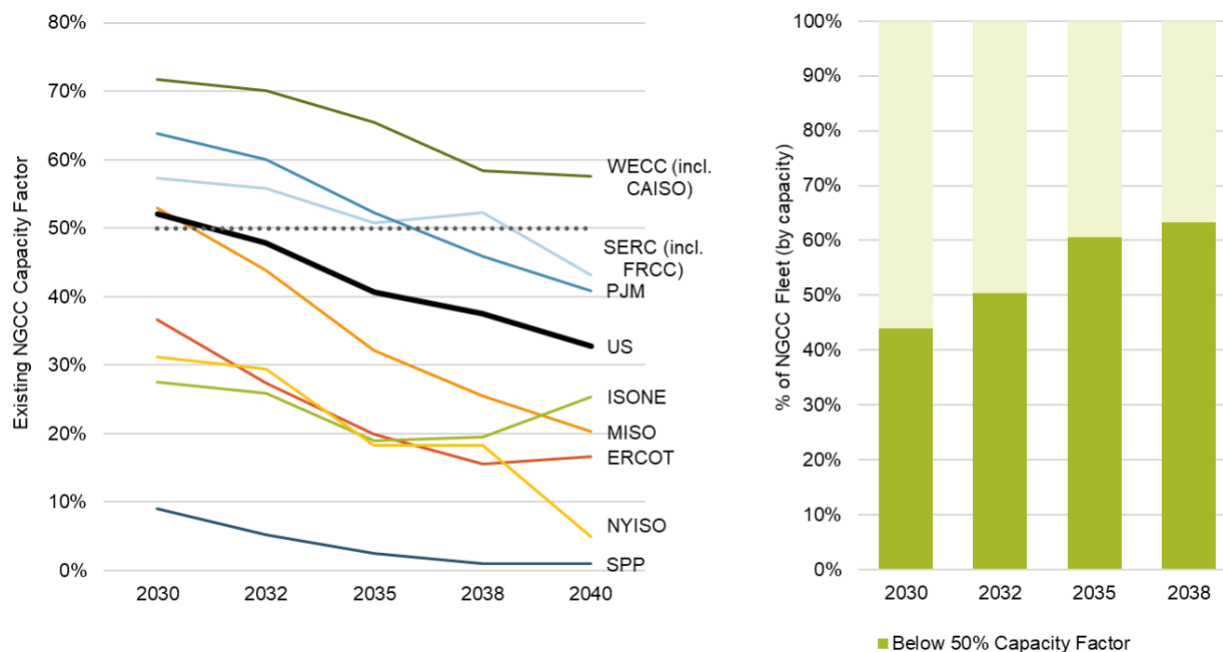


Figure 3. Downward Trend of Existing Gas Capacity Factors Under Business-as-Usual Conditions.³³

E. Renewables are already the cheapest form of new generating power, and with supportive state and federal policies - as well as corporate interest - the growth of these resources is only projected to accelerate.

With the last coal plant built in 2013, virtually all new power generation added to the U.S. grid between 2012 and 2022 has been wind, solar, water, and gas-fired generators or energy storage facilities. Of the 221 GW of net capacity additions over the decade, almost three-fourths were renewable facilities, with less than one-fourth of net capacity additions gas-fired.³⁴

This trend has continued into 2023. Wind, solar, and storage combined are estimated to make up 82 percent of new electric capacity additions this year, with solar accounting for more than half of that. The dominance of renewable and energy storage technologies comes down to economics. As shown in Figure 4, solar and wind have the lowest *unsubsidized* levelized cost of energy as of 2023. The cost of solar has fallen 83 percent since 2009 while the cost of onshore wind has fallen 63 percent. In comparison, the cost of a new NGCC has only decreased by 15 percent. And a

³³ Commenters' Integrated Planning Model (IPM) modeling.

³⁴ Tierney, *supra* note 19.

recent study found that over 99 percent of coal plants are more expensive to run than to replace with new renewable wind or solar energy.³⁵

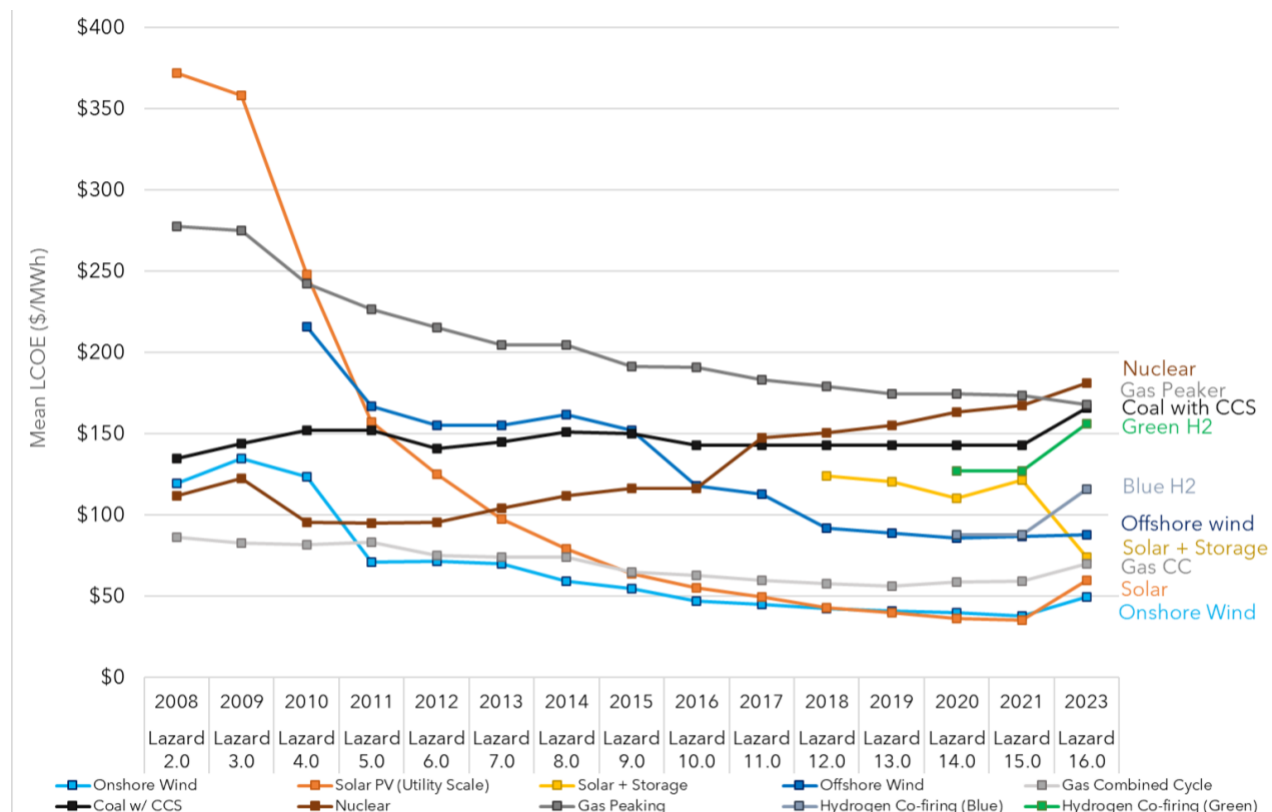


Figure 4. Unsubsidized Levelized Cost of Energy: 2008–2023.³⁶

New clean energy resources are even more cost-effective for utilities, businesses, and consumers given the power sector provisions of the IRA. As shown in Figure 5, when including the value of the IRA production and investment tax credits, the levelized cost of new renewables and solar plus storage can be equivalent to or lower than just the marginal (operating) cost of existing fossil-fired power plants. According to Lazard’s 2023 Levelized Cost of Energy Plus, the marginal operating cost of coal-fired plants ranges from \$29 to \$74 per MWh (mean of \$52/MWh) and NGCC plants range from \$51 to \$73 per MWh (mean of \$62/MWh). In contrast, when including the tax credit provisions of the IRA, the cost of new solar ranges from \$0 to \$88 per MWh and new wind ranges from \$0 to \$66 per MWh across the United States.

³⁵ Michael Solomon et al., *Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment*, Energy Innovation (Jan. 2023), <https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf>.

³⁶ Lazard, *Levelized Cost of Energy Plus* (Apr. 2023), <https://www.lazard.com/research-insights/levelized-cost-of-energyplus/>.

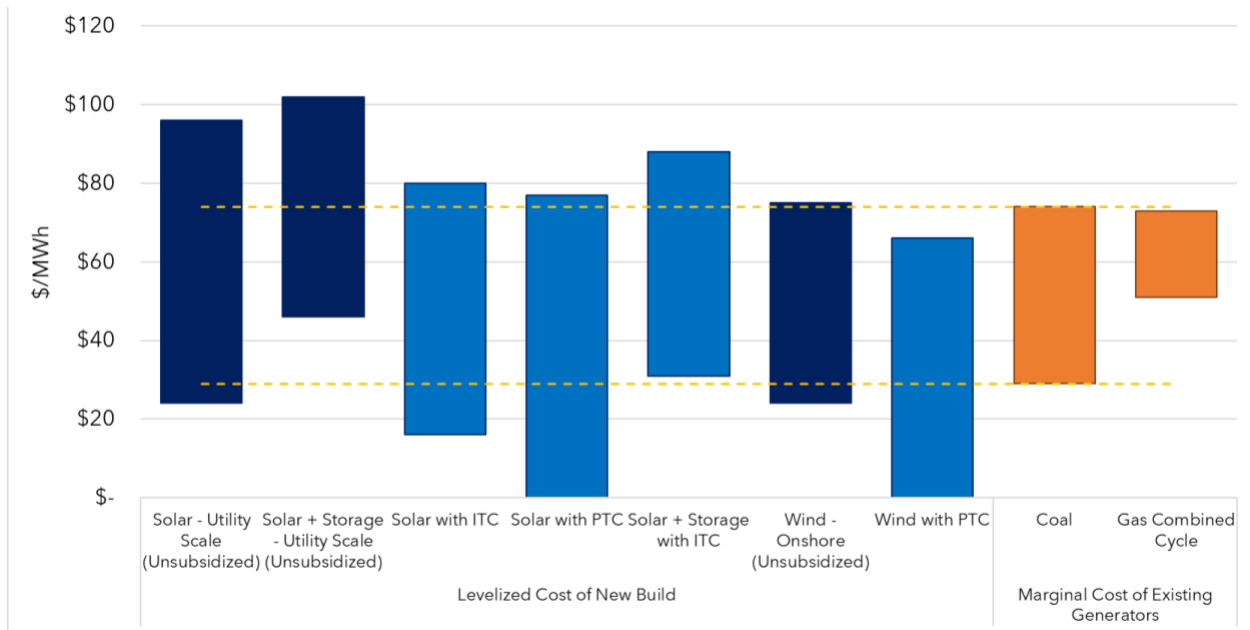


Figure 5. Levelized Cost of New Renewables versus Marginal Cost of Existing Fossil³⁷

Market trends are moving the power sector toward a future that relies more on renewable energy and less on fossil fuels. The rate of renewable deployment seen already demonstrates that the amounts of renewable energy projected to come online in both the baseline and EPA proposal case are reasonable. In Commenters’ modeling of the proposal, renewables are projected to be deployed at around 40 GW per year. This is only moderately over 2023 projected levels (38 GW) and below other modeling estimates of the impact of the IRA alone (for example, the previously cited meta-analysis by John Bistline et al. found that the average annual rate of deployment in IRA scenarios was 56 GW a year through 2035).

F. These business-as-usual forces set states and power companies up for cost-effective compliance.

The proposed rules add only modestly to the changes to the grid expected over the next decade and a half. Most of the expected changes are due to economics and existing policy. As discussed, given the falling costs of renewable and energy storage technology, an aging coal fleet, and existing policy support for clean energy investments at the state and federal levels, the power sector is already projected to see an acceleration of the clean electricity transition that has been underway in the power sector for the last decade. This proposal builds on these power sector trends, following the market forces and policy tailwinds. While the proposal does have an impact on the grid mix and is necessary to ensure that GHG emissions from remaining legacy technologies are well controlled, its incremental impact is modest. Changes under EPA’s

³⁷ *Id.*

proposal (as modeled by Commenters) in 2035 amount to just a 7 percent reduction in natural gas capacity and a 3 percent increase in wind and solar capacity as compared to the baseline.

Given these underlying market and policy forces, the portion of the fleet subject to the most stringent standards is small and continuing to shrink. The impact of the proposal, even with the recommendations made by Commenters, is incremental. Furthermore, given that the proposal is largely consistent with least-cost planning, the standards can likely be met by affected sources and states with minimal costs.

State energy planning shows that least-cost planning for a reliable grid can be consistent with EPA's regulations as proposed. For example, the Colorado Energy Office recently completed modeling for the state's energy pathways to 2040.³⁸ The lowest-cost mix of resources needed to reliably meet projected load - under a high electrification future - would result in carbon emission reductions of 98.5 percent by 2040 across Colorado. The least-cost pathway included adding "significant amounts of wind, solar, and batteries, while retaining a gas generation fleet approximately the same size as today's." The gas fleet would be decreasingly dispatched (used at decreasing capacity factors) over the years, with renewables and storage providing the vast majority of electricity annually. By 2040, gas would make up only 2 percent of the state's electricity mix. Over time, the levels of dispatch of gas units goes down dramatically from current levels. By 2032, only one gas unit was projected to be running as high as a 20 percent capacity factor; by 2038, no unit was projected to run above an 11 percent capacity factor. Will Toor, the Executive Director of the Colorado Energy Office, summed up these results: "Thus, simply by minimizing costs to customers, we will likely meet the EPA's requirements, since all coal plants in the state will be retired, and we are projecting that no gas plant will have a capacity factor that triggers the EPA requirements."³⁹

III. Modeling of the proposed rules shows continued reliable operation of the grid, even under constrained scenarios.

EPA and Commenters each have conducted numerous analyses exploring how the transition to a clean, low-emitting grid, including with the addition of the proposed standards, can be achieved at low cost and while maintaining reliability.

Specifically, Commenters conducted modeling of the proposal using the Integrated Planning Model (IPM), the results of which were submitted in comments in August.⁴⁰ Because the trends seen in the modeling of the proposed standards are continuations and, in some cases, modest accelerations of existing economic trends expected across the electric sector in the coming decades, the impact on total system costs of achieving these important incremental emissions

³⁸ Statement of Will Toor, Executive Director, Colorado Energy Office, FERC Reliability Technical Conference, Docket Number AD-23-9-000 (Nov. 9, 2023), <https://www.ferc.gov/media/will-toor-statement>.

³⁹ *Id.*

⁴⁰ Joint Comments, at Sec. VI D.

reductions is minimal. Indeed, through the relevant years, this modeling shows a reduction in system costs compared to the reference case; total system costs from 2025 through 2042 are extremely similar across analyzed cases. Costs also remain reasonable under a high demand sensitivity (reflecting a 10 percent increase in demand by 2035 and a 22 percent increase by 2050) compared to the baseline reference case, with costs decreasing 0.77 percent from 2025 through 2042 as compared to the reference case. In each of these cases, resource adequacy is maintained as costs remain reasonable; this modeling indicates that maintaining resource adequacy is possible without financially stressing the system. Thus, delays or uncertainty around finding adequate financing to timely implement compliance strategies should be minimal.

Some opponents to the proposed rules have argued that renewable resources will not be deployed rapidly enough to provide energy and capacity to replace retiring fossil resources (or reduced operations from remaining resources). We emphasize and describe in more detail below that some barriers to deploying renewables, for example, are under the control of grid operators, utilities, and regulators. These entities should be taking action now, regardless of EPA's proposed standards, to acknowledge and prepare for the reality of a rapidly transitioning electric system.

Even in scenarios where renewable resource deployment is slower than expected, however, analysis shows that reliability can be maintained (especially with appropriate planning and action on the part of grid managers). For example, Commenters ran a sensitivity analysis exploring the effects of the EPA proposal while imposing constraints on renewable and transmission buildout. That analysis shows reliable compliance with the proposed rules. This IPM scenario allowed no transmission expansion, limited total annual onshore wind and solar additions to 35 GW (which is below the deployment expected in 2023), and limited offshore wind to the levels required to meet existing state offshore wind targets.⁴¹ In this case, in order to meet resource adequacy requirements, IPM projects that additional gas capacity stays online (as compared to the unconstrained policy case) while running at capacity factors below 50 percent, especially in the 2035-2040 timeframe, after which retirements largely converge with the unconstrained policy case. This case does not project significant additional deployment of CCS.

Commenters also worked with ICF to complete additional resource and energy adequacy assessments of the IPM modeling submitted in the August comments. The projected fleet under the proposed EPA standards from IPM was run through a more detailed, hour-by-hour energy adequacy assessment in the PJM region.⁴² PJM is the nation's largest grid operator that covers 13 states, from Illinois to New Jersey and down through parts of North Carolina, and currently relies heavily on fossil fuel-fired power plants. The analysis examines both winter and summer peak

⁴¹ Elesia Fasching & Suparna Ray, *More than half of new U.S. electric-generating capacity in 2023 will be solar*, EIA (Feb. 6, 2023), <https://www.eia.gov/todayinenergy/detail.php?id=55419>.

⁴² ICF, *Review of Expected Resource Adequacy in PJM under Stress Conditions during Summer and Winter Peak Periods* (Nov. 9, 2023), <https://www.nrdc.org/sites/default/files/2023-11/icf-caelp-nrdc-edf-peak-stress-resource-modeling-20231109.pdf> (Attach. 4).

stress weeks in 2030, 2035, and 2040, to assess whether PJM’s projected generating resources under EPA’s proposal would provide adequate energy hour by hour under “weather stress” conditions. The “Weather Stressed” scenario was designed to reflect the simultaneous impact of a one-in-ten-year weather extreme on load and a one-in-ten-year poor renewable resource availability for both the summer and winter peak weeks. These stressed scenarios are similar to the one-blackout-in-ten-year standard PJM plans for now.

The analysis found that even under these stressed conditions, PJM had sufficient capacity to meet demand in all hours over both the summer and winter extreme weeks. In other words, the projected capacity mix in IPM under EPA’s proposal can meet PJM’s energy needs even with extreme weather and low renewable output for all years studied out through 2040. The analysis found that for only a small fraction of hours (nine hours of the more than 300 hours studied) would PJM need to rely on either electricity imports from outside the region or use demand response resources. The nine hours all occurred during a brief period of the 2030 summer stress week, and the study showed the need for obtaining 2.7 GW from either imports or demand response, which is well within PJM’s current assumptions about the availability of power imports in its current reserve requirement study (3.5 GW), and well within PJM’s already contracted-for demand response capability (5 GW).⁴³

Commenters also commissioned ICF to assess an even more extreme scenario, reflecting our preferred policy case under high demand conditions.⁴⁴ The Preferred Policy Case strengthened

⁴³ This exercise models a weather stressed scenario on a static capacity mix projected by IPM which doesn't solve specifically to meet these stressed scenarios. Grid operators, if conducting these analyses and coming to similar conclusions, could choose to pursue or deploy a capacity mix that performs even better in these weather stressed scenarios between now and the years tested.

⁴⁴ ICF, *Review of Expected Resource Adequacy in PJM under Stress Conditions and High Demand during Summer and Winter Peak Periods* (Dec. 19, 2023), <https://www.nrdc.org/sites/default/files/2023-12/pjm-peak-stress-resource-adequacy-review-icf-20231219.pdf> (Attach. 5).

The Preferred Policy Case strengthened the proposed standards for all EGU types—new gas, existing gas, and existing coal units. These changes include:

Advance the date for the subcategory of long-lived coal units from 2040 to 2038.

For the subcategory of units retiring after 2030 but before 2038 and running at low-load (less than 20 percent capacity factor), the emission limit should be based on maintaining historical emission rates.

For the subcategory of units retiring within this timeframe but running more than 20 percent of capacity, the emission limit should be based on 40 percent co-firing of gas by heat input.

For baseload new gas-fired EGUs, lower the applicable capacity factor to 40 percent and set the emission limit based on 90 percent post-combustion capture and sequestration starting in 2035.

For the new gas intermediate load subcategory, lower the capacity factor limit from about 50 percent to 40 percent. Set the first phase emission limits based on efficient operation of the type of combustion unit (setting separate standards for simple and combined cycle units). Set the second phase emission

the proposed standards for all EGU types—new gas, existing gas, and existing coal units. Furthermore, the high demand sensitivity increased total electric demand across the model period in line with projected increased energy demand due to advanced electrification beyond what is already projected in Annual Energy Outlook 2023. This results in a 10 percent increase in demand by 2035 and a 22 percent increase by 2050 compared to the baseline case.⁴⁵ The analysis did not change the underlying load shape in IPM, however. Therefore, the load shape does not reflect any change of demand shape or load profile due to the increase in load associated with transportation electrification, which is likely to occur off typical peak and/or include additional controls. This scenario thus may reflect a “peakier” system than what may actually be observed.

Under this extreme scenario, the analysis continued to find sufficient energy adequacy across the PJM region, even during stressed winter and summer conditions and under this conservative analytical framework.⁴⁶ In the peak weeks of the 2030, 2035, and 2040 Weather Stressed case, there are 12 to 14 hours of required capacity in excess of that assumed to be available within PJM. Up to 9.1 GW, or roughly 5 percent of the hourly demand in those hours, was required to be served by non-PJM generating capacity, such as imports or contracted load management. The additional need in each year is below the combined total of PJM’s Capacity Benefit Margin of 3.5 GW and PJM’s reported 7.4 GW of load management committed for summer availability. Further, this does not account for any increased demand response likely to be available from the increasing portion of demand coming from electrified transportation.

limit based on 30 percent low-GHG hydrogen co-firing, ramping up to 90 percent low-GHG hydrogen co-firing in the third phase.

Lower the capacity factor limit for the new gas low-load subcategory to no higher than 15 percent. Set the emission limit based on 30 percent low-GHG hydrogen co-firing starting in phase 2.

Define the subcategory of existing gas units subject to a CCS-based emission limit on a plant-wide, rather than a unit, basis. Apply the CCS-based emission limits to EGUs located in plants with total gas-fired capacity above 600 megawatts (MW) and a plant-wide capacity factor for gas-fired units of more than 45 percent.

See Joint Comments, at Sec. VI.

⁴⁵ *See* Joint Comments, Appendix C for more detail.

⁴⁶ *Review of Expected Resource Adequacy in PJM under Stress Conditions and High Demand during Summer and Winter Peak Periods supra* note 44.

IV. The proposal is incremental and designed to accommodate the dynamic role of the source subcategories to adequately support grid reliability.

As discussed in our August Comments, Sec. VIII A, the proposed rules include numerous design mechanisms that allow for flexible, reliable operation of the grid.⁴⁷ The proposal’s design flexibilities take into account existing power sector practices to ensure a reliable grid. A flexible regulatory structure allows many resources to continue to operate at (and even significantly above) historic and business-as-usual projected levels without triggering compliance obligations, and annual averaging of capacity factors also provides significant flexibility. Ample lead time for compliance allows grid operators and utilities to plan for operational impacts of compliance, in particular for coal plants. State plan flexibilities for existing units offer potential options to support reliability. Additionally, increments of progress and milestones will ensure timely compliance and advance warning of any slipping.

The discussion that follows describes the proposal’s several design features supporting a reliable electric system while simultaneously meeting the statutory directive to reduce air pollution.

A. A flexible regulatory structure for gas plants facilitates peaking and coverage for extreme weather events.

The proposal provides for less stringent standards for gas units that operate and pollute less frequently, allowing those units to continue to operate in a peaking capacity to support grid reliability.⁴⁸ Both existing large baseload and new baseload gas facilities are only subject to CCS-based standards if they exceed (approximately for new gas) an annual 50 percent capacity factor, which as discussed above is an increasingly small portion of the fleet. In addition, most existing natural gas combustion turbines are below the 300 MW nameplate capacity threshold

⁴⁷ Proposal at 33415 (detailing numerous design element flexibilities in the proposal to address resource adequacy and facilitate planning, empowering grid planning authorities to maintain system reliability); *See also* EPA, *Resource Adequacy Analysis Technical Support Document* (Apr. 2023), <https://www.regulations.gov/docket/EPA-HQ-OAR-2023-0072/document>; Susan Tierney, *Electric Reliability and EPA’s Regulation of GHG Emissions from Power Plants* 35 (Nov. 7, 2023), <https://www.analysisgroup.com/globalassets/insights/publishing/2023-tierney-electric-reliability-and-epa-ghg-regs.pdf> (noting that while “resource adequacy considerations indeed differ from operational reliability ones, [] EPA has not erred in modeling only the former” because “[i]t would be unrealistic to expect that EPA ... know the specific future compliance decisions of power plant owners that would be required to conduct meaningful detailed system impact studies across all regions of the country affected by the new standards starting nearly a decade from now”).

⁴⁸ *See, e.g.*, Proposal at 33415 (explaining that existing gas units operating below a 50 percent annual capacity factor support resource adequacy under the proposed rules because these plants are not subject to standards and would “be able to operate at higher levels during times of greater demand, thereby maintaining their capacity accreditation values”).

and would not be covered.⁴⁹ Even with significantly reduced annual capacity factor thresholds, as several commenters have called for, the thresholds still provide ample room for gas plants to be used for intermediate and peaking energy needs.⁵⁰

The proposed annual calculation of capacity factors for both existing and new units further supports reliability in extreme weather events. Annual calculation of capacity factors provides significant flexibility to gas plants to ramp output to meet operational needs while still staying below proposed thresholds for pollution standard coverage.⁵¹ As an example, an existing gas plant could run at 100 percent capacity factor during all peak hours of a 40-day extreme heat period (from 4-7pm), 80 percent for the remainder of all hours during those days, and 46 percent the rest of the year and remain under the proposed 50 percent capacity factor threshold. During Winter Storm Uri, if an existing gas plant had been called on to run for the entire 11-day duration of the storm at 82 percent capacity factor, it could have run at a 49 percent capacity factor for the remainder of the year and still fallen below the proposed 50 percent annual capacity factor threshold. *See* Figure 6.

⁴⁹ *See* Susan Tierney *Electric Reliability and EPA's Regulation of GHG Emissions from Power Plants* 29–30, (Nov. 7, 2023), <https://www.analysisgroup.com/globalassets/insights/publishing/2023-tierney-electric-reliability-and-epa-ghg-regs.pdf>; Comments of Environmental Defense Fund, Docket ID No. EPA-HQ-OAR-2023-0072, at 36 (Aug. 15, 2023), <https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0764> [hereinafter EDF 2023 Comments].

⁵⁰ *See, e.g.*, Joint Comments at 70, 72–73, 76, 97, 101; Comments of Sierra Club, Earthjustice, Conservation Law Foundation, and Appalachian Voices, Docket ID No. EPA-HQ-OAR-2023-0072-0813, at 19–20, 26–27 (Aug. 18, 2023); EDF 2023 Comments at 32–34, 36–38.

⁵¹ CAELP, *Reliability: Power of Averaging* [Infographic], <https://static1.squarespace.com/static/5a1aca61ccc5c5ef7b931da7/t/6544f09f616b42026d271bd0/1699016911357/reliability-power-of-averaging>.

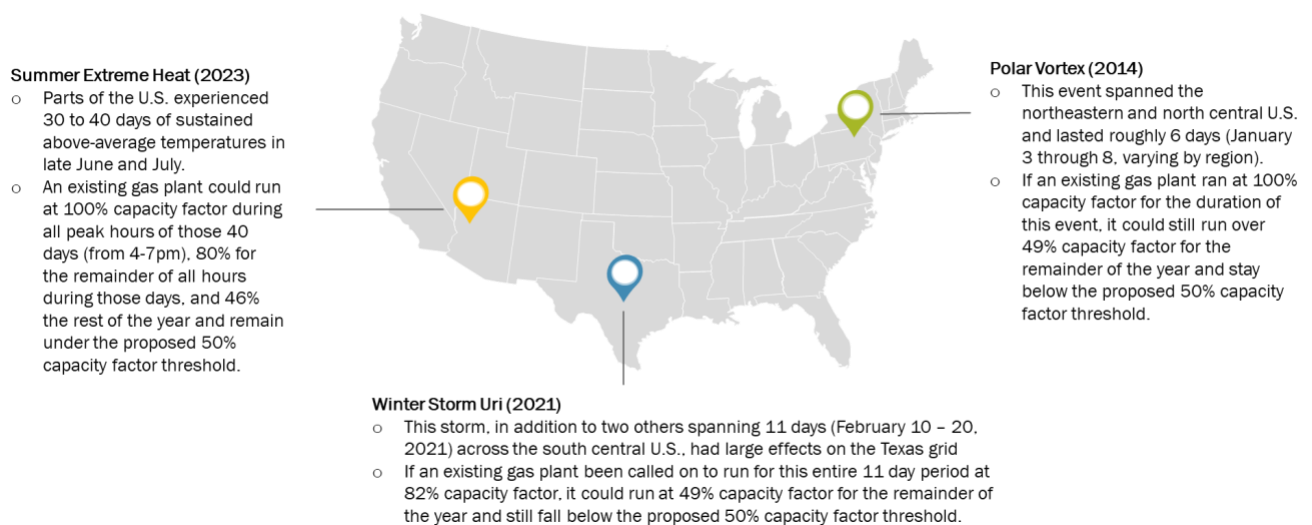


Figure 6. The Power of Averaging⁵²

B. Ample lead time for compliance supports reliability.

In response to the longer-term and longer-duration reliability concerns, the proposed standards provide power plant owners and operators ample time to install selected pollution control systems while supporting continued power generation to the grid, and grid operators and utilities the time to engage in planning. Most of the proposed standards, especially the most stringent, do not require compliance until several years out to accommodate various logistics such as obtaining control equipment, permitting, construction, supply chain issues and infrastructure build out. For coal units, the proposed CCS-based standard does not require compliance with the rate until 2030, and for gas units, compliance begins in 2035. The hydrogen pathway for new and existing gas requires that units co-fire with 30 percent low-GHG hydrogen by 2032. Given that the earliest compliance date is six years following promulgation of the final rule (assuming it is published in the spring of 2024), owners/operators have sufficient time to facilitate the planning, permitting, contracting, and installation activities required for deployment of the control technologies,⁵³ or development of replacement generation in advance of the compliance date.⁵⁴

⁵² *Id.*

⁵³ *See infra* at Appendix B.

⁵⁴ *See, e.g.,* Tierney, *supra* note 49, at 30 (“Note that current estimates of lead times for permitting and constructing new non-renewable capacity are: 24 months for battery storage; 36 months for gas-fired simple cycle CTs; and 48 months for gas-fired combined cycles. Even a doubling of such time frames – such as to account quite conservatively for permitting delays or other extensions of lead times for individual projects – could allow for the economical and timely development of new facilities. Many projects are already in interconnection queues or in development, permitting, financing, and/or construction stages, and may be completed and interconnected in the years leading up to proposed implementation of the more stringent elements of EPA’s proposals (e.g., post 2032).”).

C. Subcategories for coal units facilitate long-term planning.

EPA’s regulatory design for existing coal units gives owners and operators the option to continue providing baseload power generation without the need to install new controls in the near term. The subcategory approach proposed for existing coal units was initially suggested by the industry⁵⁵ and provides greater investment certainty. EPA’s subcategories are structured on the basis that the cost reasonableness of capital-intensive emissions controls depends on how long the unit will be operating and thus over how many years the investment can be spread. As a result, the proposal provides that standards reflecting technologies such as CCS will be applicable to coal units that plan to operate after 2040. Those committing voluntarily to enforceable retirements before 2035 are subject to standards based on routine maintenance, not investment in CCS. And as discussed above, at Sec. II C, those with retirement commitments are a significant portion of the coal fleet.

Some grid operators have raised concerns about lack of visibility into generator retirements. EPA’s proposal will provide additional visibility by requiring operators to opt into subcategories and reveal their committed retirement dates and/or capacity factors. This will improve grid operators’ ability to plan. Thus, as Ric O’Connell testified at the Federal Energy Regulatory Commission (FERC) Reliability Technical Conference on grid reliability, “these new rules will actually bolster reliability by providing the regulatory certainty needed to effectively plan in a coordinated manner with actionable deadlines.”

Reliability authorities would gain dependable long-term information about future generation capacity available to serve the grid over the next decade and beyond, filling a gap that grid regulators identified at the recent FERC technical conference.⁵⁶ If the proposal is finalized on schedule, states would submit state plans to EPA, including owner and operator subcategory elections, by June of 2026.⁵⁷ Reliability authorities will have knowledge of the federally enforceable retirement dates by no later than the summer of 2027. In short, EPA’s proposal improves transparency regarding retirements and provides ample lead time for the relevant authorities (including the state and federal environmental agencies and FERC and grid operators) to respond.

⁵⁵ Proposal at 33245.

⁵⁶ FERC Technical Conference on Reliability, Reliability Impacts of 111 Proposal [Transcript], Docket No. AD23-9-000, FERC Commissioner Danly at 175 (lines 7–25), 176 (lines 1–3), (discussing concern expressed by MISO in morning reliability panel – that MISO is not always aware of upcoming retirements and that RTOs have trouble managing grid reliability when unexpected retirements occur that the RTO did not anticipate); *id.*, Emily Fisher, Executive Vice President, Clean Energy Council & General Counsel, EEI, at 200 (lines 10-13, 22-25), 201 (lines 1-3) (sharing that EEI proposed the voluntary subcategory approach in EPA’s non-regulatory docket preceding the proposal, and that in two years reliability authorities will have a great sense of which plants will retire); *id.*, Ric O’Connell, Executive Director, Grid Lab at 202 (lines 5–20) (stating that Section 111 state plans bolsters reliability by providing actionable deadlines, information to utilities, and long timelines with regulatory certainty).

⁵⁷ Proposal at 33397, 33402–03.

In addition, as described more fully in the following subsection, the proposal's progress and compliance milestones include requirements for unit owners and operators to work with local reliability regulators to conduct reliability planning well in advance of a unit's retirement.⁵⁸ Owners and operators would also post all recordkeeping and reporting information to public websites accessible to all grid authorities, including subcategory elections and compliance schedules.⁵⁹ EPA's proposal therefore facilitates the very kind of forward-looking and transparent capacity and reliability planning that will empower grid operators with detailed and accurate information to better inform long-term planning.

The subcategory approach thus supports reliability by ensuring the cost reasonableness of the regulatory framework, as well as by providing clarity to grid operators about future retirements of coal generating capacity.

D. State plan flexibilities for existing units offer potential options to support reliability and increments of progress and milestones allow for planning.

In the case of existing sources, states have additional flexibility to develop their own state plans that accommodate their fleet and set performance standards for affected units. While states may opt to apply the presumptively approvable standards to each of their existing sources, EPA has also indicated that states may take advantage of compliance flexibilities so long as plans demonstrate equivalence to the stringency that would result if each affected EGU was individually achieving its standard of performance.⁶⁰

States also have the authority to issue variances based on considering RULOF that apply a less stringent standard or compliance time if circumstances specific to the source are fundamentally different from the information EPA considered in selecting the best system of emission reduction for the relevant subcategory.

⁵⁸ For example, facilities must submit to state administering authorities Initial Milestone Reports either five years before the enforceable retirement date or 60 days after the state plan submission, whichever is later, documenting key milestones in their planning and implementation, including "correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority." Proposal at 33390.

⁵⁹ Proposal at 33400.

⁶⁰ As described in detail in two new reports from Andover Technology Partners, individual EGUs have numerous options for complying with the proposed emission limitations, the full potential of which could be unlocked through trading and averaging of emissions; and this flexible approach to compliance is consistent with a long history of EPA rules issued under the Clean Air Act, following Congress's instructions and promoting the statutory purpose of advancing air pollution control technology. *See generally* Andover Technology Partners, *Compliance Options Available to Individual Power Plants Under the Proposed Clean Air Act Section 111 GHG Rules* (Dec. 18, 2023), <https://www.andovertechnology.com/articles-archive/> (Attach. 6); Andover Technology Partners, *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations* (Dec. 18, 2023), <https://www.andovertechnology.com/articles-archive/> (Attach. 7).

The state plans must also include increments of progress or milestones. Because the proposed timelines are long (compliance is more than 20 months from plan submission) and the steps to achieve compliance are multiple, the Section 111(d) implementing regulations require increments of progress. The increments of progress are designed to “ensure standards of performance are implemented as expeditiously as possible so that the intended emission reductions are achieved, and the public health and welfare are protected.”⁶¹

Each state plan must include specified enforceable increments. For example, if an owner or operator is planning on complying with a standard via CCS, certain increments must be included for the following actions:

- (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must ... include[e] supporting analysis for the affected EGU’s control strategy, including a feasibility and/or FEED study.
- (2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification. ...
- (3) Initiation of onsite construction or installation of emission control equipment ...
- (4) Completion of onsite construction ...
- (5) Final compliance.⁶²

Separate increments are also proposed for owners or operators planning to comply with the standard via natural gas co-firing or low-GHG hydrogen co-firing.

If an EGU’s owner or operator intends to retire a unit by the date provided by the relevant subcategory, EPA is proposing legally enforceable milestone reporting requirements, which count backward from the closure date to ensure timely progress. These requirements include, among other things, an Initial Milestone Report which summarizes the steps toward ceasing operations and timing for those steps, metrics to assess whether steps have been met, indications of notice to reliability authority and retirement filings, comparison with the retirement timelines for similar sources, and supporting regulatory documents. The source must then each year file a progress report toward retirement.⁶³

In addition to ensuring timely progress, these increments of progress also provide the very transparency into the source operator’s plans that reliability officials now say they lack. They also provide an early warning if a timeline is slipping for reasons outside of the control of the owner or operator that should alert owners and operators and states that a plan revision may be required.⁶⁴

⁶¹ Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), 88 Fed. Reg. 80480, 80497 (Dec. 18, 2023).

⁶² Proposal at 33389.

⁶³ *Id.* at 33390.

⁶⁴ Discussed further at Sec. VI A.

EPA’s proposal could be further bolstered by requiring state environmental or air agencies to document, briefly, their consultation with relevant state-level planning authorities as well. EPA included such a requirement in the CPP, responding to comments of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), and requiring documentation of state agencies’ consultation with planning authorities when developing state plans.⁶⁵ A similar requirement is particularly important under the proposed rules here, as they involve decisions about operating horizons that determine sources’ placement into subcategories. This requirement should not extend the time needed for the state to develop and submit its plan to EPA. And, as EPA noted before, consultation with planning authorities “should further help states avoid any conflicts between state plans and the maintenance of reliability during implementation of the state plan and associated emission standards.”⁶⁶

V. Reliability authorities, states, grid planners and operators, and power companies have tools and authority to address any reliability challenges.

In setting pollution standards and guidelines under Section 111 of the Clean Air Act, EPA must choose the best system of emission reduction taking into account, among other things, energy requirements.⁶⁷ As part of this requirement, in developing the proposed rule, EPA “considered the importance of maintaining resource adequacy and grid reliability,” and maintaining reliability was a “paramount consideration.”⁶⁸ As discussed above, EPA designed the proposal to give the utilities and system operators flexibility to maintain and strengthen the grid’s reliability.

While EPA has considered reliability issues in its proposal, FERC is the agency with direct jurisdiction over electric reliability. As discussed above and as recognized by FERC, the electric grid is undergoing changes unrelated to the EPA proposal and the proposed regulations are only incremental to these existing forces. FERC and the electric utilities have the responsibility and many tools available to them to ensure reliability as these grid changes occur.

As Dr. Susan Tierney testified at the recent FERC Reliability Technical Conference, and as discussed in Appendix A, a common theme among prior EPA power plant rules is that industry stakeholders raised reliability concerns. Dr. Tierney noted, however, that “[i]n each instance in the past dozen years, the industry and other stakeholders predictably stepped up to ensure that actual reliability was not compromised.”⁶⁹ While the electric markets have changed since the last EPA power plant rules, the tools available to grid operators and utilities to ensure reliability

⁶⁵ Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64661, 64877 (Oct. 23, 2015).

⁶⁶ *Id.*

⁶⁷ 42 U.S.C. § 7411(a)(1).

⁶⁸ Proposal at 33246, 33415.

⁶⁹ FERC Technical Conference on Reliability, Reliability Impacts of 111 Proposal [Transcript] Docket No. AD23-9-000 (testimony of Dr. Susan Tierney) at 193 (lines 7–9).

remain sufficient. In fact, as Dr. Tierney has shown, “the electricity reliability institutions, tools and processes in place today actually are better than they were in those other instances.”⁷⁰

FERC has jurisdiction over electric reliability under the Federal Power Act (FPA). This jurisdiction is exercised in two ways. First, FERC has direct authority to adopt reliability standards developed by the North American Electric Reliability Corporation (NERC) or require NERC to develop standards that generators and others must follow. These standards cover issues such as transmission planning and operations and emergency planning and operations. For example, NERC recently developed, and FERC approved, reliability standards governing how generators address extreme cold weather. FERC also required NERC to further improve those standards.

Second, FERC regulates the rates and services for wholesale power sales and electric transmission in interstate commerce. The rules approved by FERC affect many aspects of ensuring reliability, including interconnecting new generation to the grid, ensuring the right services are available to ensure reliability, removing barriers to new resources in the markets, and planning new transmission.

ISOs and RTOs also have substantial authority and responsibility for reliability. ISOs/RTOs serve two-thirds of the electric load in the United States. They use energy markets to dispatch generators and maintain grid reliability. Utilities within ISO/RTO regions can use these markets to obtain power from generators across a wide footprint, using a coordinated transmission system. These markets use bid-based mechanisms to determine which generators run and send price signals to incent efficient entry and exit from the power markets—ensuring the development of new resources to replace those that are retiring. FERC is responsible for oversight of these ISOs/RTOs, providing guidance and requirements for and approval of their market designs and operations.

FERC, the ISOs/RTOs, and utilities can and must address the reliability implications of the changing energy landscape, most of which are presented irrespective of EPA’s standards. These entities have numerous existing tools, some of which are described below, that can help them fulfill their obligations under the FPA to support and maintain reliability. And these entities must go further to develop new tools (or hone their existing ones) to account for the changes coming in the energy sector regardless of EPA action. As The Brattle Group has noted in a forward-looking study about reliability of our future grid:

The electric grid is constantly evolving, and the institutions of the power sector continuously learning, improving, and adapting. The evolution of the coming years will progressively shift the relative size and importance of today’s challenges, but at a high level it is not likely to categorically transform them. As in the past, tools and processes

⁷⁰ *Id.* at 193 (lines 21–23).

to manage those challenges will need to evolve to match their changing nature, and innovations will build off prior developments.⁷¹

FERC, the ISOs/RTOs, and utilities operating in both competitive and vertically integrated markets must address long-term reliability needs while planning for generating resources to be cleaner. As both the baseline and regulatory cases show, this entails the challenge of replacing existing resources as they retire for economic reasons with sufficient quantities of new cleaner resources, and this will often entail replacing legacy resources with larger quantities of a mix of technologies including wind, solar, and advanced storage. Larger quantities of GWs will be needed to account for the intermittency of some resources and many of these new resources will be more broadly dispersed than retiring central station coal and natural gas baseload units, which will have implications for the transmission system. FERC, the ISOs/RTOs and some state regulators have various long-term reliability initiatives underway and those deserve additional attention; others have been recommended by experts and should be pursued urgently.

FERC, NERC, and grid operators have tools and authority they need to address the energy transition. They can:

- Conduct planning and market reform for changing resource mixes: In 2022, FERC required each ISO and RTO to submit a report to FERC detailing its current system needs given changing resource mix and load profiles and how those needs will change over the next 5 and 10 years. FERC also asked the ISOs/RTOs about their plans to reform their markets to meet these expected system needs. Each ISO and RTO filed substantive comments indicating key changes they plan for their markets. FERC has yet to act in this proceeding.
- Ensure that FERC-jurisdictional markets allow all resources that can provide a reliability grid service to do so and that market barriers do not block their participation: grid operators need to work to increase participation of demand response and other demand-side resources that can quickly reduce power demand during extreme weather events without increasing dependence on vulnerable fossil fuels. This includes ensuring that the ISOs and RTOs robustly implement a 2020 FERC rule requiring that they allow aggregated distributed energy resources nondiscriminatory access to their markets and that FERC remove an unjust and unreasonable rule that allows states to prohibit demand response from participating in wholesale markets. FERC opened a Notice of Inquiry to remove this so-called “opt-out” in 2021 but has not yet acted to remove the provision.
- Modify market rules, software, and operations to capture the full potential of flexible battery storage resources and inverter-based resources: these resources often provide grid-stabilizing services that are superior to thermal generators, but current system functions often limit or exclude their participation. As Brattle has noted, “By leveraging

⁷¹ Celebi et al., *supra* note 16, at 65.

the Essential Reliability Services capability of inverter-based resources, monitoring the availability of such services and comparing it with the need, and procuring additional services when required, operators can ensure that the grid can sustain unavoidable disturbances and return to normal conditions quickly.⁷² Grid operators must recognize the reliability services of these resources and make appropriate reforms to markets and processes that will play an increasing role in operations.

- Assess whether market rules and operations appropriately value the reliability contribution of various resources: in doing this, ISOs/RTOs must ensure that they do not undervalue the contribution of variable renewable resources or overvalue the contribution of fossil-fired generation, particularly given the recent failures of fossil generation during extreme weather events. As Brattle has noted, “[w]ell-designed pricing can facilitate the rapid development of flexible resources, increasing installed flexibility while deploying it optimally and paying prices that appropriately reflect trade-offs associated with not having the flexibility.” This study notes an example of how, driven largely by ancillary services pricing, flexible battery capacity in the Electric Reliability Council of Texas (ERCOT) increased from 0 GW in 2018 to 3 GW as of October 2023.⁷³
- Undertake common-sense interconnection reforms: another key role for FERC, the ISOs/RTOs, and utilities is to ensure that new generation can come online quickly. While FERC recently issued a rule which will fix some of the most glaring inefficiencies with the interconnection process, more can and must be done. Grid operators can and should take steps to fast-track replacement generation that reuses the interconnections of retiring generation, identify locations on the existing grid where new generation can connect with minimal network upgrades, and study interconnection applications using realistic models of resource output and system conditions. Most critical, however, is that the current patchwork of siloed processes must evolve into integrated planning that considers generation retirements, new resources, and load growth and develops coherent transmission plans.
- Exercise tools that ensure that the existing grid is being used as efficiently as possible: grid operators can incorporate higher-capacity conductors, dynamic line ratings, and other advanced transmission technologies to increase power flows over existing transmission lines, allowing existing generation to access more load and new generation to come online much more quickly. Using these technologies could double the amount of interconnection capacity in the wind-rich Great Plains alone.
- Bolster transmission planning by using long-term forward-looking scenario planning and incorporating forward-looking load growth: FERC is currently considering and should quickly finalize a strong rule that ensures that utilities undertake long-term planning that considers multiple scenarios—including a business-as-usual scenario to meet the

⁷² *Id.* at 44.

⁷³ *Id.* at 41.

expected future resource mix. But grid operators need not wait for FERC to act. They have existing tools and well-known practices to ensure robust transmission planning. Grid operators know what generation has requested to interconnect to the grid. While historically not all generation in the interconnection queue is built, grid operators can use probabilistic scenarios to plan for transmission to meet the needs of expected new generation. Study after study has also shown growth in electrification and other load changes, and grid operators must start incorporating these foreseeable changes into their transmission plans.

- Prioritize interregional transmission: Grid operators can also start planning for transmission between regions to bolster reliability, particularly in the face of increasing climate change-induced extreme weather events. Interregional transmission can provide access to a wide variety of resources to provide energy if and when the need arises, and geographical diversity to balance wind and solar resources to maintain reliability all year long. While FERC has asked questions about interregional transfer in an Advance Notice of Proposed Rulemaking and at a Workshop, grid operators do not have to and should not wait for FERC or congressional action to make progress on interregional transfer standards.

Brattle catalogs a series of reliability enhancements that ISOs/RTOs already have underway to better prepare for a highly renewable grid. *See* Table 1. This work has been started and can address any challenges associated with the ongoing energy transition and any modest increment spurred by this rulemaking. Brattle notes:

There is good reason for cautious optimism. These reforms have been designed to solve the coming reliability challenges, building off decades of categorically similar problems and solutions. They comprehensively cover every aspect of reliability. On the other hand, adapting to meet changing reliability needs is contingent on continued action from grid operators, utilities, regulators, and other stakeholders to develop and implement reforms.⁷⁴

⁷⁴ *Id.* at 27.

Table 1. ISOs/RTOs Pursuing Reliability Enhancements Suited to Renewable Deployment⁷⁵

	ERCOT	CAISO	MISO	PJM				
[A] Inverter –based resource integration studies & transition efforts	Impact of Growth in Wind and Solar on Net Load; Inverter-Based Resource Working Group	Reliability Standards to Address Inverter-Based Resources	RIIA, Reliability Attributes effort	Energy Transition series; 2014 Renewable Integration Study series				
Long-Term Adequacy Model [B] Includes all hours of year	N/A	Hourly ELCC for clean resource long-term adequacy values	Hourly ELCC for clean resource long-term adequacy values	Proposed comprehensive hourly construct				
[C] Accounts for extreme weather over decades	N/A	Yes for clean resources	Yes for clean resources	Proposed for all resources and overall capacity requirement				
[D] Accounts for extreme weather effects on availability	N/A	No, except for ELCC	No, except for ELCC	Proposed for all resources and overall capacity requirement				
Operational Energy Adequacy [E] Increased procurement of uncertainty reserves	Day-ahead non-spin reserve and online reserves	Day-ahead spinning and non-spinning reserves	No*	Synchronized, Primary, Secondary Reserves				
[F] New types of uncertainty reserves	ERCOT Contingency Reserve Service, Dispatchable Reliability Reserve Service (pending)	Flexible Ramping Product, Imbalance Reserve (proposed)	Short-Term Reserve, Ramp Capability Product	Secondary Reserves				
[G] 5-minute energy settlements	Yes	Yes	Yes	Yes				
[H] Improved day-ahead resource schedule optimization	No	Storage optimization, other day-ahead enhancements	No	No				
Operating Reliability [I] Ensuring voltage control	Yes	Yes	Yes	Yes				
[J] Ensuring frequency response	Require, monitor, & procure	Require, monitor, & procure	Require & monitor	Require & monitor				
[K] Ensuring other Essential Reliability Services	Monitor inertia, monitor & procure voltage disturbance performance	N/A	N/A	N/A				
[L] Percent energy from wind & solar	2012 9%	2022 31%	2012 6%	2022 26%	2012 7%	2022 16%	2012 2%	2022 5%

⁷⁵ Celebi et al., *supra* note 16, at 69.

EPA's proposed rule takes advantage of existing power sector trends to achieve emissions reductions without compromising reliability. FERC, the ISOs/RTOs, and utilities can and must do their part to address the reliability implications of the changing electricity grid, using both existing and new tools to prepare for the changes coming in the energy sector regardless of EPA action.

VI. EPA does not need to include an additional mechanism to address grid reliability in the final rule because the proposal already includes features and provisions that sufficiently provide such mechanisms.

As discussed above, the structure of the proposed rules addresses the first type of reliability concern (short-duration unpredictable events) with subcategories and annual averaging and helps address the second type of reliability concern by (a) providing long lead times for compliance, (b) adopting a subcategory system that permits sources to continue operating without new pollution controls at lower capacity factors well into the future, (c) providing state plan drafters with flexible options for achieving equivalent results, and (d) providing reliability authorities with additional transparency into retirement decisions and retrofit plans.

There is no need for additional reliability mechanisms, beyond the proposal's provisions, to maintain reliability through short-duration events. Most existing gas units that operate below the proposed rule's capacity threshold would have substantial room to ramp up their capacity utilization in such events. Even larger existing gas units or new units could run at very high capacity factors to respond to short-term events while on an annual average basis still staying below proposed thresholds for pollution standard coverage.⁷⁶ These existing mechanisms and flexibilities are sufficient to maintain reliability for these shorter events, obviating any additional dedicated reliability mechanism for those events. As discussed further below, for longer-duration events outside of the owner's or operator's control, increments of progress and milestones will provide sufficient advance notice such that, with a proper showing, states can revise their plans and provide extended compliance deadlines through the RULOF variance provisions.

If, however, EPA determines that it is necessary to include an additional mechanism beyond the variance process to address reliability concerns, it is critical that EPA avoid rewarding poor planning, disincentivizing deployment of greenhouse gas-reducing technologies and strategies, or creating perverse market signals that impede development of clean resources. EPA must instead ensure that such a mechanism is carefully applied with oversight and opportunity for public engagement (including judicial review) that is at least equal to that provided through the variance and plan revision process.

⁷⁶ CAELP, *Reliability: The Power of Averaging* [Infographic], <https://static1.squarespace.com/static/5a1aca61ccc5c5ef7b931da7/t/6544f09f616b42026d271bd0/1699016911357/reliability-power-of-averaging>.

A. The proposal includes mechanisms to ensure timely compliance and flexibility in the case of longer-lead-time events outside of the owner’s or operator’s control.

The proposed compliance timelines for baseload gas-fired EGUs or longer-term coal-fired EGUs are based on EPA’s analysis of how much time is needed to comply with standards of performance based on implementation of the different systems of emission reduction.⁷⁷ The compliance timeline accommodates steps such as planning, permitting, and constructing. The increments of progress and milestones, described above at Sec. IV D, ensure that sources are on a path to compliance and that any risks to achieving compliance are recognized early.

If an owner or operator has met all increments of progress within its control and can demonstrate delays beyond its control that imperil timely compliance, the existing variance process provides a means for the owner or operator to seek a state plan revision pursuant to proposed 40 C.F.R. § 60.5785b.

In these circumstances, and with the proper showing, states may consider using the RULOF variance mechanism to adjust the compliance deadline and remaining increments of progress or milestones for an affected EGU. The owner or operator must demonstrate fundamentally different factors specific to the facility that make compliance under the original timeline “physical[ly] impossib[le]” or that “make application of a less stringent ... final compliance time significantly more reasonable.”⁷⁸ This would require showing that the timelines, costs, or other assumptions underlying EPA’s determination of the best system of emission reduction, emission limit, and compliance date for the relevant subcategory are fundamentally different at the particular facility. For example, for a source retrofitting with CCS, if the availability of the pipeline necessary to take CO₂ to a sequestration site is delayed for reasons outside the control of the owner or operator or of state authorities, a case could be made that timely compliance is “physically impossible.”

Commenters agree with EPA that it is reasonable and necessary “to require affected EGUs and states to provide evidence that a source’s circumstances have in fact changed, in order for the EPA to approve a plan revision” and that the need for revision was “not caused by self-created impossibility.”⁷⁹ The owner or operator must therefore demonstrate that it has met the milestones and increments of progress within its control and that circumstances rendering timely compliance impossible are outside of its control. It must also show that the requested extension is as minimal as possible to ensure the standard reflects the best system. RULOF provisions should not be utilized to change subcategories or provide a less stringent standard (vs. an extended compliance deadline) upon showing of anything less than impossibility.

⁷⁷ Proposal at 33371.

⁷⁸ 40 C.F.R. § 60.24a(e).

⁷⁹ Proposal at 33404.

We emphasize that the response to delays outside the control of the EGU owner or operator (and the state) should be limited to compliance extensions, not a permanent weakening of emission limits. First, such an alternate standard would be inconsistent with the best system of emission reduction determination. No permanent weakening of emission limits would ever be justified to respond to a temporary problem, such as a delay in building out infrastructure. Nor should EPA permit sources to shift into a different subcategory with more lenient emissions limits or timetables. This would present the kind of “self-created impossibility” that EPA has warned against in the proposal. If the owner or operator demonstrates that “a source’s circumstances have in fact changed,”⁸⁰ those would be grounds for a variance rather than a shift in subcategories.

Commenters agree with EPA that “it would not be appropriate to request an [administrative compliance order] to address reliability risk and anticipated noncompliance in circumstances in which a state plan revision is possible.”⁸¹ The information disclosed pursuant to the requirements for increments of progress will in nearly all instances provide sufficient warning that the source is at serious risk of missing its compliance deadline for reasons outside its control. This will provide sufficient lead time for a source to apply for a RULOF variance, for a state to determine whether a variance is warranted, and to obtain EPA review of a state plan revision.

B. A reliability mechanism must not be applied on a system- or state-wide basis or on a subcategory basis.

As described above, the electric system is undergoing notable changes, leading to reduced emitting generation even under a future with no Section 111 GHG standard. Economic factors, magnified by the IRA, are already accelerating the shift to cleaner generation, reducing electricity costs, and lowering climate and air pollution.

Accordingly, states, utilities, FERC, and grid operators must be acting now to prepare the grid for reliable and safe operations under these conditions. This may include deploying advanced grid management technologies, revising market designs, increasing transmission capacity, speeding interconnection of new generation, and updating how capacity of both fossil and intermittent resources is accredited and accounted for. Importantly, all these actions must be undertaken regardless of whether or how any Section 111 standard is implemented.⁸²

Any reliability-based compliance extensions should be available only on a source-by-source basis. Extensions should not be granted across a grid region, state, or other system. This will ensure that any mechanism is narrowly focused on impacts that may be specific to a Section 111

⁸⁰ *Id.*

⁸¹ *Id.* at 33402.

⁸² Celebi et al., *supra* note 16.

standard, rather than inappropriately encompassing broader system-wide changes which grid operators must independently and concurrently manage.

Some commenters have proposed adopting a reliability subcategory that would establish distinct compliance requirements for units identified as important for reliability.⁸³ This approach raises legal and policy concerns that render it inappropriate and inadvisable.⁸⁴

The principal objection to a subcategory approach is that reliability issues are typically source-specific. They may relate to the source's physical location and the availability of alternate generation resources. Subcategories must be unified by some common element that renders the included sources of the same type, class, or size.⁸⁵ A generalized "need for reliability" is not a unifying element that properly defines a subcategory.

The impact, duration, and other specifics of these scenarios must be assessed on an individual basis and should not be grouped together under a subcategory with a uniform emissions standard. Possible source-specific issues include difficulty deploying control technology, failure to develop sufficient replacement generation, or severe transmission constraints. Even source-specific relief may be inappropriate without a compelling demonstration that the source owner or grid operator has explored the availability of substitute generation, alternatives to transmission, demand-response opportunities, or additional ways to meet demand. Lastly, as mentioned above, sources should not be permitted to move between subcategories. Relief for any reliability concerns should remain source-specific.

C. EPA must assure that any reliability mechanism includes ample oversight and opportunity for notice and comment.

The background regime for ensuring reliability plus the flexible features of the existing EPA proposal, including the variance provisions under Section 111(d), provide ample avenues to

⁸³ See, e.g., Joint ISO/RTO Comments, Docket No. EPA-HQ-OAR-2023-0072-0673 (proposing "the adoption of an additional sub-category that would accommodate units deemed needed for reliability, whether natural gas or coal. This subcategory would be populated with specific units or locations as identified by the ISO/RTO where unit retirement would cause significant reliability challenges...").

⁸⁴ Relatedly, EPA seeks comment on whether sources owned or operated by rural electric cooperatives or small utility distribution systems belong in a subcategory, which could address concerns about the cost or technical feasibility of deploying pollution controls on sources in remote locations (with implications for electric reliability in these areas). 88 Fed. Reg. 80683–84. As EPA notes, however, "exclusions or subcategories, if available, must be based on the class, type, or size of the sources and be consistent with the Clean Air Act." *Id.* at 80684. The mere fact that a source is owned or operated by a certain type of entity does not necessarily establish that the source itself is of a different class, type, or size that would warrant special treatment under the statute. Therefore, rather than establishing a subcategory or blanket exemption for sources owned by small businesses (or any other type of entity), the agency should allow states to accommodate sources that encounter difficulties in implementing controls because they are fundamentally different from the factors that EPA considered, through the standard RULOF process provided in Section 111(d) and EPA's regulations implementing that provision.

⁸⁵ 42 U.S.C § 7411(b)(2).

ensure that compliance with these standards preserves reliability. In particular, the variance provisions create a pathway for providing compliance extensions if it is demonstrated that a source cannot comply on the original schedule due to circumstances outside of the operator's control. For these reasons, there is no need or basis for EPA to establish any alternate or additional reliability process or mechanism for units to which the variance process applies.

If EPA, nonetheless, perceives a need for a reliability safety mechanism other than the variance procedure, it is essential to ensure substantive and procedural safeguards at least equivalent to those provided under that procedure. The necessary guardrails include: a transparent process that allows participation by all affected parties, clear criteria for demonstration of a reliability-related fundamental difference, and the opportunity for judicial review of any variances granted to such sources.

First, it is important that any request for a reliability-based compliance extension for such sources be conducted through a public process. EPA must require a clear demonstration of both the reliability issue and the steps already taken to ameliorate the issue. This is necessary to ensure that a reliability mechanism is only utilized in rare circumstances and when absolutely necessary, and not due to negligence or poor planning on the part of a source operator or grid manager.

As part of this demonstration, an existing source must document compliance with all prior milestones or increments of progress. The demonstration would also have to explain how the problem leading to the reliability issue could not have been anticipated, and that the owner or operator, in conjunction with the appropriate relevant balancing authority, RTO, or ISO took all reasonable steps to avoid and solve the problem. Finally, any request must include a clear plan and schedule for curing the problem on a reasonable timeline and in a way that minimizes both the magnitude and the duration of any operations that would fall outside of the otherwise applicable standard.

Second, any such process must include an opportunity for interested entities to provide analysis and feedback. No reliability extension should be considered unless the appropriate relevant balancing authority, RTO, or ISO provides compelling evidence that retaining the original compliance schedule would create a critical reliability problem and that no other supply- or demand-side measure is available to solve that problem. This analysis and attestation must be publicly available and reviewable. In addition, review and opportunity for comment must be conducted at both the federal and state level and noticed publicly in a manner providing a sufficient timeline for public engagement. EPA should not allow any mechanism that provides for automatic triggers or any action without public review. Finally, any such compliance extensions must include an opportunity for judicial review.

Respectfully Submitted,

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Ben Grove Carbon Storage Manager	
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List of Attachments

Attachment No.	Source
[1]	John ET Bistline, et al., Environmental Research Letters, <i>Power sector impacts of the Inflation Reduction Act of 2022</i> (2023), https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b/meta .
[2]	Metin Celebi and Andrew Levitt, et al., <i>Bulk System Reliability for Tomorrow’s Grid</i> (Dec. 20, 2023), https://www.brattle.com/wp-content/uploads/2023/12/Bulk-System-Reliability-for-Tomorrows-Grid_December-2023_Final.pdf .
[3]	Energy Innovation, <i>Maintaining A Reliable Grid Under EPA’s Proposed 111 Rules Restricting Power Plant Emissions</i> (Nov. 2023), https://energyinnovation.org/publication/maintaining-a-reliable-grid-under-epas-proposed-111-rules-restricting-power-plant-emissions/ .
[4]	ICF, <i>Review of Expected Resource Adequacy in PJM under Stress Conditions during Summer and Winter Peak Periods</i> (Nov. 9, 2023), https://www.nrdc.org/sites/default/files/2023-11/icf-caelp-nrdc-edf-peak-stress-resource-modeling-20231109.pdf .
[5]	ICF, <i>Review of Expected Resource Adequacy in PJM under Stress Conditions and High Demand during Summer and Winter Peak Periods</i> (Dec. 19, 2023), https://www.nrdc.org/sites/default/files/2023-12/pjm-peak-stress-resource-adequacy-review-icf-20231219.pdf .
[6]	Andover Technology Partners, <i>Compliance Options Available to Individual Power Plants Under the Proposed Clean Air Act Section 111 GHG Rules</i> (Dec. 18, 2023), https://www.andovertechnology.com/articles-archive/ .
[7]	Andover Technology Partners, <i>History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations</i> (Dec. 18, 2023), https://www.andovertechnology.com/articles-archive/ .
[8]	Carbon Solutions, <i>Power Sector Brief: Potential CO₂ Infrastructure and Costs Under a Preferred Regulatory Policy</i> (Dec. 2023).

Appendix A: Despite complaints that the 2015 Carbon Standards for new coal and gas plants would create reliability problems, EPA’s projections proved conservative, no such problems arose, and the rules functioned as a backstop for reasonable projections of ongoing trends

Eight years ago, EPA finalized standards for new coal plants based on partial CCS and NGCC technology for baseload gas plants which provide an instructive case study for the current rulemaking.⁸⁶ The standards apply to any power plant within those subcategories built after June 18, 2014. Despite industry protests that these standards would block new plant construction or curtail needed simple cycle generation and create reliability problems, no such problems have materialized. No power company has proposed to build a new coal plant, and power companies have been able to operate new gas plants in compliance with the 2015 standard.

In 2015, industry opponents to carbon standards made a similar claim as they do today: EPA’s projection of the source category trends are wrong or pose too much risk and therefore the standards will have more impact, including reliability issues, than the agency predicts. This section discusses EPA’s rationale for the 2015 rules; industry claims of reliability risks; and how reality bore out EPA’s predictions without any reliability problems.

In 2013, the power sector accounted for nearly 40 percent of all energy-related CO₂ emissions in the country and coal-fired plants made up over 75 percent of that contribution. Yet all relevant indicators foresaw no new coal plants due to low electricity demand growth, highly competitive natural gas prices, and increases in the supply of renewable energy. And as to gas-fired EGUs, NGCC technology was more fuel efficient, such that if a plant was running more than 20 percent of the time and burning more fuel, economics would dictate building the more efficient plant instead of a simple cycle plant. EPA correctly predicted that even under the most favorable circumstances, simple cycle plants would be running at very low capacity factors. Accordingly, EPA tailored standards to these expectations.

EPA’s 2015 analysis bore out and was even conservative: no new coal plants have been built, simple cycle gas plants run at very low capacity factors, and reliability has been maintained. The reliability arguments being made today regarding the May 2023 proposed standards resemble those made in 2015 and are no more likely to prove warranted.

VII. The 2015 Carbon Standards set CCS-based standards for new coal-fired power plants while recognizing that no new coal plants would be built.

In 2015, EPA set a standard for new coal-fired power plants based on partial carbon capture. The agency determined that no new coal-fired power plants were likely to be built regardless of the rule. Nonetheless, EPA recognized that some such sources might still be built for non-economic

⁸⁶ Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64509 (Oct. 23, 2015).

reasons (such as achieving or maintaining fuel diversity) and therefore adopted standards to ensure that emissions from any such plants would be well-controlled in the event they were built.

As seen in EPA’s 2015 table below, economics would dictate building a new gas-fired power plant instead of a coal-fired power plant given the choice between the two (just as economics make it currently unlikely that coal-fired plants operate beyond 2039 or that gas-fired plants run at baseload past 2034). In 2015, a new NGCC was 27 percent less expensive than an uncontrolled coal plant (levelized cost). *See* Figure 7. Yet, industry claimed that *this rule* was a bald attempt to “assure coal was ‘priced out of the market’ for the foreseeable future.”⁸⁷

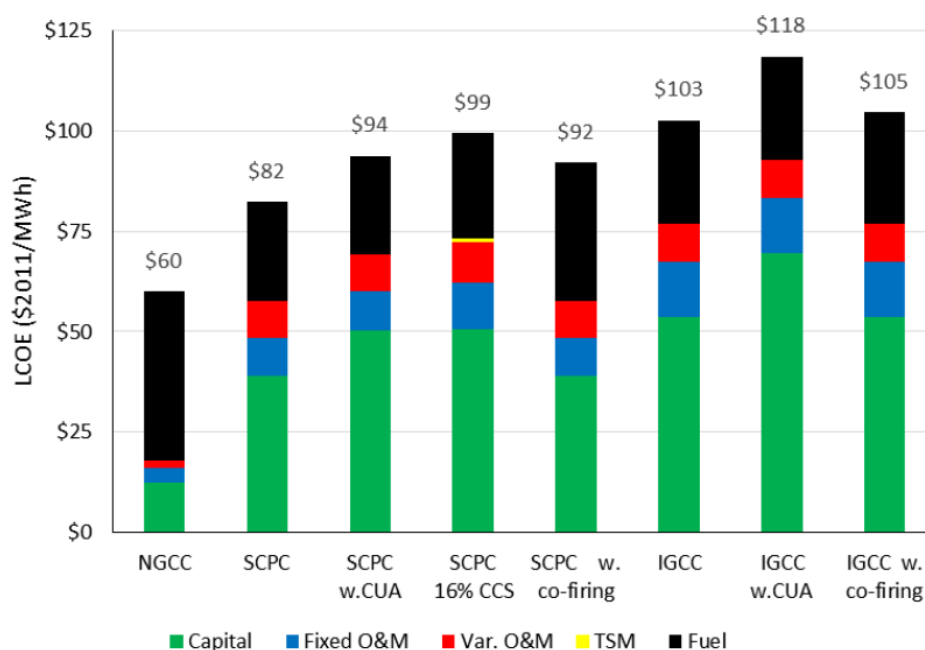


Figure 7. Illustrative Wholesale Levelized Cost of Electricity of Alternative New Generation Technologies by Cost Component⁸⁸

EPA determined that partial carbon capture was adequately demonstrated and cost-reasonable if any new coal plant was built. But because few if any power companies were expected to make

⁸⁷ Comments of Am. Elec. Power, Docket ID No. EPA-HQ-OAR-2013-0495-10618, at 48 (May 8, 2014) [hereinafter AEP 2015 Comments].

⁸⁸ EPA, *Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Units* 4-28 (Aug. 2015), <https://archive.epa.gov/epa/sites/production/files/2015-08/documents/cps-ria.pdf> [hereinafter EPA 2015 RIA].

the uneconomic decision to build a new coal plant instead of a new gas plant, the rule was not expected to have an impact on reliability.

Despite EPA’s determination that “even in the most favorable combination of regional variability in capital costs and delivered fuel prices ... are insufficient to support, new ... coal-fired capacity in the analysis period,⁸⁹ opponents of the rule claimed that the standards “favor[] natural gas generation over coal” and “creat[e] adverse consequences for ... reliability and affordability.”⁹⁰ Opponents characterized EPA’s analysis of the future trajectory of the sector as “extremely naive, devalu[ing] the benefits of energy diversity, ignor[ing] a long history of volatility in energy supply expectations, and [a]s complacent to the ever increasing challenges to the development of natural gas generating units.”⁹¹

Commenters further claimed that the ability to dispatch coal “is vitally important to maintaining a reliable and cost effective electricity supply when natural gas prices fluctuate,” which they asserted was “inevitable.”⁹² “Even if a resource is not currently seen as cost competitive, market conditions may change unexpectedly, either for the short- or long-term, making use of different resources necessary and/or desirable to provide reliable (and affordable) generation at different times.”⁹³ “[A]s the energy supply becomes more and more dependent on natural gas without an alternative in case of supply shortages or disruptions, it will become less certain that additional natural gas-fired capacity actually will meet the ‘basic demand for electricity’ reliably.”⁹⁴

Commenters also raised concerns that significant construction of additional natural gas infrastructure would be necessary and infeasible. “What is at issue here is whether this fuel is certain to be available at sites where new baseload generation may be needed to replace retiring coal-fired units or at new sites where new baseload generation is required for additional reliability purposes.”⁹⁵ “[H]aving a reliable and affordable natural gas supply at a given site where new base-load generation is needed likely presents transportation obstacles and

⁸⁹*Id.* at 4-29 to 4-34.

⁹⁰ Comments of Southern Co., Docket ID No. EPA-HQ-OAR-2013-0495-10095, at 1 (May 15, 2014) [hereinafter Southern Co. 2015 Comments].

⁹¹ AEP 2015 Comments, at 45.

⁹² Southern Co. 2015 Comments, at 6; *see also* Comments of DTE Energy, Docket ID No. EPA-HQ-OAR-2013-0495-10243, at 2 (May 9, 2014); Comments of Duke Energy Bus. Servs., Docket ID No. EPA-HQ-OAR-2013-049-9426, at 31–32 (May 9, 2014) [hereinafter Duke 2015 Comments].

⁹³ Comments of the Edison Elec. Inst., Docket ID No. EPA-HQ-OAR-2013-0495-9780, at 20 (May 9, 2014) [hereinafter EEI 2015 Comments].

⁹⁴ Comments of Utility Air Regulatory Group, Docket ID No. EPA-HQ-OAR-2013-0495-10938, at 83 (May 9, 2014).

⁹⁵ Comments of National Rural Electric Coop. Assn., Docket ID No. EPA-HQ-OAR-2013-0495-10952, at 13 (May 9, 2014) [hereinafter NRECA 2015 Comments].

unforeseen impediments outside the control EPA or any other regulatory body.”⁹⁶ Commenters envisioned further that:

numerous obstacles beyond the control of the pipeline builders could “delay or derail” efforts to meet these projected needs. Opposition by multiple stakeholders including landowners, environmental groups, and groups having competing interests as well as federal/state jurisdictional impediments well outside the control of EPA could delay significantly needed construction of additional pipelines. ...[A]dditional pipelines will be necessary to sustain grid reliability and provide electric service to consumers at a reasonable cost ...⁹⁷

Industry commenters were wrong about the need for new coal to maintain a reliable system. No new coal plants have been built since 2013, none are planned, and the power system has maintained reliability.⁹⁸ Even when the price of gas fluctuated wildly, existing coal plants were not available to fill in demand, due to factors such as low stockpiles, low coal production, rail fees, supply chain issues and inability to ramp easily.⁹⁹ Industry commenters were equally wrong about the ability to build gas plants and infrastructure. Since 2015, over 51 GW of NGCC plants have been built,¹⁰⁰ along with nearly 200,000 miles of gas pipeline.¹⁰¹ The system did undergo a massive transition from coal to gas but, despite claims to the contrary, sufficient replacement generation was developed to fill in for retiring coal units, and this replacement generation helped ensure reliability was maintained.¹⁰²

The chorus of industry commenters thrashing against the predictions underlying the 2015 standard for new coal plants is now protesting the current proposed standards for coal plants operating after 2040, even though coal plants are, for the most part, expected to retire before 2040 under business-as-usual conditions. As in 2015, today’s industry complaints understate the power of underlying economic trends and the tax incentives that are enhancing them, and understate their own capabilities. Those complaints are no more reason to weaken the current

⁹⁶ *Id.* at 15.

⁹⁷ *Id.* at 14.

⁹⁸ M. Tyson Brown, *Nearly a Quarter of the Operating U.S. Coal-Fired Fleet Schedule to Retire by 2029*, EIA (Nov. 7, 2022), <https://www.eia.gov/todayinenergy/detail.php?id=54559> (reporting the last large plant built was Sandy Creek Energy Station in Texas).

⁹⁹ Tyler Hodge, *U.S. Coal-Fired Generation Declining After Brief Rise Last Year*, EIA, (Oct. 27, 2022), <https://www.eia.gov/todayinenergy/detail.php?id=54419>; Benjamin Storrow, *Gas, A ‘Bridge Fuel,’ Dominates U.S. Power at Any Price*, E&E News (Sept. 20, 2022), <https://www.eenews.net/articles/gas-a-bridge-fuel-dominates-u-s-power-at-any-price/>.

¹⁰⁰ EIA, *Electric Power Monthly* at tbl. 6.2.C, Feb. 2016 and Feb. 2023, <https://www.eia.gov/electricity/monthly/>.

¹⁰¹ Bureau of Transportation Statistics, *U.S. Oil and Gas Pipeline Mileage*, <https://www.bts.gov/content/us-oil-and-gas-pipeline-mileage> (last visited Dec. 19, 2023) (via tbl. 1-10, total gas pipeline mileage excluding service pipeline).

¹⁰² *See generally* Tierney, *supra* note 19.

proposal than they were in 2015. Nor is the possibility of unpredicted obstacles over the coming decade and a half a reason to abandon or weaken the current proposal.

When modeling, utility planning documents, technology costs and reports all indicate that the sector can and is highly likely to end up with a particular mix, EPA would be unreasonable to ignore such evidence under a public health-protective, forward-looking, and technology-forcing statute. While the agency must ensure that standards are based on adequately demonstrated and cost reasonable controls, when considering energy and reliability concerns, it is highly relevant that the standards lead to very incremental changes under a broad range of assumptions. And standards based on such reasonable projections are all the more defensible given the availability of RULOF variances if unpredicted problems should arise for specific plants.

VIII. The 2015 Carbon Standards for new baseload gas plants require NGCC technology that would likely be installed for economic reasons.

The story for gas plants is similar to that for coal. In 2015, the Carbon Standards for baseload new gas-fired plants were finalized and based on efficient operation of NGCC technology. Whether the plant was baseload or non-baseload was determined by its capacity factor and ranged from 33–50 percent depending on the efficiency of the plant, with less efficient plants having a lower capacity factor requirement in order to remain in the non-baseload subcategory. Again, EPA determined that economics separate and apart from the rulemaking would govern. Simple cycle CTs were generally less expensive to build but also less fuel efficient than an NGCC, therefore if it operated more than 20 percent of the time, it would be more cost-effective to build an NGCC. *See* Figure 8. EPA determined that irrespective of the rule, simple cycle plants would remain in the non-baseload subcategory which was subject to very lenient standards. If a plant decided to run at baseload, the more efficient operating NGCC technology was adequately demonstrated, cost reasonable and reduced emissions.

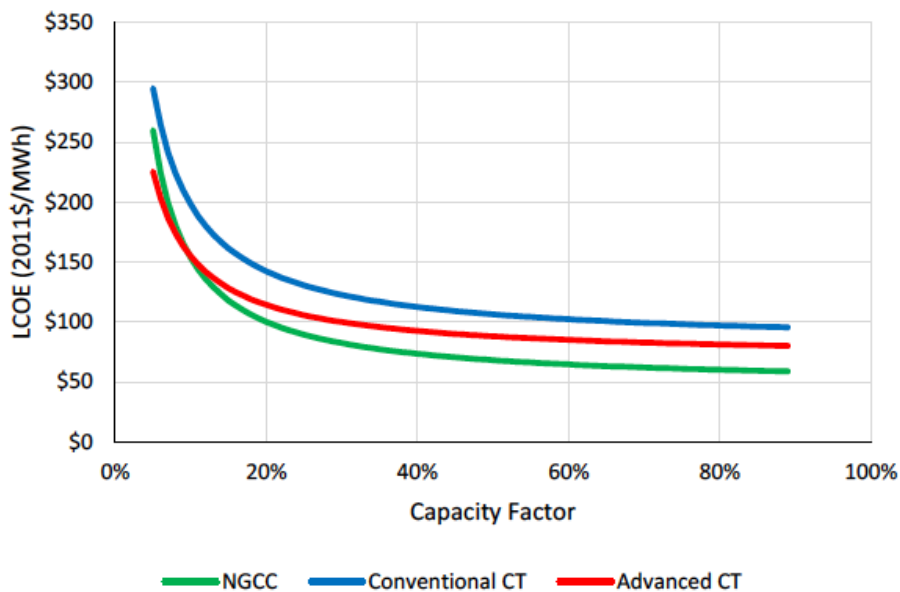


Figure 8. Levelized Cost of Electricity Across a Range of Capacity Factors, CT and NGCC (2011\$/MWh at \$6.07/MMBtu Levelized Natural Gas Price)¹⁰³

Nonetheless, opponents of the rule clamored for a complete exemption for all simple cycle turbines, claiming they would need the option of running at higher than a 33 percent capacity factor without installing combined cycle technology in order to maintain reliability: “Given the critical role simple-cycle turbines play in maintaining the reliability of the electric grid in this country, a role that cannot be met by NGCC units, an explicit exemption is the best approach to ensuring there are no unforeseen or unintended impacts to grid reliability from the rule.”¹⁰⁴ They claimed that “limiting operation of simple-cycle CTs jeopardizes grid reliability due to unforeseen circumstances” and that expansion of renewable generation will “require simple-cycle CTs to increase operations to maintain grid stability.”¹⁰⁵ In the alternative, they recommended allowing simple cycle turbines to operate up to 40 percent capacity factors.¹⁰⁶

While the National Rural Electric Cooperative Association (NRECA) agreed that it makes more economic sense to operate an NGCC at higher capacity factors, they made arguments similar to the ones we see in this docket, that other circumstances may dictate dispatch, such as “[t]ransmission constraints, unexpected outages of large baseload units, and increased renewable

¹⁰³ EPA 2015 RIA, *supra* note 888, at 4-35.

¹⁰⁴ Duke. 2015 Comments, at 44; *see also* EEI 2015 Comments, at 139-40; Southern Co. 2015 Comments, at 3; Comments of DTE Energy, Docket ID No. EPA-HQ-OAR-2013-0495-10243, at 8 (May 9, 2014) (same).

¹⁰⁵ Southern Co. 2015 Comments, at 56; EEI 2015 Comments, at 146.

¹⁰⁶ *Id.*

energy supplies...”¹⁰⁷ NRECA even claimed that “[i]n some situations” limiting simple cycle operation to a 33 percent capacity factor “would actually lead to less wind utilization, not more, and consequently more CO₂ emissions.”¹⁰⁸

Now in this docket, despite a plethora of evidence that the current existing gas fleet will be operating at low capacity factors in 2035, industry commenters claim that setting the applicability threshold for existing gas units at a 50 percent capacity factor will “limit[] their usefulness in responding to larger grid reliability and resilience needs.”¹⁰⁹ Similar to the 2015 arguments that limiting simple cycles to a 33 percent capacity factor would lead to increased emissions, industry commenters now claim that in the face of an increasing electricity load and the 50 percent applicability threshold proposed in this rule, electric companies will be forced to use other less efficient resources, which could result in an increase in emissions.¹¹⁰

Similarly, industry commenters argue that the low load subcategory for new gas units, consisting essentially of simple cycle CTs, should be increased from the 20 percent capacity factor to at least 25 percent to “allow these units to play the reliability critical role for which they are usually deployed” and integrate renewable resources.¹¹¹ However, as noted above, *in 2015*, EPA found it more cost effective to build an NGCC if the gas plant was going to operate more than 20 percent of the time and, since then, the simple cycle fleet has operated at 10–13 percent capacity factor on average,¹¹² and is projected to drop to operate at or below 2 percent annually by 2025 in Commenters’ baseline modeling. Further, renewable generation has grown 66 percent without needing simple cycles to run even close to a 33 percent capacity factor.¹¹³

Just like in 2015, all evidence points to this fleet running well below the applicability threshold irrespective of this rulemaking meaning this rule is not causing reliability problems.

IX. The power sector was undergoing a similar transition in 2015 as it is now, and EPA’s reasonable regulatory framework was successful and a should be built upon.

Every time a new pollution control requirement is proposed, opponents claim, despite all of the prior success at implementing the rules, reducing pollution, and maintaining reliability, that *this* time is different. Like now, however, in 2015, “[t]he electric sector [was] undergoing a period of

¹⁰⁷ NRECA 2015 Comments, at 24.

¹⁰⁸ *Id.* at 13.

¹⁰⁹ Comments of Edison Elec. Inst., Docket ID No. EPA-HQ-OAR-2023-0072-0772, at 43 (Aug. 8, 2023).

¹¹⁰ *Id.*

¹¹¹ *Id.* at 167.

¹¹² See EIA, *Electric Power Monthly*, Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, tbl. 6.07.A, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_07_a.

¹¹³ See EIA, *Electric Power Monthly*, Net Generation from Renewable Sources: Total (All Sectors), 2013-September 2023, tbl. 1.1.A, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_1_01_a.

intense change.”¹¹⁴ The sector was seeing a dramatic shift from coal to natural gas-powered electricity and significant increases in renewable generation.¹¹⁵ That rulemaking came in the wake of the shale fracking boom and gas prices had decreased dramatically and recently begun to stabilize and renewable energy incentives and state programs were leading to increased deployment.

EPA, however, was able to accurately predict industry trends and designed a reasonable rule that mimicked those trends and did not threaten reliability. Likewise, the current proposal builds a conservative baseline informed by a plethora of evidence and imposes the most stringent standards on those highly polluting sources that are likely not to operate due to factors external to the rulemaking. This design provides a critical backstop in terms of emissions without threatening reliability. This reasonable framework has encountered and overcome nearly identical criticism and is sure to do so again.

¹¹⁴ Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64509, 64524 (Oct. 23, 2015).

¹¹⁵ See generally Susan Tierney, Analysis Group, *The U.S. Coal Industry: Challenging Transitions in the 21st Century* (Sept. 26, 2016), <https://www.analysisgroup.com/globalassets/insights/publishing/2016-tierney-coal-industry-21st-century-challenges.pdf>.

Appendix B: Reliability Considerations for Sources that Choose to Comply with Emission Standards Via Installation and Operation of Post-Combustion Capture

As discussed in Commenters' August submission, post-combustion CCS is adequately demonstrated and cost reasonable, and sources can operate long-term and at baseload capacity if their emissions are commensurate with 90 percent CCS by 2030 or 2035 depending on subcategory. While compliance with the emissions standards will be measured at the stack, EPA has reasonably provided the time needed to install control technologies as well as that needed for supporting infrastructure such as pipelines and injection sites. The increments of progress associated with CCS in the proposal provide a framework for determining if sources are on track for compliance and, if necessary, the proposal provides for compliance flexibilities. Further, as explained in Sec. III of this appendix, there have been positive recent developments in the CCS infrastructure ecosystem, and that ecosystem continues to improve.

I. The proposal is designed to accommodate permitting, supply chain and infrastructure build out for the small number of plants expected to be subject to CCS-based standards.

With respect to the CCS-based standards, the proposed emission limits are structured to allow the necessary lead time for continued growth of the CCS industry, the issuance of the required permits for CCS pipelines, and the buildout of the necessary supply chain and infrastructure. Congress has invested in carbon management through billions of dollars in investments and loans for CCS projects and technology in the Infrastructure Investment and Jobs Act (IIJA)¹¹⁶ and tax credits in IRA.¹¹⁷ Together, these investments will continue to reduce the costs of applying CCS to power plants. Furthermore, EPA's adoption of the rule will help to build the market for CCS deployment, in a virtuous cycle that continues to improve the technology and infrastructure that can be used to meet the standards. Previous standards have had similar results. For example, in the earlier case of SO₂ emissions regulation, EPA noted that utilities had lacked a "profit incentive to develop and install"¹¹⁸ scrubber systems prior to its rulemaking, and that although the technology was available, commercial units were rare and there was only one U.S. vendor creating the scrubbers.¹¹⁹ EPA created the market demand for the technology by setting

¹¹⁶ Pub. L. No. 117-58, 135 Stat. 429 (2021)(this amount includes \$3.47 billion for carbon capture demonstration and pilot projects; \$2.1 billion in loans and grants for CO₂ transportation infrastructure, and \$2.5 billion for the commercialization of CO₂ storage projects); see Carbon Capture Coal., *Recently-enacted Infrastructure Investment and Jobs Act to Bolster Economywide Deployment of Carbon Management Technologies upon Full Implementation* (Jan. 21, 2022), <https://carboncapturecoalition.org/recently-enacted-infrastructure-investment-and-jobs-act-to-bolster-economywidedeployment-of-carbon-management-technologies-upon-full-implementation>.

¹¹⁷ Pub. L. No. 117-169, § 13701(a), 136 Stat. 1818, 1982 (2022).

¹¹⁸ EPA, *National Public Hearings on Power Plant Compliance with Sulfur Oxide Pollution Regulations*, at 8 (Jan. 1974), <https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=9101OYM8.txt>.

¹¹⁹ See Margaret R. Taylor, Edward S. Rubin & David A. Hounshell, *Regulation as the Mother of Innovation: The Case of SO₂ Control*, 27 U. Den. L. & Pol'y 348, 360 tbl. 2 (March 2005) (chronology of scrubber research, development, and design).

emissions standards in 1971, and within the following decade the number of scrubber vendors and units had dramatically increased.¹²⁰

The Clean Air Act’s design does not require sources to use the same technology as was designated the best system of emission reduction. After EPA sets an emissions limit based on the best system, “a source may achieve that emissions cap any way it chooses.”¹²¹ Here, there is no requirement for sources to rely on CCS, so long as they meet the standard. Modeling of the proposal, such as described in this section, estimates how many sources are likely to apply CCS to meet the standards (based on economic considerations) and what the corresponding infrastructure needs will be. Rigorous modeling estimates should not be confused, however, with overly simplistic projections based on rigid and unrealistic scenarios where the whole industry takes an inflexible path, ignores the proposal’s flexibilities and do not reflect likely or reasonable outcomes.¹²²

To examine the effects of a more protective, “Preferred Policy Case” scenario that Commenters discussed in greater detail in August comments on the proposal, the Center for Applied Environmental Law and Policy (CAELP) commissioned Carbon Solutions to model the potential buildout of CO₂ pipelines reflecting power sector modeling of that proposal.¹²³ CAELP reviewed the outputs of the IPM runs reflecting the Preferred Policy scenario estimating CCS deployed on coal steam and gas combined cycle facilities in each state and identified the specific real-world facilities that could be expected to install CCS to meet the projected capacity of CCS for each state. Carbon Solutions then ran its proprietary SimCCS model with these selected facilities as inputs, assuming full capture of CO₂ at each facility. The model then produced results in the form of kilometers of pipeline built, pipeline routes, injection sites and capture, transport, and storage costs.

In the Preferred Policy Case in SimCCS, 62 facilities are estimated to deploy CCS nationally to comply with the rules, capturing about 118 million metric tonnes of CO₂ per year. That CO₂ is then transported through approximately 2,613 km of pipeline to 27 sinks (storage sites)—a total length of pipeline that is eminently reasonable in light of historical levels of deployment of other types of pipelines.¹²⁴ The total cost per tonne of deploying CCS on these sources amounts to

¹²⁰ See Press Release, EPA, EPA Says Scrubbers Necessary for Health Protection Under Coal Conversion Plan (July 14, 1977), <https://www.epa.gov/archive/epa/aboutepa/epa-says-scrubbers-necessary-health-protection-under-coal-conversion-plan.html>.

¹²¹ *West Virginia*, 142 S. Ct. at 2601.

¹²² See Amanda Levin, *Unrealistic Assumptions Yield Unrealistic Results*, NRDC (Nov. 2, 2023), <https://www.nrdc.org/bio/amanda-levin/unrealistic-assumptions-lead-unrealistic-results>.

¹²³ Carbon Solutions, *Power Sector Brief: Potential CO₂ Infrastructure and Costs Under a Preferred Regulatory Policy* (Dec. 2023) (Attach. 8).

¹²⁴ See DOE, *Carbon Capture, Transport, & Storage: Supply Chain Deep Dive Assessment* at 43-44 (2022), <https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final%202.25.25.pdf>.

\$54.65. This value is also well below the tax credit available under section 45Q¹²⁵ and the updated social cost of carbon.¹²⁶ A potential pipeline network is depicted below—mainly to illustrate the limited extent of pipeline footprint, as actual pipeline routes would be determined through community input, among other factors.

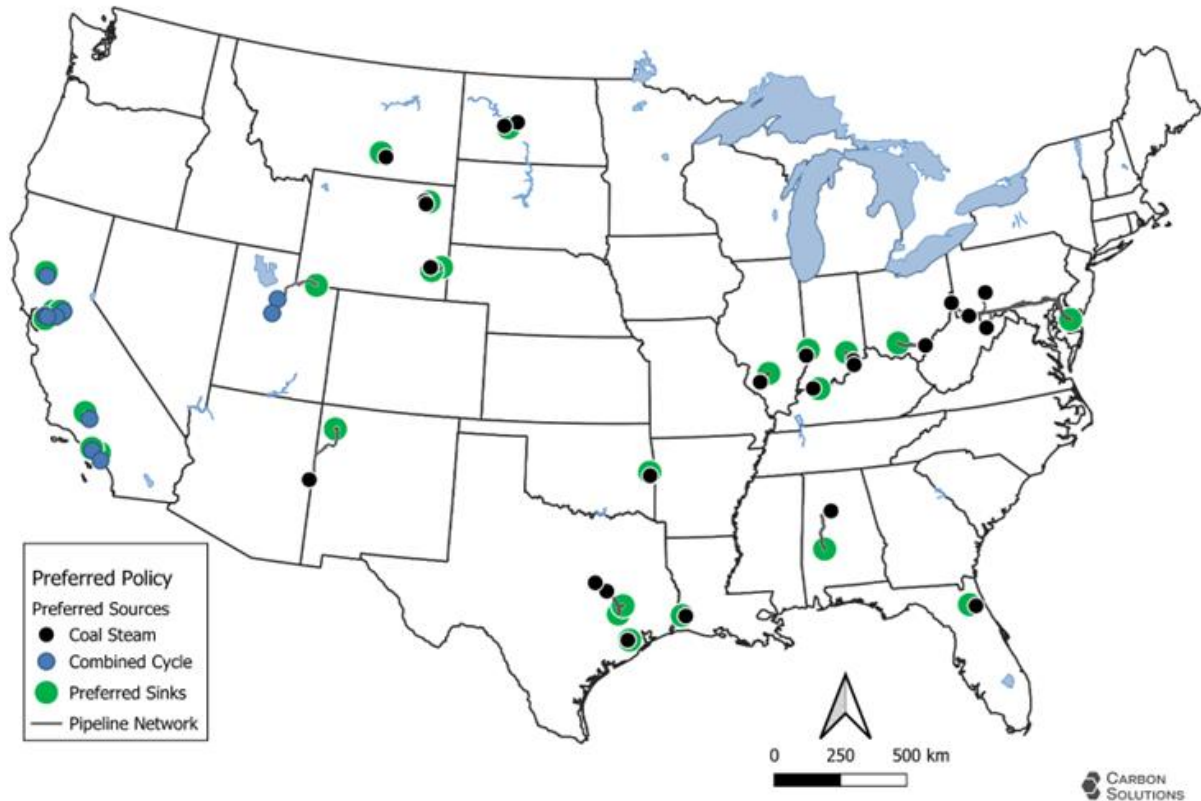


Figure 9: Preferred Policy Case Results: This scenario captures ~118 Mt CO₂/yr., at an average cost of \$54.65/tCO₂ and captures CO₂ from 62 separate streams¹²⁷

Aside from long lead times and the compliance flexibilities discussed elsewhere in the main text of this comment¹²⁸ that reduce the need for and smooth the deployment of CCS, the cooperative

¹²⁵ See 26 U.S.C. § 45Q (e.g., \$85 per ton for geologic storage of post-combustion CO₂ capture fulfilling certain conditions).

¹²⁶ See EPA, Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (Nov. 2023).

¹²⁷ Carbon Solutions, *supra* note 123, at 6.

¹²⁸ See *supra* Parts IV & V.

federalism structure of Section 111(d) further facilitates implementation of controls by involving relevant state permitting authorities in plan development. As Commenters noted in main text of the comment, it would be advisable for EPA to include a requirement for state agencies to consult with public utility commissions (PUCs) in devising state plans.¹²⁹ Those PUCs (or similar regulatory bodies) are most likely to be responsible for approving CO₂ pipeline siting and operations in the future, according to a survey of the current regulatory landscape recently published by the National Association of Regulatory Utility Commissioners.¹³⁰ In the few instances where PUCs are not clearly responsible for overseeing CO₂ pipeline development, the environmental agency itself is in charge (as in Louisiana), the PUC may take charge under broader authorities until specific legislation regarding CO₂ pipelines can be adopted (as in Minnesota), or there are simply few barriers to pipeline development (as in Texas). Although PUCs would not necessarily apply pipeline permitting and siting criteria during state plan consultations in a rigorous way, it seems unlikely that a PUC would interfere with pipeline development (along a safe and appropriate route) by a source that is assigned a CCS-based standard through a planning process in which the PUC was involved. On the contrary, it would be logical for the PUC to consider, at a high level, the potential for CO₂ pipeline siting and permitting when consulting with the air agency about CCS-based standards.

This discussion of infrastructure deployment for compliance should be placed within the context of what the proposal requires. To reiterate a point in our earlier comments,¹³¹ EPA determined that the best system of emission reduction for some sources is post-combustion capture. Compliance with that emissions limitation is demonstrated at the stack. Regulated sources' obligation under the proposal is only to comply with pre-existing EPA GHG reporting requirements, to transfer the captured CO₂ to an entity that complies with such reporting requirements, or to transfer it to another entity that will store the captured CO₂.¹³² This requirement helps ensure that the CO₂ will not reenter the atmosphere and thereby render EPA's emission limitation ineffective in actually reducing emissions to the air. Other state and federal authorities properly regulate the management of the CO₂ downstream.¹³³ The lead time for infrastructure deployment ultimately is to allow for demonstration of compliance at the stack.

¹²⁹ See *supra* Section IV. C.

¹³⁰ See Nat'l Ass'n of Reg. Util. Comm'rs, Onshore U.S. Carbon Pipeline Deployment: Siting, Safety, and Regulation, App. A (June 2023), <https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E>.

¹³¹ See Joint Comments, at 32.

¹³² See Proposal at 33328; proposed 40 C.F.R. §§ 60.5860b(f), 60.5555(f), 60.5555a(f). Regulated entities may also transfer captured CO₂ to a recipient that will store the CO₂ in another way that is at least as effective as geologic sequestration, under e.g., proposed § 60.5555a(g).

¹³³ See, e.g., Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO₂) Streams in Geologic Sequestration Activities, 79 Fed. Reg. 350 (Jan. 3, 2014).

II. The proposal’s increments of progress allow for early identification of whether a source may require a state plan revision because it is unable to meet its standard by the relevant deadline due to actions outside of its control.

As discussed in the main comment, the proposal includes increments of progress that state plans must include as enforceable elements.¹³⁴ These increments of progress require steps that a source that has chosen to comply with its standards based on installation of post-combustion capture must take, including final compliance with the relevant standard of performance. The increments of progress are designed to “ensure timely completion of pipeline infrastructure and ... timely selection of an appropriate sequestration site.”¹³⁵ Among the increments of progress are actions entirely within the control of a plant, such as awarding contracts for emissions control systems, and actions that rely on third party actors that must be reported, such as lists of pipeline-related permitting applications. As described in the main text of the comment, the increments of progress should provide sufficient advance warning if a source is not going to meet its compliance deadline such that it can seek and obtain a timely state plan revision.¹³⁶ This section provides CCS-specific information on the proposal’s increments of progress and associated timelines, and it also recommends additional information that may assist in these considerations.

Affected EGUs will be better positioned to meet increments of progress through adequate planning and concurrent action in anticipation of the final state plan. For example, a front-end engineering and design (FEED) study needed for the final control plan can take up to two years to complete, and this process can occur well before state plans are finalized. Milestones for the two additional increments of progress, such as documentation of pipeline-related permit applications and a CO₂ storage analysis report, can be achieved simultaneously along with the five generic increments.

EPA should consider additional elements to strengthen the criteria by which to measure the progress of impacted EGUs in order to ensure adequate preparation for CCS deployment and to identify where state plan revisions may be appropriate due to circumstances beyond the source’s control. For increment of progress (1), in addition to the submission of a final control plan, EGUs that plan to comply by implementing CCS should submit documentation of relevant permits and an estimated timeline for permitting decisions. This would allow for more adequate timing to deal with potential permitting setbacks and initiate a track record of permit-related actions over which EGUs have control. For increment of progress (2), EPA should require a procurement or purchase schedule to provide evidence that there is a sufficient plan to acquire the necessary components and equipment as well as alternatives. At this stage, EGUs should also be in a position to submit a detailed engineering design. For increment of progress (3), EGUs

¹³⁴ See *supra* Section VI. A; Proposal at 33389.

¹³⁵ Proposal at 33389.

¹³⁶ See *supra* Section VI. A.

should have acquired the necessary permits to begin construction and provide a construction schedule that outlines project deliverables and cost allocation.

Table 2. Recommendations for CCS Increments of Progress.

Increments of Progress – CCS Adoption	Proposed Milestones	Additional Milestones	Duration	Expected Deadline*
(1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency.	Final Control Plan Feasibility Study FEED Study	Permit Applications and Status Permitting Timeline	18–24 months	2026 / 2031
(2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.	Contract Awards Purchasing Receipts	Procurement Schedule Detailed Engineering	6–9 months	2027 / 2032
(3) Initiation of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CO ₂ capture on an annual basis.	Proof of Onsite Construction/ Installation	Permits Construction Schedule	6 months	2027– 2028 / 2032–2033
(4) Completion of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CO ₂ capture on an annual basis.	Completed Construction		24–36 months	2029 / 2034

Increments of Progress – CCS Adoption	Proposed Milestones	Additional Milestones	Duration	Expected Deadline*
(5) Affected EGUs using CCS to comply with their standards of performance would be required to demonstrate that all permitting actions related to pipeline construction have commenced by a date specified in the State plan.	Planning and Design Documentation List of Pipeline-Related Permitting Applications List of Relevant Authorities Permitting Timeline	Pipeline Construction Timeline	36–54 months	2028–2029 / 2033–2034
(6) Affected EGUs within this subcategory must submit a report identifying the geographic location where CO ₂ will be injected underground, how the CO ₂ will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities.	Storage and Transport pre-FEED studies Regulatory Requirements for Sequestration Activities Permitting Timeline	Preliminary geologic static earth model Preliminary geologic inputs for Class VI application	6–9 months	2026–2027 / 2031–2032
(7) Final compliance with the standard of performance by January 1, 2030 for coal-fired steam generating units and by January 1, 2035 for combustion turbine EGUs.		Monitoring, Reporting and Verification plan	6–12 months	2030 / 2035

III. The ecosystem for CCS deployment continues to improve.

EPA was reasonable in its conclusion that the 2035 emission limit for new baseload gas plants, and large baseload existing gas plants, and the 2030 emission limit for coal plants without a retirement date before 2040 are achievable. Post-combustion capture, sequestration, and storage are adequately demonstrated and cost reasonable and represent the best system of emission reduction for these subcategories, and the ecosystem for CCS deployment is continuing to improve. EPA was therefore reasonable in its assessment that the standards are achievable by those compliance dates.

EPA can be confident that the infrastructure needed for CCS deployment, including CO₂ pipelines and secure geologic storage sites, will expand to facilitate compliance with the proposal. To assess future infrastructure growth, EPA can rely on a wide range of indicators, including filed permit applications, announced projects, federal funding support for CCS, new laws that enable CCS deployment, and new technology announcements.

The cancellation of some infrastructure projects, such as a recent pipeline for CO₂ to be captured from ethanol plants,¹³⁷ does not call EPA's assessment into question. Cancellation of announced infrastructure projects is normal. For example, data on electric transmission infrastructure projects across North America obtained from the C Three Group, an energy infrastructure and utility market research and consulting firm, suggests that over 15 percent of transmission projects since the early 2000's have been canceled or withdrawn.¹³⁸ Of the projects in that dataset, 60 percent of projects are operating, and 64 percent are labeled as either operating or under construction. Most of the remaining 20 percent are in some form of development pre-construction. This comparison to transmission demonstrates that infrastructure buildout in a sector is often accompanied by cancellation of individual projects, and anecdotal information on the prospects for individual projects may obscure broader industry trends. This section describes broader industry trends and recent developments in the CCS ecosystem since our original comments submitted in August 2023.

A. Saline Storage Indicators

Class VI geologic storage permits are a key indicator of CCS interest. Since the passage of IJA and IRA the number of applications for Class VI saline storage permits has ballooned. In 2021,

¹³⁷ See Leah Douglas, *US carbon capture pipeline setbacks reflect challenges in climate fight*, Reuters (Sept. 28, 2023), <https://www.reuters.com/sustainability/us-carbon-capture-pipeline-setbacks-reflect-challenges-climate-fight-2023-09-28/>.

¹³⁸ See The C Three Group, (this dataset provides a comprehensive catalog of nearly 38,000 electricity transmission projects since the early 2000s with information on their ownership, location, development status, voltage, project drivers, and other technical information) <https://www.cthree.net/>.

only 15 class VI permits had been filed with EPA or states with primacy. Today, the pending permit applications has grown by 10-fold to 117 permits as shown in Figure 10.

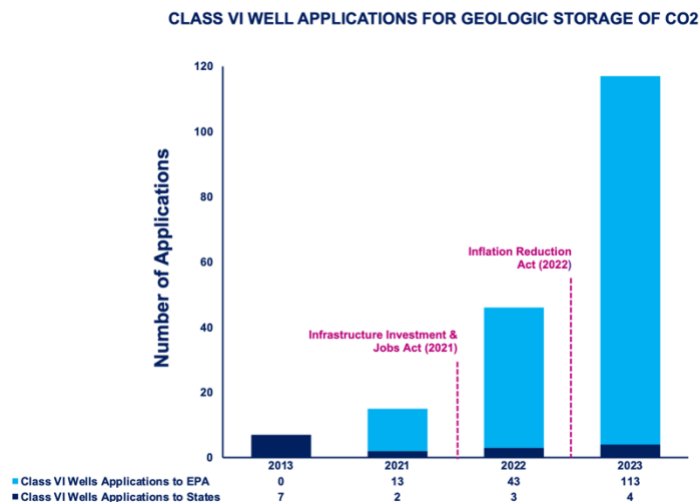


Figure 10. Class VI Well Applications for Geological Storage of CO₂.¹³⁹

Congress has invested in EPA’s processing of these well applications. The IIJA increased funding for Class VI injection well permitting by \$25 million total between FY22 and FY26.¹⁴⁰ These funds have supported additional full-time federal employees working on permit applications from just a handful to 25, distributed both at the national headquarters and at regional offices.¹⁴¹ EPA officials have committed to reviewing Class VI permits pending before them “as expeditiously as possible.”¹⁴² Although more can be done, these actions indicate EPA’s commitment to promptly processing Class VI permit applications.

Offshore storage interest is also growing. Since August 2023, the Texas General Land office issued six offshore CO₂ storage leases that will generate \$130 million in signing bonuses for Texas’s Permanent School Fund (PSF). Over the 30-year lease term, the PSF will receive an

¹³⁹ Sam Bowers, *The Pore Space Race: Why the rapid development of geologic carbon storage is good for the climate*, Clean Air Task Force (Dec. 12, 2023), <https://www.catf.us/2023/12/pore-space-race-rapid-development-geologic-carbon-storage-good-climate/>

¹⁴⁰ Infrastructure and Investment Jobs Act, Pub. L. No. 117-58, § 40306, 135 Stat. 429, 1002 (2021).

¹⁴¹ *Hearing to Examine Opportunities and Challenges in Deploying CCUS and DAC Technologies on Federal and Non-Federal Lands Before the S. Comm. on Energy & Nat. Res.*, 118th Cong. 4 (2023) (statement of Bruno Pigott, Principal Deputy Assistant Administrator for Water, EPA), <https://www.epa.gov/system/files/documents/2023-11/testimony-pigott-senr-hearing-nov-2-2023-cleared.pdf>.

¹⁴² *Id.* at 3.

estimated \$10 billion.¹⁴³ In Louisiana, the Commonwealth liquified natural gas site entered into a 20-year agreement to store CO₂ below 24,000 offshore acres near Cameron Parish with a capacity of more than 250 million metric tons.¹⁴⁴ Companies are also developing tools to help clients choose storage sites in the Gulf of Mexico.¹⁴⁵

New onshore storage projects in Texas are also progressing. Milestone Carbon leased 22,000 acres in West Texas for saline storage.¹⁴⁶ Last March, Chevron announced a 100,000-acre storage project on shore in the Texas counties of Chambers and Jefferson.¹⁴⁷ Since August, partners in that project have expanded to include Equinor.¹⁴⁸

B. New Project Indicators

Across the world, CCS project interest is growing. The Global Status of CCS Report 2023 shows a 48 percent increase in all CCS projects compared to 2022, including 198 new projects under development.¹⁴⁹ Meanwhile, BloombergNEF recently released its CCUS Market Outlook 2023, subtitled “Announced Capacity Soars by 50%.”¹⁵⁰ The report indicates that “there have been more project announcements in the past two years than ever before, mainly driven by favorable

¹⁴³ See Press Release, Tex. Gen. Land Off., Commissioner Buckingham Secures \$10 Billion for Texas Students with Historic State Land Carbon Capture and Storage Leases (Aug. 22, 2023), <https://www.glo.texas.gov/the-glo/news/press-releases/2023/august/commissioner-buckingham-secures-10-billion-for-texas-students-with-historic-state-land-carbon-capture-and-storage-leases.html>; Amal Ahmed, *As federal money flows to carbon capture and storage, Texas bets on an undersea bonanza*, Texas Trib. (Sept. 20, 2023), <https://www.texastribune.org/2023/09/20/texas-carbon-capture-storage-gulf-of-mexico/>.

¹⁴⁴ See Rocky Teodoro, *Commonwealth to Tap Onstream CO₂ for CCS at LNG Facility*, Rigzone (Nov. 30, 2023), <https://www.rigzone.com/news/commonwealth-to-tap-onstream-co2-for-ccs-at-lng-facility-30-nov-2023-174894-article/>; Carlos Anchondo, *Companies ink deal for CCS storage hub in Gulf of Mexico*, E&E News (Sept. 25, 2023), <https://subscriber.politicopro.com/article/eenews/2023/09/25/companies-ink-deal-for-ccs-storage-hub-in-gulf-of-mexico-00117666>.

¹⁴⁵ See Press Release, CGG, CGG Releases New GeoVerse Carbon Storage Study for Gulf of Mexico (Oct. 3, 2023), <https://www.cgg.com/newsroom/press-release/cgg-releases-new-geoverse-carbon-storage-study-gulf-mexico>.

¹⁴⁶ See Amanda Drane, *Houston's Milestone grows West Texas carbon storage hub with lease of 22,000 acres*, Hous. Chron. (Oct. 20, 2023), <https://www.houstonchronicle.com/business/energy/article/milestone-hub-new-carbon-capture-storage-permian-18437726.php>; *Milestone Carbon leases land for Permian Basin hub*, Carbon Capture J. (Oct. 22, 2023), <https://www.carboncapturejournal.com/news/milestone-carbon-leases-land-for-permian-basin-hub/5814.aspx?Category=all>.

¹⁴⁷ See Press Release, Chevron, Bayou Bend expands carbon capture project to onshore Southeast Texas (Mar. 6, 2023), <https://www.chevron.com/newsroom/2023/q1/bayou-bend-expands-carbon-capture-project-to-onshore-southeast-texas>.

¹⁴⁸ See Carolyn Davis, *Equinor Builds in U.S. by Joining Chevron, Talos in Texas Carbon Capture Project*, Nat. Gas Intelligence (Sept. 5, 2023), <https://www.naturalgasintel.com/equinor-builds-in-u-s-by-joining-chevron-talos-in-texas-carbon-capture-project/>.

¹⁴⁹ See Global CCS Inst., *Global Status of CCS Report 2023*, <https://status23.globalccsinstitute.com/>.

¹⁵⁰ Brenna Casey, *CCUS Market Outlook 2023: Announced Capacity Soars by 50%*, BloombergNEF (Nov. 9, 2023), <https://about.bnef.com/blog/ccus-market-outlook-2023-announced-capacity-soars-by-50/>.

policy and corporate net-zero goals.”¹⁵¹ They estimate that annual capture capacity could increase more than 740 percent by 2035. In the United States since August 2023, the Tennessee Valley Authority announced two FEED studies for carbon capture on natural gas-fired power plants in Mississippi and Kentucky. According to a trade publication, these studies focus on the 705 MW Ackerman and the 1,000 MW Paradise combined cycle plants.¹⁵²

This fall, CapturePoint announced new customers for their Louisiana CO₂ storage and pipeline projects.¹⁵³ Tallgrass announced in September that FERC had approved plans to convert a 400-mile natural gas pipeline to CO₂ transport.¹⁵⁴ In Central Illinois, a local zoning board recommended approval of a permit to drill a CO₂ well.¹⁵⁵

The Department of Energy (DOE) also continues to expand its data resources for the CCS community, including the development of the forthcoming Energy Data eXchange (EDX) DisCO₂ver platform, which connects stakeholders across commercial, regulatory, and research domains to a curated collection of CCS data, models, and capabilities. Among the tools contained in EDX DisCO₂ver platform is the CCS Pipeline Route Planning Database, which provides a curated compilation of critical decision factors, such as slope, existing infrastructure, and ground cover that provide planners with information about areas that are favorable for pipeline routing.¹⁵⁶

Other organizations have released proposals to speed the development of projects through permitting reform or principles to help companies develop community outreach plans.¹⁵⁷

¹⁵¹ *Id.* at 3.

¹⁵² See Power Eng’ring Int’l, *TVA to study carbon capture at two natural gas-fired plants* (Sept. 15, 2023), <https://www.powerengineeringint.com/gas-oil-fired/emissions-control/tva-to-study-carbon-capture-at-two-natural-gas-fired-plants/>.

¹⁵³ See Press Release, CapturePoint, *CapturePoint secures dedication of CO₂ for CENLA Hub from Southwestern Energy Company* (Nov. 15, 2023), <https://www.capturepointllc.com/news/capturepoint-secures-dedication-co2-cenla-hub-southwestern-energy-company>.

¹⁵⁴ See Sasha Ranevska, *Trailblazer Pipeline Company Approved for CO₂ Transportation*, Carbon Herald (Nov. 1, 2023), <https://carbonherald.com/trailblazer-pipeline-company-approved-for-co2-transportation/>.

¹⁵⁵ See Lyndsay Jones, *Permit for CO₂ wells in eastern McLean County to go before full board* (Dec. 6, 2023), <https://www.wglr.org/local-news/2023-12-06/permit-for-co2-wells-in-eastern-mclean-county-to-go-before-full-board>.

¹⁵⁶ See Nat’l Energy Tech. Lab., *NETL Develops Pipeline Route Planning Database To Guide CO₂ Transport Decisions* (May 31, 2023), <https://netl.doe.gov/node/12580>.

¹⁵⁷ See, e.g., Global CCS Inst., *Scaling up CO₂ Pipeline Deployment in the U.S. – Findings from Listening Sessions Hosted by the Global CCS Institute* (May 18, 2023), <https://www.globalccsinstitute.com/news-media/insights/scaling-up-co2-pipeline-deployment-in-the-u-s-findings-from-listening-sessions-hosted-by-the-global-ccs-institute/>; Carbon Capture Coal., *Carbon Capture Coalition Develops Guiding Principles to Improve the Permitting System for Carbon Management Infrastructure* (Nov. 16, 2023), https://carboncapturecoalition.org/carbon-capture-coalition-develops-guiding-principles-to-improve-the-permitting-system-for-carbon-management-infrastructure/?mc_cid=489058d4f3&mc_eid=b3dae62d2b.

Companies have also announced investments in new technologies associated with CCS. Archrock announced investment in Iona, a new capture technology.¹⁵⁸ Grey Rock announced investments in a company to develop CCS projects.¹⁵⁹

In October, the DOE announced the selection of seven Regional Clean Hydrogen Hubs using \$7 billion from the IIJA.¹⁶⁰ CCS is among the technologies that will be used to generate hydrogen at these hubs.

C. Government Policy Indicators

State and federal CCS efforts have also progressed since August 2023. For instance, in Michigan, the legislature adopted a new state law to require that 100 percent of each electric provider's total retail electric sales consist of clean or renewable energy by 2040.¹⁶¹ This legislation specifically calls out the allowance of carbon capture on natural gas power plants as an allowable clean energy system to count towards the 100 percent clean energy requirements. The law requires a 90 percent capture rate on natural gas power plants, but allows the Department of Environment, Great Lakes, and Energy to determine through a facility-specific major source permitting analysis that a capture rate higher than 90 percent meets the best available control technology standard; therefore, allowing for the option to require that a capture rate higher than 90 percent be used for individual permitted facilities in the future.¹⁶²

At the federal level, DOE has announced \$27 million to fund CO₂ transportation networks,¹⁶³ \$444 million for storage projects,¹⁶⁴ and progress on implementing the Carbon Dioxide

¹⁵⁸ See Press Release, Archrock to Partner with Ionada on Carbon Capture (Nov. 30, 2023), <https://markets.businessinsider.com/news/stocks/archrock-to-partner-with-ionada-on-carbon-capture-1032861799>.

¹⁵⁹ See Press Release, Grey Rock Forms Partnership With CarbonCycle to Grow Their Carbon Capture and Sequestration Platform (Oct. 3, 2023), <https://www.businesswire.com/news/home/20231003861148/en/>.

¹⁶⁰ See Press Release, DOE, Biden-Harris Administration Announces \$7 Billion For America's First Clean Hydrogen Hubs, Driving Clean Manufacturing and Delivering New Economic Opportunities Nationwide (Oct. 13, 2023), <https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving>.

¹⁶¹ See 2023 Mich. Pub. Acts 271, <https://www.legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0235.pdf>.

¹⁶² See *id.* § 3(i).

¹⁶³ See Press Release, DOE, DOE Announces \$27 Million for Carbon Dioxide Transport Networks to Manage Carbon Emissions (Sept. 15, 2023), <https://www.energy.gov/fecm/articles/doe-announces-27-million-carbon-dioxide-transport-networks-manage-carbon-emissions>.

¹⁶⁴ See Press Release, DOE, Biden-Harris Administration Invests \$444 Million to Strengthen America's Infrastructure for Permanent Safe Storage of Carbon Dioxide Pollution (Nov. 14, 2023), <https://www.energy.gov/articles/biden-harris-administration-invests-444-million-strengthen-americas-infrastructure>.

Transportation Infrastructure Finance and Innovation Act, which is part of the IIJA.¹⁶⁵ DOE also recently announced up to \$890 million in funding from the IIJA for three CCS projects.¹⁶⁶ Including advance appropriations, the Congressional Budget Office tallies over \$8 billion in federal funding for CCS programs under the IIJA from 2022 to 2026, as noted in the table below.¹⁶⁷

Annual Funding for CCS Programs in the Infrastructure Investment and Jobs Act, 2022 to 2026

Millions of Dollars

	2022	2023	2024	2025	2026	Total, 2022-2026
Funding for Programs Authorized Before the IIJA						
Large-scale pilot projects	387	200	200	150	0	937
Demonstration projects	937	500	500	600	0	2,537
Front-end engineering and design ^a	20	20	20	20	20	100
Subtotal	1,344	720	720	770	20	3,574
Funding for New Programs Authorized by the IIJA						
CIFIA program	3	2,097	0	0	0	2,100
Large-scale storage validation and testing	500	500	500	500	500	2,500
Subtotal	503	2,597	500	500	500	4,600
Total Funding	1,847	3,317	1,220	1,270	520	8,174

Data source: Congressional Budget Office, using data from the Infrastructure Investment and Jobs Act (Public Law 117-58), division J—Appropriations. See www.cbo.gov/publication/59345#data.

Funding shown here for 2023 to 2026 is advance appropriations; for all programs, those amounts remain available until expended.

CCS = carbon capture and storage; CIFIA = Carbon Dioxide Transportation Infrastructure Finance and Innovation Act; IIJA = Infrastructure Investment and Jobs Act.

a. The front-end engineering and design phase of a project is intended to produce engineering documents and cost estimates that will support an eventual investment decision.

¹⁶⁵ See DOE Loan Program Off., *Carbon Dioxide Transportation Infrastructure*, <https://www.energy.gov/lpo/carbon-dioxide-transportation-infrastructure>; Paul W. Parfomak, Cong. Res. Serv., *Carbon Dioxide (CO₂) Pipeline Development: Federal Initiatives* (June 2, 2023), <https://crsreports.congress.gov/product/pdf/IN/IN12169>.

¹⁶⁶ See Press Release, DOE, *OCED Selects Three Projects in CA, ND, and TX to Reduce Harmful Carbon Pollution, Create New Economic Opportunities, and Advance Carbon Reducing Technologies*, <https://www.energy.gov/oced/articles/oced-selects-three-projects-ca-nd-and-tx-reduce-harmful-carbon-pollution-create-new>.

¹⁶⁷ See Cong. Budget Off., *Carbon Capture and Storage in the United States*, at 16, tbl. 2-2 (Dec. 2023), <https://www.cbo.gov/system/files/2023-12/59345-carbon-capture-storage.pdf>.