Comments of the Power Generators Air Coalition on EPA's Proposed Repeal of Greenhouse Gas Emissions Standards for Fossil-Fuel Fired Electric Generating Units

90 Fed. Reg. 25,752 (June 17, 2025)
Docket ID No. EPA-HQ-OAR-2025-0124

The Power Generators Air Coalition ("PGen") respectfully submits these comments to the U.S. Environmental Protection Agency ("EPA" or "the Agency") in response to EPA's proposed rule entitled "Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units," which was published in the Federal Register on June 17, 2025 ("Proposed Repeal Rule").[1] The Proposed Repeal Rule involves the new source performance standards ("NSPS") for greenhouse gas ("GHG") emissions from new, modified, and reconstructed fossil fuel-fired electric generating units ("EGUs"), which were promulgated by EPA under section 111(b) of the Clean Air Act ("CAA" or "Act") in 2015[2] and 2024.[3] The Proposed Repeal Rule also involves the emission guidelines for GHG emissions from existing fossil fuel-fired steam generating units, including coal-, gas-, and oil-fired steam generating units, which were promulgated by EPA under section 111(d) of the CAA in 2024.[4]

EPA's 2024 rule, which promulgated Subpart TTTTa and Subpart UUUUb, is "EPA's most recent effort to regulate GHG emissions from the power sector, [and is] commonly referred to as the

---

[1] 90 Fed. Reg. 25,752 (June 17, 2025). PGen member the National Rural Electric Cooperative Association does not join in these comments.

[2] 40 C.F.R. part 60, Subpart TTTT ("Subpart TTTT"); *see also* Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510 (Oct. 23, 2015).

[3] 40 C.F.R. part 60, Subpart TTTTa ("Subpart TTTTa"); *see also* 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 Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024).

[4] 40 C.F.R. part 60, Subpart UUUUb ("Subpart UUUUb"); *see also* 89 Fed. Reg. at 39,798.

Carbon Pollution Standards."[5] The Carbon Pollution Standards were challenged in the U.S. Court of Appeals for the District of Columbia Circuit by 27 states, labor unions, and numerous industry parties.[6] Briefing and oral argument are complete in the case, which is currently being held in abeyance while EPA undergoes this rulemaking and considers whether to repeal or revise the Carbon Pollution Standards.[7] Petitioners' briefs in the litigation set forth the numerous reasons why the CPS Rule is unlawful and violates the CAA, and PGen attaches these briefs and incorporates them by reference herein.[8]

The Proposed Repeal Rule contains two options that EPA is considering. The first option, which EPA calls the "Primary Proposal," would, if finalized, repeal Subpart TTTT, Subpart TTTTa, and Subpart UUUUb in their entirety based on a determination by EPA that GHG emissions from fossil fuel-fired EGUs do not significantly contribute to air pollution that endangers public health and welfare.[9] The second option, which EPA calls the "Alternative Proposal," would, if finalized, revise EPA's 2024 determinations regarding the best system of emission reduction ("BSER") for certain subcategories within the fossil fuel-fired EGU source category, resulting in revisions to Subpart TTTTa and a repeal of Subpart UUUUb.[10]

[5] 90 Fed. Reg. at 25,754. The Carbon Pollution Standards are also referred to as the "CPS Rule" in these comments.

[6] *West Virginia v. EPA*, No. 24-1120 (and consolidated cases) (D.C. Cir.).

[7] Order, *West Virginia v. EPA*, No. 24-1120 (and consolidated cases), ECF No. 2113035 (D.C. Cir. Apr. 25, 2025).

[8] Opening Brief of Petitioners, *West Virginia v. EPA*, No. 24-1120 (and consolidated cases), ECF No. 2073644 (D.C. Cir. Sept. 6, 2024); Reply Brief of Petitioners, *West Virginia v. EPA*, No. 24-1120 (and consolidated cases), ECF No. 2082029 (D.C. Cir. Oct. 25, 2025). Both of these briefs are included in Addendum 1 to these comments and are incorporated herein.

[9] *See* 90 Fed. Reg. at 25,762-68.

[10] *See id.* at 25,768-77.

Background on PGen

PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies—investor-owned utilities, public power, and rural electric cooperatives—with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. PGen's individual members are collectively responsible for approximately 220,000 megawatts ("MW") of generation, and these individual members operate and serve over 47 million customers in 38 states. Given the diverse nature of PGen's members, these comments do not necessarily represent the viewpoint of every individual PGen member.

PGen is a collaborative effort of electric generators to share information and expertise in the interest of effectively managing air emissions to meet and exceed environmental laws and regulations and in the interest of informing sound regulation and public policy.[11] PGen's members include leaders in the fundamental transition to cleaner energy that is currently occurring in the industry. PGen as an organization does not participate in legislative lobbying or litigation. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation.

PGen members own and operate fossil fuel-fired EGUs that are the subject of the Proposed Repeal Rule, as well as renewable resources, like wind and solar, and carbon-free nuclear power plants. As such, PGen is uniquely qualified to provide comments to EPA because its members have owned and operated fossil fuel-fired EGUs for decades and are subject to various provisions of the CAA, including section 111, the provision at issue in the Proposed Repeal Rule.

---

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

PGen's Position on the Carbon Pollution Standards and the Proposed Repeal Rule

At the outset, PGen wants to make clear that it understands the importance of reducing GHG emissions to address climate change. As EPA has noted, the electricity generating sector has made significant GHG reductions, with carbon dioxide ("CO_2") emissions[12] "declin[ing] by 36 percent since 2005."[13] As noted in the Proposed Repeal Rule, "[t]he share of GHG emissions from the U.S. power sector, including CO_2, to global concentrations of GHGs in the atmosphere is relatively minor and has been declining over time," with U.S. power sector GHG emissions falling from 5.5 percent of global GHG emissions in 2005 to 3.0 percent in 2022.[14] Indeed, the power sector is the industry with by far the greatest amount of reductions from 2000 to 2022,[15] and the sector is no longer the biggest contributor to U.S. GHG emissions, having been surpassed by the transportation sector.[16] The vast majority of PGen members have established goals to reduce their GHG emissions, and several PGen members have set net-zero goals.

While PGen members take seriously the need to reduce GHG emissions, they take equally seriously their obligation to provide reliable electricity at an affordable price. PGen members have consistently expressed concern that the Carbon Pollution Standards as finalized by EPA in 2024 will interfere with this critical obligation, which could undermine public support for electric sector efforts to reduce emissions through low- and zero-carbon sources like wind, solar, and nuclear.

---

[12] CO_2 is the GHG that is regulated from fossil fuel-fired EGUs under Subparts TTTT, TTTTa, and UUUUb.

[13] 89 Fed. Reg. at 39,812.

[14] 90 Fed. Reg. at 25,767-68.

[15] Center for Climate and Energy Solutions, U.S. Emissions, https://www.c2es.org/content/u-s-emissions/ (last visited Aug. 5, 2025) (graphic showing Energy-Related Carbon Dioxide Emissions by Sector (MMtCO2) 2000-2022) (citing Monthly Energy Review (U.S. Energy Information Administration ("EIA"), 2023)).

[16] *Id.*

PGen has been actively engaged with EPA on this important issue since the information-seeking stage, when PGen provided written comments to EPA's pre-proposal non-rulemaking docket.[17] PGen also submitted extensive written comments on the proposed Carbon Pollution Standards.[18]

As specified in these comments, PGen supports the Proposed Repeal Rule, which will bring much needed relief to the power industry to enable it to meet the surging demand for electricity that has been occurring and is forecasted to continue due to increased energy needs related to data storage, artificial intelligence ("AI"), and other large customer growth. The Alternative Proposal, if accompanied by some adjustments to the NSPS for new combustion turbines (also referred to as "CTs"), would remedy the legal defects of the CPS Rule and provide much needed regulatory relief to the power industry while providing greater certainty. PGen believes this option provides an immediate pathway for the relief the industry needs from the current requirements of the Carbon Pollution Standards.

PGen's detailed comments on the Proposed Repeal Rule follow. PGen remains available to continue to work with EPA in any way that the Agency may find helpful as it considers issues related to the regulation of GHG emissions from the power sector under section 111 of the CAA.

---

[17] Comments of the Power Generators Air Coalition to EPA's Pre-Proposal Non-Rulemaking Docket on Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units, Docket ID No. EPA-HQ-OAR-2022-0723-0031 (Dec. 22, 2022) ("PGen Pre-Proposal Comments"). The PGen Pre-Proposal Comments are included in Addendum 2 to these comments and incorporated herein.

[18] Comments of the Power Generators Air Coalition on the U.S. Environmental Protection Agency's New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, Docket ID No. EPA-HQ-OAR-2023-0072-0710 (Aug. 8, 2023) ("PGen Comments on the Proposed Carbon Pollution Standards"). The PGen Comments on the Proposed Carbon Pollution Standards are included in Addendum 2 to these comments and incorporated herein.

Executive Summary

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

Demand for electricity is increasing rapidly, with this increased demand forecast to continue for the foreseeable future. The Carbon Pollution Standards are providing obstacles to the ability of the power industry to meet electricity demand, and electric generators need immediate relief from these standards to ensure that they will be able to continue providing reliable and affordable electricity to their customers. PGen expressed its concerns regarding resource capacity and reliability to EPA during the rulemaking on the Carbon Pollution Standards and was not alone in doing so. States and grid operators also told EPA about this issue, but the Agency finalized the CPS Rule anyway.

Since the Carbon Pollution Standards were finalized, the problem has grown worse. The North American Electric Reliability Corporation (NERC)'s recent Long-Term Reliability Assessment predicts massive increases in electricity demand over the next ten years and contains warnings regarding "critical reliability challenges." The Carbon Pollution Standards will compound these resource capacity and reliability issues if they are left in place because they will cause the early retirement of coal-fired generation and because they impose capacity factor limitations on new, larger combined cycle combustion turbines, thus limiting the ability of new generation to replace retired generation and meet increased demand. Indeed, the Carbon Pollution Standards are already having an adverse effect on the ability of electric generators to construct new base load generation.

PGen urges EPA to finalize the Alternative Proposal, which if coupled with the revisions needed to the NSPS for new base load combustion turbines in Phase 1 and for intermediate combustion turbines that PGen discusses in detail in Section III of these comments, would remedy the legal defects of the Carbon Pollution Standards and provide needed relief to the power industry.

The portions of the Carbon Pollution Standards that rely on a BSER of 90 percent carbon capture and storage ("CCS")[19] do not comply with the requirements of Section 111 of the CAA, and EPA properly proposes to repeal them for the following reasons:

- CCS is not adequately demonstrated at stationary combustion turbines. The two projects EPA cited in the CPS Rule to support its determination that CCS was adequately demonstrated actually support the opposite conclusion. The Bellingham Energy Center was a slipstream facility that is not comparable to EGUs, and the Peterhead Power Station in Scotland is not yet operational. Other projects cited by EPA are not operational (or not even constructed).

- CCS is not adequately demonstrated for steam generating units. EPA's determination that it was relied primarily on the Boundary Dam Unit 3 project, which has never demonstrated 90 percent capture of CO_2 and which is a relatively small power plant of only 110 megawatts (MW). Other projects cited by EPA are small, capture CO_2 from a slipstream, do not capture CO_2 at a 90 percent level, and/or received federal funding that disqualifies the projects from consideration as a BSER. EPA also cited unconstructed projects and vendor statements, neither of which can support a BSER determination.

- The NSPS and presumptive standards of performance that are based on a 90 percent CCS BSER are not achievable. No commercial EGU has ever achieved 90 percent CCS on a sustained basis, as the Carbon Pollution Standards require, and EPA did not cite a single example of a facility meeting this standard in the final CPS Rule. Other reasons also support EPA's determination that CCS is not achievable, including that the infrastructure needed for CCS, including pipelines and carbon storage facilities, does not exist, and it cannot be constructed by the compliance deadlines in the CPR Rule. Many areas of the country also do not have convenient access to geologic storage for CCS.

- CCS is not cost-effective. In past rulemakings, EPA previously has consistently rejected CCS as too costly. To get around that problem in the Carbon Pollution Standards, EPA inappropriately relied on tax credits. But tax credits do not reduce the costs of CCS; they transfer them from power plant owners to taxpayers. And even if tax credits could be taken into account, there are significant limitations on the ability of an owner to obtain them, and nothing would prevent Congress from taking them away.

- Many other obstacles exist that prevent CCS from being considered as a "best" system to reduce GHG emissions from EGUs, including: (1) geographic and site limitations; (2) water constraints; and (3) parasitic load.

[19] CCS is sometimes also referred to as carbon capture, utilization, and storage (CCUS).

The portion of the Carbon Pollution Standards that identifies co-firing with 40 percent natural gas as the BSER for existing medium-term coal-fired steam generating units does not comply with section 111 of the CAA, and EPA properly proposes to repeal it. Requiring a coal-fired EGU to become a "hybrid" plant that burns 40 percent natural gas constitutes impermissible generation shifting and is beyond EPA's authority. And even if fuel switching were permissible, which it is not, the presumptive emission limit based on 40 percent co-firing is not achievable because the majority of coal plants do not have access to natural gas, and the vast majority of those plants that do have access to gas use it only at very low levels for boiler startup or to hold the unit in "warm standby." EGU owners will not be able to construct the needed infrastructure by the compliance deadline in the CPR Rule. Finally, co-firing with 40 percent natural gas is also not cost-effective because of the need to construct expensive pipeline infrastructure.

EPA properly proposes to repeal the requirements for existing natural gas- and oil-fired steam generating units because these requirements would result in only de minimis—if any—emission reductions, while imposing significant requirements on states to develop state plans. These standards are not necessary, in any event, because they are based on what those sources are already doing (i.e., business as usual).

The major questions doctrine also supports EPA's Alternative Proposal. The Carbon Pollution Standards did not remedy the legal deficiencies identified by the Supreme Court in *West Virginia v. EPA*. Although those standards do not require overt generation shifting (with the exception of the 40 percent gas co-firing requirement), they lead to the same result because they are based on technology that is not adequately demonstrated, require compliance with emission rates that are not achievable, and are not cost-effective.

Critically, if EPA decides to adopt the Alternative Proposal (which PGen urges EPA to do), EPA needs to reconsider the CO_2 emission standards for new base load combustion turbines in Phase

1 and the standards for intermediate load combustion turbines, and PGen requests that EPA do so as quickly as possible in a supplemental rulemaking. As part of EPA's reconsideration of these standards, the Agency should establish a single, input-based CO_2 emission standard for all combustion turbines as a matter of policy because as detailed in these comments the capacity-factor basis for the Carbon Pollution Standards for combustion turbines have significant energy and cost implications.

If EPA does retain some form of the NSPS as pounds of CO_2 per megawatt hour ("lb CO_2/MWh"), then the NSPS for the intermediate load subcategory must be reconsidered because the existing intermediate load standards are unachievable by even highly efficient turbines, and because the standard is based on a single set of operating parameters, it effectively dictates the types of operations and particular uses of the turbine, which is impermissible under the CAA. Moreover, even if operational constraints can be the basis of the BSER, EPA should have established a significantly higher standard for this subcategory. Based on the data analyzed by PGen's expert, PGen recommends that the standards for non-low-load simple-cycle combustion turbines be revised to at least 1,350 lb CO_2/MWh for units larger than 200 MW (roughly, about 2,000 MMBtu/h base load rating), and no less than 1,500 lb CO_2/MWh for smaller simple-cycle combustion turbines (less than 2,000 MMBtu/h base load rating).

If EPA retains some form of the NSPS as lb CO_2/MWh, then the NSPS for the Phase 1 base load subcategory must also be reconsidered. The current Phase 1 NSPS for the base load subcategory is deeply flawed because it is unachievable by a number of highly efficient turbines on the market. EPA based the standard on only one unit that is not representative of the variety of highly efficient combustion turbines that are available on the market. Further, even if operational constraints can be the basis of the BSER, EPA should have established a significantly higher standard for this subcategory. Based on the data analyzed by PGen's expert, PGen recommends the standards for non-low-load combined-cycle combustion turbines be revised to be at least 900 lb CO_2/MWh for units larger than 400 MW (roughly, about 2,500 MMBtu/h base load rating), and no less than 1,000 lb CO_2/MWh for smaller combined-cycle combustion turbines (less than 2,500 MMBtu/h base load rating).

PGen urges EPA to change its method of subcategorization that is currently based on problematic capacity factor designations and instead subcategorize the units by the configuration of the turbine (i.e., simple-cycle or combined-cycle). But if EPA nevertheless retains the capacity factor basis to differentiate between intermediate and base load turbines, then the dividing threshold between simple-cycle combustion turbines and combined-cycle combustion turbines should be revised upwards to an annual capacity factor of 60 percent.

Although PGen believes the Alternative Proposal offers a more certain and durable option, PGen also offers comments on the Primary Proposal for EPA's consideration in the event EPA decides to finalize it, perhaps after it finalizes the Alternative Proposal. First, the CAA requires that before EPA can list a new source category under section 111, the Agency must find that the category significantly contributes to endangering air pollution. EPA did not do this when it listed the fossil fuel-fired EGU source category in 2015, and EPA unlawfully relied on listings of two other pre-existing source categories to justify the listing.

Second, before EPA may regulate a pollutant from a listed source category, the CAA requires EPA to find that emissions of that pollutant from the listed source category significantly contribute to endangering air pollution. Otherwise, the Agency would have unfettered discretion to regulation anything from a source as long as it had made a finding for a single pollutant. EPA's attempt to limit its discretion through a "rational basis" test is unavailing and has no basis in the CAA.

Finally, the history of EPA's attempts to regulate GHG emissions from fossil fuel-fired EGUs under section 111 over the past decade demonstrate it may not be possible to regulate GHGs from EGUs under the NSPS program. The Supreme Court made clear in *Utility Air Regulatory Group v.*

EPA[20] that GHGs should be regulated only when it makes sense within that program's overall regulatory scheme. The 10-year history of attempts to regulate GHG emissions from fossil fuel-fired EGUs under section 111 shows including GHGs in the NSPS program for these sources may not fit well or easily within the statutory scheme.

Detailed Comments

I. The Demand for Electricity is Increasing Rapidly, and Immediate Relief from the Unlawful CPS is Needed to Ensure that the Industry Can Continue to Provide Reliable and Affordable Electricity to the Nation.

During rulemaking on the Carbon Pollution Standards, PGen told EPA that the CPS Rule would threaten both the reliability and affordability of electricity.[21] PGen was not alone. States, grid operators, and other power sector organizations all submitted comments sounding the alarm about the grid reliability issues that would occur if EPA finalized the Carbon Pollution Standards. States warned "that grid reliability is especially fragile" due to increasing demands from population growth, increasing reliance by society on electricity, and new high-load users of electricity such as data centers and cryptocurrency mining.[22] Several grid operators warned EPA that the CPS Rule "would greatly exacerbate an ongoing loss of critical, dispatchable generating capacity that is needed to ensure reliability."[23] The American Public Power Association ("APPA") told EPA that the CPS Rule "will place further strain on electric reliability, give rise to more health and safety concerns, increase the

[20] 573 U.S. at 302, 324 (2014) ("*UARG v. EPA*").

[21] PGen Comments on Proposed Carbon Pollution Standards at 9-18.

[22] Comments submitted by the Attorneys General of State of West Virginia, et al. at 46, EPA-HQ-OAR-2023-0072-0798 (Aug. 8, 2023).

[23] Joint Comments submitted by Electric Reliability Council of Texas, Inc., Midcontinent Independent System Operator, Inc. ("MISO"), PJM Interconnection, L.L.C., and Southwest Power Pool, Inc. ("SPP") at 5, EPA-HQ-OAR-2023-0072-0673 (Aug. 8, 2023); *see also* Comments submitted by SPP at 8, EPA-HQ-OAR-2023-0072-0670 (Aug. 8, 2023) (noting the CPS "will jeopardize, through accelerated retirement or reduced output, SPP's ability to utilize [fossil fuel facilities] until such time as adequate clean alternatives are available"); Comments submitted by MISO at 2, EPA-HQ-OAR-2023-0072-0623 (Aug. 8, 2023) (warning about "the risk of a looming [energy] shortfall").

cost of electricity, and potentially undermine public support for prudent programs aimed at reducing GHGs."[24]

Section 111(a)(1) of the CAA requires EPA to "tak[e] into account … energy requirements" when determining a BSER.[25] Yet, despite the warnings being sounded by commenters, the Agency proceeded to finalize the Carbon Pollution Standards anyway, claiming to have fixed any reliability problems with the inclusion of some new "compliance flexibilities" and "reliability mechanisms."[26] But these flexibilities and adjustments are only temporary at best, and there is no guarantee that a source can utilize them.[27] For example, while the CPS Rule contains a short-term reliability mechanism that would allow an EGU to operate at baseline emission rates during a documented reliability emergency, this mechanism is of no use to a unit that was forced to retire because it could not meet the unachievable emission standards of the CPS Rule.

Further exacerbating the resource adequacy problem, since the Carbon Pollution Standards were proposed and finalized, electricity demand has continued to grow substantially, driven in large part by AI and its increased need for computing power and data storage. Forecasts show that demand will continue to grow significantly for the foreseeable future. The North American Electric Reliability Corporation ("NERC"), which is the electric reliability organization responsible for "assur[ing] the

---

[24] Comments submitted by APPA at 7, EPA-HQ-OAR-2023-0072-0566 (Aug. 8, 2023); *see also* Comments submitted by the National Rural Electric Cooperative Association at 24, EPA-HQ-OAR-2023-0072-0770 (Aug. 8, 2023) (alerting EPA that the "combination of premature retirements from coal units and (arbitrarily) low capacity factors from natural gas units will exacerbate the reliability issues"); Comments submitted by the Edison Electric Institute at 33, EPA-HQ-OAR-2023-0072-0772 (Aug. 8, 2023) (noting "capacity additions (the vast majority of which are intermittent resources with lesser accredited capacity) are not keeping pace with capacity retirements," which "presents significant near-term risks to system reliability, particularly during extreme events").

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

[26] 89 Fed. Reg. at 40,013-20.

[27] *See id.* (providing an extension of compliance deadline by only up to one year where an EGU's retirement is forecast to disrupt system reliability and where EPA approves the extension).

effective and efficient reduction of risks to the reliability and security of the grid" in most of North America, including all of the continental United States,[28] issued its most recent annual Long-Term Reliability Assessment ("LTRA") in December 2024 (and updated it on July 15, 2025). The 2024 LTRA notes the following regarding the explosive growth in electric demand since the Carbon Pollution Standards were proposed and finalized:

> **Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades**. Increasing amounts of large commercial and industrial loads are connecting rapidly to the [North American bulk power system ("BPS")]. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. **The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:**
>
> - The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 [gigawatts ("GW")] this LTRA up from over 80 GW in the 2023 LTRA.
>
> - The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW in this LTRA up from almost 92 GW in the 2023 LTRA.[29]

NERC also states that the electric grid "faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal [fossil fuel-fired] generators announce plans for retirement."[30] At the same time, NERC notes that the construction of new electric generating

[28] About NERC, https://www.nerc.com/AboutNERC/Pages/default.aspx.

[29] NERC, 2024 Long-Term Reliability Assessment at 8-9 (Dec. 2024, updated July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (emphases added).

[30] *Id.* at 6.

resources is "lagging."[31] Crucially, NERC says that "**[t]he trends point to critical reliability challenges facing the industry.**"[32]

If left in place as currently promulgated without any revision, the Carbon Pollution Standards will only exacerbate these reliability challenges because they will hasten the retirement of fossil fuel-fired EGUs in the United States while also impeding construction of new gas-fired combustion turbines (thus decreasing the availability of base load generation). The increased retirements of fossil fuel-fired EGUs in recent years has unequivocally decreased electric reliability. This can be seen in the exponential increase in requests to the U.S. Department of Energy ("DOE") under section 202(c) of the Federal Power Act to suspend compliance with environmental regulations in order to preserve the reliability of the bulk electric power system. From 2000 to 2019, DOE issued 8 orders under section 202(c).[33] That number of orders, which took place over a 20-year period of time, was nearly matched in 2022 alone, when 7 such emergency orders were issued.[34] Eighteen emergency orders have been issued by DOE since 2020, with 7 of those orders being issued after the Carbon Pollution Standards were proposed.[35]

The Carbon Pollution Standards compound the problem of significant capital investments either forcing early retirement or significantly curtailing the amount an EGU may run. This will further strain electric reliability, raise health and safety issues resulting from electric service disruptions, and

---

[31] *Id.*

[32] *Id.* (emphasis in original).

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

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

[35] *Id.*

increase the cost of electricity. These effects conflict with the purpose of the CAA "to promote the public health and welfare and the productive capacity of [the nation's] population."[36] The Carbon Pollution Standards require significant capital investment into coal-fired EGUs unless they commit to "cease operation prior to January 1, 2032."[37] Any coal-fired EGU that intends to operate after January 1, 2032, but retire before January 1, 2039, (i.e., a unit subcategorized as a "medium-term" unit), will need to make a substantial capital investment in the unit unless the unit already has access to natural gas in sufficient quantities and the capability to co-fire natural gas at high levels and complete these investments by January 1, 2030.[38] For any unit that intends to operate after January 1, 2039 (i.e., a unit subcategorized as a "long-term" unit), it must make capital investments in carbon capture and storage ("CCS") and complete them by January 1, 2032.[39] All of these requirements will almost certainly hasten the retirement of additional coal-fired EGU capacity

The Carbon Pollution Standards also inappropriately impose capacity factor restrictions on large, combined cycle combustion turbines that are typically used to supply base load generation. Under the CPS Rule, new base load combustion turbines, which the CPS Rule defines as combustion turbines that operate at greater than 40 percent of their capacity factor, must first comply with a Phase 1 emission limit that most combustion turbines cannot achieve (as discussed in more detail in Section III of these comments) and then beginning in 2032 must comply with an emission limit based on 90 percent CCS that is not adequately demonstrated, not achievable, and not cost-effective (as discussed in more detail in Section II of these comments).[40] These NSPS, which were adopted last year, are

---

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

[37] 40 C.F.R. §§ 60.5740b(a)(9)(ii).

[38] *See id.* §§ 60.5740b(a)(1)(ii), (a)(3); 60.5775b(c)(2).

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

[40] *See* Table 1 to Subpart TTTTa of Part 60.

already having a deleterious effect on the ability of electric generators to construct new base load CTs, with owners and operators having to be careful to operate these units at less than half of their electric generation capability to avoid being subcategorized as a "base load" unit. New construction permits issued since the publication of the proposed Carbon Pollution Standards require permit applicants to take enforceable restrictions on the operation of the combustion turbine to avoid triggering unworkable NSPS emission limits. This is almost certainly part of the reason for NERC's finding that less dispatchable capacity is being added to the grid than what was previously projected to be constructed.[41]

In sum, the demand for electricity is the highest that it has been in 20 years and is forecasted to continue to skyrocket. The Carbon Pollution Standards, which are currently in effect, have created a fundamental roadblock to the power industry being able to construct new generation to meet this rising demand for electricity. This roadblock to meeting rising demand is exacerbated by the Carbon Pollution Standards for existing coal-fired EGUs, which if they are not repealed will result in an acceleration in the retirement of those EGUs. Under section 111(a)(1) of the CAA, EPA must consider energy requirements when it promulgates NSPS or emission guidelines. The Carbon Pollution Standards did not adequately examine the issue of resource adequacy and reliability. The Proposed Repeal Rule remedies that infirmity and appropriately determines that repeal and/or revision of the Carbon Pollution Standards is necessary to ensure the reliability of electricity in the United States.

II. EPA's Alternative Proposal

The Proposed Repeal Rule includes an Alternative Proposal that provides a pathway that will remedy the most serious legal defects of the Carbon Pollution Standards and provide needed relief to

[41] *See* NERC, 2024 Long-Term Reliability Assessment, *supra* note 29, at 6.

the power industry. The Alternative Proposal would revise Subpart TTTTa to remove the unlawful CCS requirements for new base load combustion turbines in Phase 2 and for coal-fired steam generating units that undergo a large modification.[42] The Proposed Repeal Rule would also repeal Subpart UUUUb, the emission guidelines for existing fossil fuel-fired steam generating units.[43]

Because the Alternative Proposal would provide relief from the Carbon Pollution Standards by largely restoring the section 111(b) NSPS that apply to GHG emissions from new, modified, and reconstructed fossil fuel-fired EGUs to be within the authority Congress provided to EPA under the CAA, PGen urges EPA to immediately finalize this portion of the Proposed Repeal Rule so that the relief the industry needs can be provided quickly in a manner that may be more durable. This is particularly important given that the Carbon Pollution Standards are currently in effect and are presenting obstacles and restrictions on the ability of electric generators to construct new combustion turbines at a time when new generation is urgently needed to meet increased load demand as detailed in Section I. For these reasons, PGen urges EPA to finalize the Alternative Proposal quickly.

As discussed in detail in Section III, some targeted revisions to the NSPS for intermediate and base load combustion turbines are needed to ensure those NSPS are achievable, and PGen respectfully requests EPA issue a supplemental proposed rule as soon as possible to propose the needed revisions so that all of the revisions to the NSPS can be finalized together.[44]

---

[42] 90 Fed. Reg. at 25,768.

[43] *Id.*

[44] If it preferred, EPA could also issue a separate, standalone proposal to revise the intermediate load and Phase 1 base load performance standards for combustion turbines. If EPA decides to proceed in this fashion, the finalization of the Proposed Repeal Rule would provide relief from the most serious of the Carbon Pollution Standards' unlawful provisions, and PGen would simply request that EPA act quickly under this approach to finalize the revisions to the NSPS that would bring the remainder of the relief needed to the industry.

The Alternative Proposal rests on several proposed determinations:

- EPA proposes to find "that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units because it has not been adequately demonstrated and because the costs are not reasonable."[45]

- EPA further proposes to determine that the degree of emission limitation set forth in the emission guidelines for long-term coal-fired steam generating units is not achievable "because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date."[46]

- EPA proposes to repeal "the CCS-based requirements for coal-fired steam generating units undertaking a large modification" based on its determination "that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units."[47]

- EPA also proposes to determine that 90 percent CCS is not the BSER for new base load combustion turbine EGUs because (i) it has not been adequately demonstrated; (ii) it is not cost-effective; and (iii) it not achievable by the January 1, 2032 compliance date because the necessary infrastructure is unlikely to be ready by that time.[48]

- EPA proposes to conclude that 40 percent natural gas co-firing for existing medium-term coal fired steam generating units is not the BSER because this is not an efficient use of natural gas.[49]

- Finally, EPA proposes to repeal the requirements for existing natural gas- and oil-fired steam generating units "because it would be an inefficient use of State resources to develop, submit, and implement State plans solely for" these units because there are very few of these units and any emission reductions gained from the emission guidelines would be minimal.[50]

PGen agrees with and supports all of these conclusions for the reasons provided by EPA in the Proposed Repeal Rule, as well as the additional reasons set forth below.

[45] 90 Fed. Reg. at 25,768.

[46] *Id.*

[47] *Id.*

[48] *Id.* at 25,768-69.

[49] *Id.* at 25,768.

[50] *Id.*

A. Overview of the Legal Requirements Governing a Standard of Performance under Section 111 of the CAA

Regulation of new sources in a source category under section 111(b) of the CAA is a prerequisite to regulation of existing sources under section 111(d). Section 111 of the CAA directs EPA to list categories of stationary sources that it determines contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.[51] After a source category has been listed by EPA, the Agency is required to establish NSPS for new and modified sources for the category pursuant to CAA section 111(b).[52] Once EPA has issued an NSPS pursuant to 111(b), in certain limited situations that exist with regard to GHG emissions from EGUs, EPA is then authorized to issue emission guidelines under section 111(d) that will guide states in setting standards of performance for existing sources in the category.[53] EPA issued standards of performance for GHG emissions from new, modified, and reconstructed EGUs under section 111(b) for the first time in 2015, when it promulgated Subpart TTTT for the newly listed fossil fuel-fired EGU source category.[54] The Subpart TTTT regulations cover both steam generating units and combustion turbines.[55] In the Carbon Pollution Standards, EPA issued revised NSPS for steam generating units and for combustion turbines that were promulgated as Subpart TTTTa.[56] EPA also issued section 111(d) emission guidelines to address GHG emissions from existing steam generating units.[57]

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

[51] CAA § 111(b)(1)(A), 42 U.S.C. § 7411(b)(1)(A). The specific requirements of these determinations by EPA under section 111 are discussed in more detail in Sections IV.A and IV.B of these comments.

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

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

[54] 80 Fed. Reg. at 64,510.

[55] *Id.* Numerous parties filed petitions for review in the D.C. Circuit challenging the NSPS for steam generating units, which found partial CCS to be the BSER for new steam generating units as being unlawful, while no one challenged the NSPS for combustion turbines. *See North Dakota v. EPA*, No.

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[58]

Under the plain language of the CAA, therefore, an NSPS must be "achievable" by the regulated new sources within the designated source category using the BSER that has been "adequately demonstrated" for the new sources to which the standard applies, considering cost and other factors. An NSPS must require an emission limitation on a continuous basis through establishment of a numerical emissions limit and a compliance protocol to measure those emissions. Only in circumstances where it is not feasible to establish an enforceable numerical standard may EPA promulgate a design or work practice standard.[59]

In developing an NSPS for a type of new source, EPA must engage in a three-step analysis.[60] First, EPA identifies a system or systems of emission reduction that have been "adequately demonstrated" for that type of source. Second, EPA determines what emission levels are "achievable" by such sources using the adequately demonstrated system or systems.[61] Third, after this determination, EPA "must exercise its discretion to choose an achievable emission level which

15-1381 (and consolidated cases) (D.C. Cir.). This litigation has been stayed pending EPA's administrative review of the 2015 NSPS.

[56] 89 Fed. Reg. at 39,799, 39,806.

[57] *Id.* at 39,799. EPA did not finalize proposed emission guidelines for existing combustion turbines in the final CPS Rule. *Id.*

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

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

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

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

represents the best balance of economic, environmental, and energy considerations."[62] Although an NSPS must be based on the performance of BSER incorporated into the design of the type of source to which the standard applies, it may not require individual new sources to install or operate the particular technology or system identified as BSER to meet the numerical performance level established by the NSPS.[63]

1. "Adequately Demonstrated"

Any control technology selected as BSER must first be a technology that has been "adequately demonstrated."[64] The D.C. Circuit has held that a system that has been adequately demonstrated is "one which has been **shown** to be reasonably **reliable**, reasonably **efficient**, and which can reasonably be expected to serve the interests of pollution control **without becoming exorbitantly costly** in an economic or environmental way."[65] Thus, an adequately demonstrated system must have an operational history that shows more than mere technical feasibility: it must be dependable and effective, available at a reasonable cost for individual sources, and based on actual operating experience within the source category or at sufficiently similar sources.

Although EPA has some discretion to extrapolate from other industries in determining whether a technology demonstrated in one industry is adequately demonstrated for another industry, that discretion is significantly limited. EPA may look to a technology's performance in another industry only if experience in that context is sufficiently representative of operations of sources in the

---

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

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

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

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

category to be regulated.[66] Any EPA extrapolations from one category to another are "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry" or "mere speculation or conjecture."[67] This latitude is further narrowed by the fact that NSPS are effective upon proposal and provide no "'lead time'" for further technological development.[68]

To be adequately demonstrated for all sources within a category or subcategory, a technology must be available for each source type to which the standard will apply. For example, in its 2005 proposed revisions to the NSPS for Subpart Da units, EPA rejected supercritical boiler design, integrated gasification combined cycle technology, and the use of clean fuels as potential bases for its revised standards due in part to the unavailability of these options across source types to which the standards would apply.[69] In assessing adequate demonstration, courts often consider issues such as whether: (i) sufficient implementation experience has accrued at full-scale facilities; (ii) data from prototype facilities or other industries are sufficiently representative to warrant extrapolation to the source category; (iii) experience has accrued with all fuel types; and (iv) unresolved issues remain regarding waste disposal or other harmful environmental effects.[70]

2. "Achievable"

Once EPA identifies an "adequately demonstrated" system, it then must determine what levels of emissions are "achievable" by individual sources applying that system. EPA must explain how the

---

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

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

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

[69] 70 Fed. Reg. 9706, 9712, 9714, 9715 (Feb. 28, 2005).

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

standard "is achievable under the range of relevant conditions which may affect the emissions to be regulated," including "under most adverse conditions which can reasonably be expected to recur."[71] A standard that applies to all new sources in a category must be achievable "for the industry as a whole" and not just for a subset of sources.[72] As with determining whether a technology is adequately demonstrated, EPA may not base its determination that a standard is achievable on "mere speculation or conjecture."[73]

In order to show that a given emission level is "achievable" by a system of emission reduction, EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard."[74] In other words, the validity of EPA's achievability determination depends on how fully it has accounted for the variations among sources in the regulated category that could affect emission levels. Courts have repeatedly rejected NSPS that EPA deemed "achievable" based on test data from a narrow set of sample sources that did not represent the full range of relevant variability among sources to which the standard will apply.[75] In these cases, courts have required EPA to consider such variables as source type, feedstock or fuel type, the relationship between emissions generated and the effectiveness of control technology, and regional variations.[76] An NSPS "establishes what every source can achieve,

---

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

[72] *Id.* at 431.

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

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

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

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

not the best that a source could do."[77] It is intended to represent the "least common denominator" of control standards that can "be reasonably achieved by [a] new source **anywhere** in the nation."[78]

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

After EPA has identified the emission levels achievable through the use of adequately demonstrated technology, the Agency selects a standard from the range of demonstrated technologies that "represents the best balance of economic, environmental, and energy considerations."[79] At this stage, in addition to the statutory factors of "the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements,"[80] EPA may consider a proposed standard's projected emission reductions and its potential to encourage (rather than mandate) technological innovation.[81]

Moreover, in determining BSER, EPA must ensure that standards do "not give a competitive advantage to one State over another in attracting industry."[82] For example, in *Sierra Club*, the D.C. Circuit observed that "an efficient water intensive technology … might be 'best' in the East where water is plentiful, but environmentally disastrous in the water-scarce West."[83] Thus, the water intensive technology could not be selected as the BSER because it would have had the effect of precluding

---

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

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

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

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

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

[82] *Id.* at 325.

[83] *Id.* at 330.

construction of new sources in states that lack the resources necessary (in this case, water) to allow compliance with the standard at a reasonable cost.

EPA must account for these factors at the plant level and may consider them "at the national and regional levels and over time."[84] The Agency's discretion, however, to consider costs and environmental or energy impacts at the national level does not permit it to disregard these impacts in selecting among the technologies that are demonstrated for individual sources. The D.C. Circuit made clear in *Sierra Club* that the CAA authorizes EPA to examine the national scale in addition to—not instead of—assessing a standard's impact on individual sources.[85] Thus, EPA may not set an NSPS based on national-scale considerations that would impose unreasonable costs, environmental impacts, or energy requirements at the level of individual plants.

EPA may not rely on consideration of costs and environmental or energy impacts on a national level to justify a standard of performance that is more stringent than would be permitted based on source-level factors used to select among the demonstrated technologies. The CAA allows EPA to account for these impacts as a safety valve to prevent regulators from adopting standards of performance that cause more economic or environmental harm than they prevent, and not as a method for the Agency to demand additional emission reductions.[86] The Agency may consider these factors only after ruling out emission levels that are not achievable based on adequately demonstrated technology. Accordingly, EPA cannot rely on purported national or regional benefits to justify standards of performance that are unachievable, based on inadequately demonstrated technology, or otherwise unreasonable at the individual source level.

---

[84] *Id.*

[85] *Id.*

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

B. The Portions of the CPS Rule that Rely on 90 Percent CCS as the BSER Do Not Comply with Section 111's Requirements, and EPA Properly Proposes to Repeal Them (C-16, C-33[87]).

While CCS is a developing technology, it has not yet met the legal threshold to be considered a BSER. CCS is currently making advancements through a variety of pilot projects throughout the United States. Some PGen members are actively investigating the feasibility of CCS at a portion of their facilities and hope to be able to rely on this technology in the future to reduce GHG emissions. While progress is being made, however, EPA is correct in the Proposed Repeal Rule to propose to conclude that the technology is not yet developed enough in the power sector to cross the regulatory threshold into being "adequately demonstrated," as required for any BSER under the CAA.[88] There is insufficient experience at this time with CCS in commercial operation to find that the technology is currently feasible or reliable for widespread application in the electric generation industry—particularly at commercial scale and especially for utility combustion turbines where the technology has yet to be applied. Further, even if the technology were ready for more widespread deployment (which it is not), several issues remain that technological development cannot resolve, including geographical constraints, access to water, deficient pipeline infrastructure, parasitic load, and cost that prevent the technology from being properly selected as a BSER.

In the Proposed Repeal Rule, EPA correctly proposes to repeal all of the CPS Rule's determinations that CCS is BSER.[89] The selection of CCS as a BSER for fossil fuel-fired EGUs violates section 111 of the CAA because it fails every prong of the three-step test for determining a BSER: (1) CCS is not adequately demonstrated at fossil fuel-fired EGUs; (2) any emission standard

---

[87] References to "C-__" in various headings throughout these comments refer to the numbers EPA gave to specific issues on which it is soliciting comment in the Proposed Repeal Rule. *See* 90 Fed. Reg. at 25,777-79.

[88] *Id.* at 25,769-72 (steam generating units), 25,775-76 (combustion turbines).

[89] *Id.* at 25,768-69.

based on 90 percent CCS at these EGUs is not achievable; (3) CCS is not cost-effective; and (4) even if CCS were adequately demonstrated, achievable, and cost-effective for these EGUs (which it is not), it has numerous other factors that prohibit its being considered "best." Each of these infirmities is discussed further below.

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

a. Combustion Turbines (C-34, C-35)

Any appropriate analysis of the projects cited by EPA in the CPS Rule to support its determination that 90 percent CCS is adequately demonstrated for base load combustion turbines during Phase 2 reveals that the evidence cannot support a BSER determination, as EPA now properly recognizes in the Proposed Repeal Rule. In the CPS Rule, EPA claimed two projects supported its BSER determination: the Bellingham Energy Center in Massachusetts,[90] and the Peterhead Power Station in Scotland.[91] Neither of these projects supports that determination. At the Bellingham Energy Center, CCS was applied to an existing combined cycle turbine. The 40-megawatt ("MW") slipstream capture facility operated from 1991 to 2005 and captured 85 to 95 percent of the CO_2 in the slipstream for use in the food industry.[92] A slipstream capture facility is not comparable to the amount of capture that is required at large fossil fuel-fired EGUs.[93] Moreover, "[o]perating CCUS or any environmental control process as a 'slipstream' of gas, in contrast to being inseparably linked to the host unit, provides flexibility to manage uncertainties."[94] Specifically, a slipstream "avoid[s] issues with load ramping up

---

[90] 89 Fed. Reg. at 39,926-27.

[91] *Id.* at 39,927.

[92] *See id.* at 39,926. Because this project involved utilization of the captured CO_2 onsite for use in the food industry, it did not involve any pipeline transport or storage component.

[93] J.E. Cichanowicz, M.C. Hein, Analysis of Carbon Capture Utilization and Sequestration Technology As BSER and New Source Performance Standards Under the 2024 Greenhouse Gas (GHG) for Fossil-Fired EGUs at 4 (Aug. 2025) (noting the gas turbine at Bellingham is only about 1/6th that of a J- or H-Class Frame turbine) (C&H 2025 CCS Technical Report) (Attachment 1 to these comments).

[94] *Id.*

or down, startup/shutdown, or process 'upsets.'"[95] Success at a slipstream is not comparable to the dynamic actions that occur at an EGU and is therefore not indicative of future success at an EGU.[96]

The second project EPA relies on—the Peterhead Power Station in Scotland—"is in the planning stages of development" and is not yet in operation.[97] A plant that is not yet operational cannot serve as the basis for an adequately demonstrated determination because the technology has not yet "been shown to be reasonably reliable, reasonably efficient, and … reasonably … expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[98] To be considered as an adequately demonstrated technology, there must be an operational history that shows more than mere technical feasibility and the determination must be based on actual operating experience within the source category or at sufficiently similar sources. EPA's citation to other projects in the CPS Rule that are likewise in the development stages and not yet operational[99] are similarly unavailing.

The Carbon Pollution Standards then shifted to examining projects that received assistance under the EPAct.[100] EPA properly recognized in the CPS Rule that EPAct "constrained how the EPA could rely on [EPAct] assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111,"[101] The specific language of EPAct that constrains EPA states

---

[95] *Id.*

[96] *Id.* at 6.

[97] 89 Fed. Reg. 39,927.

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

[99] 89 Fed. Reg. at 39,927 (noting "**plans**" to use CCS technology at a facility in Kern County, California, and noting that "**when installed**," the facility "**is expected**" to reduce the facility's CO_2 emissions) (emphases added); *id.* (discussing "several **planned** projects using NET Power's Allam-Fetvedt Cycle" and that cycle's "**[p]otential** advantages") (emphases added).

[100] *Id.* at 39,927-28.

[101] *Id.* at 39,878.

that "[n]o technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be [] adequately demonstrated for purposes of section 111 of the Clean Air Act."[102] Congress was clear. EPA may not base an adequately demonstrated determination on technologies that receive monies under EPAct. EPA's reliance in the CPS Rule on EPAct funded projects, even for the purpose of "support[ing] or corroborat[ing] other information that supports such a determination,"[103] is impermissible.

Despite this clear congressional prohibition, EPA listed at least fourteen EPAct funded projects at stationary combustion turbines[104] that it said "provide corroborating evidence that capture of at least 90 percent is accepted within the industry."[105] First, the standard under section 111 is "adequately demonstrated," not industry acceptance. Second, even if these projects could be considered—which they cannot—they cannot support an adequately demonstrated determination by EPA for one simple reason: **none** of them are actually constructed and in operation, as can be seen in the CPS Rule: (1) "CCS is **planned**" for the Sutter Energy Center in Yuba City, California; (2) the Deer Park Energy Center in Deer Park, Texas, "**will be designed** to capture 95 percent or more of the flue gas from the five combustion turbines at the" facility; (3) CCS "**is planned**" for the Baytown Energy Center in Baytown, Texas; (4) a new combustion turbine in West Virginia "**will utilize** CCS" and "**is planned to begin operation later this decade**"; (4) General Electric project in Bucks, Alabama, "is **targeting** commercial deployment **by 2030**"; (5) Wood Environmental & Infrastructure

[102] EPAct § 402(i), 42 U.S.C. § 15962(a). Similar EPAct language was codified in the Internal Revenue Code and restricts EPA from considering technology that received tax credits under the EPAct. *Id.* § 1307(b), 26 U.S.C. § 48A(g); *see also* 89 Fed. Reg. at 39,878-79 n.613.

[103] 89 Fed. Reg. at 39,855.

[104] In addition to the fourteen projects listed, EPA notes "[t]here are also several announced NET Power Allam-Fetvedt Cycle based CO_2 capture projects that are EPAct[]-assisted." *Id.* at 39,928.

[105] *Id.*

Solutions in Blue Bell, Pennsylvania, awarded funds "to complete an **engineering design study**" for a project whose "**aim** is to reduce CO_2 emissions by 95 percent"; (6) General Electric Research in Niskayuna, New York, awarded funds to "**develop** a design to capture 95 percent of CO_2 from combined cycle turbine flue gas"; (7) SRI International in Menlo Park, California, awarded funds "to **design, build, and test** a technology that can capture at least 95 percent of CO_2"; (8) CORMETECH, Inc. in Charlotte, North Carolina, awarded funds "to further **develop, optimize, and test** a new, lower-cost technology to capture CO_2 from combined cycle turbine flue gas and **improve scalability to large, combined cycle turbines**"; (9) TDA Research, Inc. in Wheat Ridge, Colorado, awarded funds "to **build and test** a post-combustion capture process to **improve the performance** of combined cycle turbine flue gas CO_2 capture"; (10) GE Gas Power in Schenectady, New York, awarded funds "to **perform an engineering design study** to incorporate a 95 percent CO_2 capture solution for an existing combined cycle turbine site while **providing lower costs and scalability to other sites**"; (11) Electric Power Research Institute in Palo Alto, California, awarded funds "to **complete a study** to retrofit a 700-MWe combined cycle turbine with a carbon capture system"; (12) Gas Technology Institute in Des Plaines, Illinois, awarded funds "to **develop membrane technology** capable of capturing more than 97 percent of combined cycle turbine CO_2 flue gas"; (13) RTI International in Research Triangle Park, North Carolina, awarded funds "to **test a novel** non-aqueous solvent **technology**"; and (14) Tampa Electric Company in Tampa, Florida, awarded money "to **conduct a study** retrofitting" one of its plants "with post-combustion CO_2 capture technology **aiming** to achieve a 95 percent capture rate."[106] None of these studies and tests can support a determination by EPA that CCS is currently adequately demonstrated as a system of emission reduction for stationary combustion turbines.

---

[106] *Id.* at 39,927-28 (emphases added).

EPA's determination in the Carbon Pollution Standards that CCS is adequately demonstrated for new and existing combustion turbines is not grounded in any actual experience with this technology at these types of EGUs. EPA's proposed determination is unlawful because it is "based on 'crystal ball' inquiry"[107] and "mere speculation or conjecture."[108] For these reasons, EPA is correctly "proposing to determine that CCS with 90 percent capture is not the phase 2 BSER for base load combustion turbine EGUs because it has not been adequately demonstrated."[109]

b. Steam Generating Units (C-17, C-18, C-19, C-20)

CCS is not adequately demonstrated for use at existing coal-fired steam generating units, and EPA's determination in the Carbon Pollution Standards to the contrary is unfounded, as discussed in detail below. As a result, EPA's determination in the CPS Rule that CCS with 90 percent capture of CO_2 is the BSER for long-term coal-fired steam generating units[110] and for large modifications at those units[111] violates section 111 of the CAA, and EPA appropriately proposes to repeal these BSER determinations in the Proposed Repeal Rule.[112]

EPA's findings in the CPS Rule that 90 percent CCS is BSER for long-term steam generating units and steam generating units undergoing a large modification was primarily based on a single project at a coal-fired steam generating unit (SaskPower's Boundary Dam Unit 3 project in Saskatchewan, Canada).[113] In the CPS Rule, EPA also cited some slipstream power plant projects

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

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

[109] 90 Fed. Reg. at 25,775.

[110] 89 Fed. Reg. at 39,801.

[111] *Id.* at 39,954.

[112] 90 Fed. Reg. at 25,773, 25,775.

[113] *Id.* at 25,769.

(Plant Barry,[114] Petra Nova,[115] AES's Warrior Run and Shady Point plants,[116] and the Argus Cogeneration Plan[117]), most of which received EPAct05 funding, as additional support. None of these projects provides the requisite level of support for an adequate demonstration showing, and EPA is correct to propose to withdraw its previous BSER determinations now.

The only CCS project operating in North America that is relevant to utility power generation is the SaskPower Boundary Dam Unit 3 project in Saskatchewan, Canada. But Boundary Dam does not support EPA's previous adequately demonstrated determination project as it has had technical difficulties and has never demonstrated 90 percent capture of CO_2. As EPA states in the Proposed Repeal Rule, "[w]hile Boundary Dam Unit 3 achieved 89.7 percent capture over a 3-day test early in its operation, longer-term capture levels have been lower," with the unit "achiev[ing] a total capture efficiency of not more than 63 percent in a calendar year" between 2015 and 2022.[118] In fact, during the rulemaking on the proposed CPS Rule, Boundary Dam's operator filed comments to make clear that "SaskPower's CCS facility **is not capturing 90 per cent** of emissions from Boundary Dam Unit 3."[119] Boundary Dam's operator acknowledged that Unit 3 has experienced constant "technical issues," requiring "consistent[] … modifications … to stabilize operations" and "improve reliability."[120] Indeed, Boundary Dam's operator "concede[s] that a fraction of the flue gas from the

---

[114] 89 Fed. Reg. at 39,850. Plant Barry received EPAct05 funds. *See id.* at 39,849 (heading for EPAct05 assisted projects, with Plant Barry listed therein); *see also* 90 Fed. Reg. at 25,770.

[115] 89 Fed. Reg. at 39,849-50; 90 Fed. Reg. at 25,770-71. Petra Nova received EPAct05 funds. 89 Fed. Reg. at 39,849; 90 Fed. Reg. at 25,770.

[116] 89 Fed. Reg. at 39,849; 90 Fed. Reg. at 25,770.

[117] 89 Fed. Reg. at 39,849; 90 Fed. Reg. at 25,770.

[118] 90 Fed. Reg. at 25,769-70.

[119] SaskPower Comments on Proposed Carbon Pollution Standards at 1, Docket ID No. EPA-HQ-OAR-2023-0072-0687 (Aug. 4, 2023) (emphasis added).

[120] *Id.*

Unit 3 boiler is not processed but bypassed – for the purpose of reliability. The fraction of flue gas bypassed is 5% of total flow."[121] According to experts, the "Boundary Dam experience does not demonstrate CO_2 removal of 90%; rather 65-70% CO_2 can be achieved with a caveat on reliability."[122] These facts and this poor performance cannot support a demonstration that 90 percent CCS is adequately demonstrated.

In addition, Boundary Dam Unit 3 is relatively small—only 110 MW—and therefore is not representative of how CCS might work at a much larger scale. This is particularly important given that CCS is BSER only for long-term coal-fired steam generating units (i.e., those that will operate after January 1, 2039) and for coal-fired steam generating units that undergo a large modification. Owners and operators of coal-fired steam generating units only will be willing to invest the sums of money needed for CCS (or for a large modification) in large units that are run frequently and are needed for base load generation, which means these units are not comparable to Boundary Dam.

In the Carbon Pollution Standards, EPA also cited the Argus Cogeneration Plant at Searles Valley Minerals in Trona, California, as evidence to support its adequately demonstrated determination.[123] That facility captures about "270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW" plant.[124] Critically, though, EPA did not provide information about the percentage of CCS achieved by the facility. Based on the best information available, however, it is apparent that Argus captures far less than 90 percent of the CO_2 generated onsite, with experts estimating a range of capture between 18 and 33 percent.[125] Moreover,

---

[121] C&H 2025 CCS Technical Report at 12.

[122] *Id.*

[123] 89 Fed. Reg. at 39,849.

[124] *Id.*

[125] *See* J.P. Kay, et al., Energy & Environmental Research Center, University of North Dakota, Examination of EPA's Proposed Emission Guidelines Under 40 CFR Part 60 at 5 (Aug. 2023) (estimating 18 percent capture rate for the station) (included as Attachment D to PGen Comments

this facility does not transport or store the CO_2 it does capture, which the CPS Rule requires.[126] The Argus Cogeneration Plan does not support an adequate demonstration finding.

In the Carbon Pollution Standards, EPA also relied on two additional projects to support its adequate demonstration finding: AES Warrior Run and AES Shady Point. Both of these projects are slipstream projects that are intended for research and development. Importantly, they do "not link the reliability of the host process to the CO_2 capture technology—and thus cannot reflect conditions for 24x7 utility power generation demonstration."[127] Just as important, neither project captures anywhere near 90 percent of the CO_2 generated onsite. Warrior Run, which is a 180 MW unit, captures only about 10 percent of its CO_2 emissions[128] and Shady Point, which is a 320 MW unit, captures only about 5 percent.[129] Neither of these projects can be credibly cited as evidence that 90 percent CCS is adequately demonstrated.

In the CPS Rule, EPA also cited some projects that received EPAct funding as "further corroborat[ion]" for its adequate determination findings regarding CCS and steam generating units.[130]

---

on the Proposed Carbon Pollution Standards, which are included in Addendum 2 to these comments); J.E. Cichanowicz, M.C. Hein, Technical Comments on Carbon Capture Utilization and Sequestration Aspects of the Proposed New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule at 3 (Aug. 7, 2023) (estimating 33 percent capture rate for single facility at the station) (C&H 2023 CCS Technical Report) (included as Attachment C to PGen Comments on the Proposed Carbon Pollution Standards, which are included in Addendum 2 to these comments).

[126] TSD - Greenhouse Gas Mitigation Measures for Steam Generating Units, New Source Performance Standards for Greenhouse Gas Emissions from New and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule at 37-38 (Apr. 2024), Docket ID EPA-HQ-OAR-2023-0072-9095 ("GHG Mitigation Measures-Steam TSD").

[127] C&H 2023 CCS Technical Report at 3 n.7.

[128] 89 Fed. Reg. at 39,849.

[129] *Id.*

[130] *Id.* at 39,847-51.

Even if these projects could be considered by EPA in its adequately demonstrated determination—which they cannot—they do not support EPA's BSER finding. The most notable of these EPAct projects is the Petra Nova project near Houston, Texas. Petra Nova is another slipstream project, meaning it "does not reflect actual, full-scale duty if integrated into the host boiler duty cycle ."[131] In the CPS Rule, EPA noted that that Petra Nova "successfully captured 92.4 percent of the CO_2 **from the slip stream of flue gas**."[132] This does **not** mean that Petra Nova supports EPA's 90 percent CCS BSER determination because Petra Nova used CCS only on a portion of its emissions—the slipstream. In truth, Petra Nova captured only about 33 percent of the unit's emissions.[133] Stating the obvious, 33 percent is far less than the 90 percent requirement imposed by the Carbon Pollution Standards.

Like Boundary Dam, Petra Nova has also encountered problems. The plant, which began operation in January 2017, captured far less CO_2 emissions that it had been designed to do, missing its target by about 17 percent, capturing 3.8 million short tons of CO_2 during its first three years of operation, which was less than the 4.6 million short tons that had been expected to be captured.[134] During those first three years of operation, the facility experienced outages on 367 days, with the CCS facility accounting for more than one-fourth of those outages.[135] The project was also dependent on oil prices to be economically viable because the captured CO_2 from the project was used for enhanced oil recovery ("EOR"), and there was no alternate storage option. The project was "impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil," and its

[131] C&H 2025 CCS Technical Report at 13.

[132] 89 Fed. Reg. at 39,850 (emphasis added).

[133] EEI Comments, *supra* note 24, at 72.

[134] *See* N. Groom, Reuters, *Problems plagued U.S. CO2 capture project before shutdown: document* (Aug. 6, 2020), https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-beforeshutdown-document-idUSKCN2523K8.

[135] *Id.*

owner at the time placed the Petra Nova project in reserve shutdown status on May 1, 2020.[136] Although the project was brought back online in 2023, this experience shows how reliance on EOR can increase a project's volatility.

As with Petra Nova, EPA's statement in the CPS Rule is misleading when it said that Plant Barry in Mobile, Alabama, provides an example of a "fully integrated 25 [MW] CCS project with a capture rate of 90 percent."[137] Plant Barry is another slipstream CCS project where only a **fraction** of the facility's CO_2 is captured.[138] Yet again, this example does not support an adequate demonstration finding because it is not of the scale or type to make it comparable to the facilities to which the Carbon Pollution Standards apply, with EPA correctly stating in the Proposed Repeal Rule that "Plant Barry is not reflective of commercial scale operation."[139]

In the CPS Rule, EPA also improperly relied on projects that have not been constructed to support its flawed adequate demonstration findings.[140] Section 111 clearly does not permit EPA to rely on unconstructed projects as evidence a technology is adequately demonstrated. But digging further into some of EPA's cited projects, it becomes clear that even if they were constructed and operating exactly as designed, they would still not support EPA's 90 percent CCS determination. For example, Project Tundra in North Dakota – a project subsidized by DOE that if it is ever built would be the largest CCS project in the United States and one of the largest CCS projects in the world –

---

[136] NRG Energy, Inc., Petra Nova status update: Petra Nova Carbon Capture System (CCS) placed in reserve shutdown (Aug. 26, 2020), https://www.nrg.com/about/newsroom/2020/petra-nova-status-update.html.

[137] 89 Fed. Reg. at 39,850.

[138] PGen Comments on the Proposed Carbon Pollution Standards at 26-27, 34.

[139] 90 Fed. Reg. at 25,770.

[140] 89 Fed. Reg. at 39,850-51 (citing Project Tundra and Project Diamond Vault, which are both in the preconstruction phase of their development, as well as other preconstruction projects that are conducting feasibility work).

would attempt to demonstrate a 70 percent CCS system, a feat that has not been achieved on an EGU of this commercial size anywhere.[141]

Lastly, in the CPS Rule, EPA cited "vendor statements" to support its determination that 90 percent CCS is adequately demonstrated.[142] Although the D.C. Circuit has said that vendor statements might be informative, the court has made clear that they cannot serve as the grounds for an adequate determination finding and that vendor statements "taken alone" as support for a performance standard "would not be decisive."[143]

EPA's determination in the Carbon Pollution Standards that CCS is adequately demonstrated for modified and existing coal-fired steam generating units is unlawful because it is "based on 'crystal ball' inquiry"[144] and "mere speculation or conjecture."[145] There is no evidence that CCS technology can capture 90 percent of the CO_2 emissions from an entire facility (as opposed to a slipstream portion of the facility's emissions) and do so on a consistent basis. Moreover, there is no evidence that these technologies can work on large, commercial-scale EGUs.

2. EPA Correctly Proposes to Find that the Portions of the Carbon Pollution Standards that Are Based on EPA's 90 percent CCS BSER Determination Are Not Achievable (C-23, C-39).

EPA has long held the position that a standard of performance under section 111 "establishes what **every** source can achieve" and is intended to represent the "least common denominator" that

[141] Comments from Minnkota Power Cooperative, Inc. on New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule at 12 (Aug. 8, 2023), Docket ID EPA-HQ-OAR-2023-0072-0632 at 12.

[142] 89 Fed. Reg. at 39,851-52.

[143] *Sierra Club*, 657 F.2d at 364.

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

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

can "be reasonably achieved by [a] new source **anywhere** in the nation."[146] The D.C. Circuit has explained that "[t]o be achievable, … a uniform standard must be capable of being met under **most adverse** conditions which can reasonably be expected to recur."[147] In other words, performance standards are not achievable when, "by design, there are no particular controls a … plant operator can install and operate to attain the emissions limits."[148]

This long-held position also applies to emission guidelines for existing sources under section 111(d) of the CAA where EPA establishes the BSER and sets presumptively approvable performance standards for those sources. In the Carbon Pollution Standards, EPA promulgated NSPS based on a BSER of use of CCS with 90 percent capture of CO_2 for new base load combustion turbines during Phase 2[149] and for modified steam generating units.[150] EPA also issued presumptively approvable performance standards based on a BSER of use of CCS with 90 percent capture of CO_2 for existing coal-fired steam generating units that will operate after January 1, 2039.[151] These NSPS and presumptively approvable emission limitations fail to meet the requirements under section 111 that a standard of performance be achievable "for the industry as a whole."[152]

First, the conclusion in the CPS Rule that emission limitations based on 90 percent CCS are achievable on a sustained basis for new base load combustion turbines, long-term existing coal-fired steam generating units, and coal-fired steam generating units that undergo a large modification has no factual basis whatsoever. EPA does not cite even a single example in the CPS Rule of a commercial

---

146 McCutchen Letter at 1 (emphases added).

147 *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46 (emphasis added).

148 *West Virginia v. EPA*, 597 U.S. 697, 701 (2022).

149 89 Fed. Reg. at 39,917, Table 3.

150 *Id.* at 39,954.

151 *Id.* at 39,958.

152 *Nat'l Lime Ass'n*, 627 F.2d at 431.

scale EGU meeting the NSPS or the presumptive emission standards based on the 90 percent CCS BSER determination. There is a simple explanation for this: it cannot do so because no commercial EGU has ever achieved 90 percent CCS on a continuous basis as the Carbon Pollution Standards requires. As discussed above in Section II.B.1.a, there is only one coal-fired steam generating unit that has ever come close to meeting a 90 percent capture rate (Boundary Dam), and that unit has been plagued with issues, and its own operator says it cannot reliably meet that capture rate. And there are no gas-fired combustion turbines employing CCS at all. This fact alone disqualifies EPA's 90 percent CCS BSER determination and supports EPA's Proposed Repeal Rule. But there are other reasons as well to support EPA's proposed repeal of its prior BSER determination on the grounds that 90 percent CCS is not achievable.

As EPA explains in the Proposed Repeal Rule, "the Agency assumed an aggressive timeline for deployment of" the infrastructure needed to meet the performance standards based on CCS, which includes pipelines to transfer the captured CO_2 to facilities where it can be stored or sequestered underground.[153] As EPA correctly notes, "there is not an existing network of CO_2 pipelines with the capacity capable of meeting the demands in the" Carbon Pollution Standards, and the "existing storage infrastructure for sequestration of CO_2 is limited."[154] These factors make it difficult, if not impossible, to meet the January 1, 2032 date by which the CCS-based standards must be met under the CPS Rule, and EPA is correct in the Proposed Repeal Rule that this renders those standards unachievable.[155]

As EPA admitted in the CPS Rule, many areas of the country do not have ready access to geologic storage for CCS. Indeed, "EPA found that there are 43 states with access to, or are within

[153] 90 Fed. Reg. at 25,773 (steam generating units); *see also id.* at 25,777 ("the timeline in the CPS [Rule] for the design, permitting, and installation of capture, pipelines, and sequestration for new combustion turbines assumes a best-case scenario").

[154] *Id.* at 25,773.

[155] *Id.*

100 [kilometers] [62 miles] from, onshore or offshore storage in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs."[156] For EGUs not immediately near a geologic storage site, the construction of a pipeline to transport the captured CO_2 is necessary in order for the performance standard to be achievable. But the cost to construct a pipeline is very expensive, permitting is a years-long process, and pipelines are met with increasing resistance making permitting in many cases impossible.[157] Indeed, some PGen members have experienced pipeline construction costs in the range of $4 to $10 million per mile. Under EPA's own facts, this means that in seven states, the owners and operators of EGUs will need to construct a pipeline that is at least 62 miles long—with a **starting** cost ranging between $248 and $620 million dollars that will only increase with every additional mile. EPA properly recognizes these difficulties in the Proposed Repeal Rule.[158]

In the CPS Rule, EPA's "solution" to this achievability problem is to suggest that "[e]lectricity demand in areas that may not have geologic sequestration sites may be served by gas-fired EGUs that are built in areas with geologic sequestration, and the generated electricity can be delivered through transmission lines to the load areas through 'gas-by-wire.'"[159] While this might be conceivable for new EGUs, it is faulty on two levels. First, constructing transmission lines is also expensive, takes years to permit, and is often met with public resistance.[160] Second, and more importantly, this "give[s] a

---

[156] 89 Fed. Reg. at 39,930.

[157] *See, e.g.*, I. Penn, NY TIMES, *Atlantic Coast Pipeline Canceled as Delays and Costs Mount* (July 5, 2020), https://www.nytimes.com/2020/07/05/business/atlantic-coast-pipeline-cancel-dominion-energy-berkshire-hathaway.html; C. Davenport, NY TIMES, *Mountain Valley Pipeline Halted as Legal Wrangling Heats Up* (July 12, 2023), https://www.nytimes.com/2023/07/12/climate/mountain-valley-pipeline-courts.html; A. Liptak and A. VanSickle, NY TIMES, *Supreme Court Clears the Way for Pipeline as Appeal Moves Forward* (July 27, 2023), https://www.nytimes.com/2023/07/27/us/supreme-court-mountain-valley-pipeline.html; *see also* 90 Fed. Reg. at 25,773 (discussing problems with Summit Carbon Solutions' pipeline application in South Dakota and Iowa).

[158] 90 Fed. Reg. at 25,773.

[159] 89 Fed. Reg. at 39,931.

[160] J. Weeda, Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on Generation Resource Adequacy and the Need for Transmission Alternatives at 6 (Aug. 3, 2023)

competitive advantage to one State over another in attracting industry," in violation of section 111.[161] Third, this "solution" is completely unworkable for existing coal-fired steam generating units, unless the owner or operator wants to prematurely retire the unit and construct a new one near geologic storage—leading to a state without geologic storage being harmed twice (once when a plant in its borders closes and again when the new construction takes place in another state). And, finally, as EPA notes there is increased line loss (i.e., lost electricity) with longer transmission lines, an issue the Agency did not analyze in the CPS Rule.[162]

As EPA notes in the Proposed Repeal Rule, there are currently approximately 5,000 miles of pipelines in the United States to transport CO_2.[163] But this is an infinitesimal fraction of what is needed. The Congressional Research Service report that EPA cited regarding this issue in the Proposed Repeal Rule said that achieving the prior administration's national goals for GHG reduction would require an additional 66,000 miles of pipelines by 2050, at a cost of "some $170 billion in new capital investment."[164] In the CPS Rule, EPA glosses over the difficulties and hurdles involved in constructing this pipeline network. The Agency also glosses over safety issues for these pipelines, noting almost as an aside that there was a failure of a CO_2 pipeline in Satartia, Mississippi in 2020 and that the Pipeline Hazardous Materials Safety Administration is conducting a rulemaking on safety issues.[165] No mention is made of whether this rulemaking has concluded. Rather, EPA states in a conclusory fashion that

("The experience of the utility sector in recent years shows that building transmission is a challenging multi-year process, and in the more populated areas, it can be nearly impossible.") (Attachment F to PGen Comments on the Proposed Carbon Pollution Standards, which are included in Addendum 2 to these comments).

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

[162] 90 Fed. Reg. at 25,777.

[163] *Id.* at 25,773 (citing Congressional Research Service, Carbon Dioxide Pipelines: Safety Issues at 1 (June 3, 2022), https://crsreports.congress.gov/product/pdf/IN/IN11944) ("CRS Report").

[164] CRS Report at 1.

[165] 89 Fed. Reg. at 39,861.

state and federal pipeline safety standards "ensure that captured CO_2 will be securely conveyed to a sequestration site."[166]

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

3. EPA Correctly Proposes to Find that CCS Is Not Cost-Effective (C-15, C-21, C-22, C-37, C-38).

When EPA sets an NSPS based on its identified BSER and the emission reduction associated with that BSER, Congress required EPA to "tak[e] into account the cost of achieving such reduction."[167] This requirement means that EPA cannot require emission reduction measures that come at an "'excessive' or 'unreasonable'" cost.[168] CCS is prohibitively expensive, and it is not "rational" for EPA "to impose billions of dollars in economic costs in return for a few dollars in … environmental benefits."[169] Prior to the CPS Rule, EPA consistently rejected CCS as too costly in past rulemakings, such as in the Clean Power Plan, for example, where the Agency rejected CCS as a BSER because it would be "substantially more expensive" than the multibillion dollar generation shifting approach included in that rule.[170] Four years later when EPA promulgated the Affordable Clean Energy Rule, its assessment remained unchanged when it found "the high cost of CCS, including the high capital costs of purchasing and installing CCS technology and the high costs of operating it, … prevent CCS or partial CCS from qualifying" as a permissible system under section 111.[171]

---

[166] *Id.*

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

[168] 90 Fed. Reg. at 25,758 (quoting *Sierra Club*, 657 F.2d at 343); 89 Fed. Reg. at 39,832 (same quote).

[169] *Michigan v. EPA*, 576 U.S. 743, 752 (2015).

[170] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, 64,769 (Oct. 23, 2015) (the "Clean Power Plan").

[171] Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, 84 Fed. Reg. 32,520, 32,548 (July 8, 2019) (the "ACE Rule").

In an attempt to find CCS cost-effective in the Carbon Pollution Standards, EPA inappropriately relied on tax credits under the Inflation Reduction Act ("IRA").[172] But tax credits do not **reduce** the costs of CCS; they **transfer** them from power plant owners to taxpayers. Section 111 does not limit its cost-effectiveness requirement only to an examination of those costs a source's owner or operator will bear.

Even assuming for the sake of argument that section 111 allows EPA to take tax credits into account in a cost-effectiveness analysis, obtaining these credits is far from certain. Congress placed significant conditions in the IRA on the ability to obtain them,[173] and nothing would prevent Congress from taking them away. Indeed, this has been recently considered by Congress. Representative Scott Perry introduced a bill on March 6, 2025, called the "45Q Repeal Act of 2025" that would have repealed all of the IRA's tax credits for CCS.[174] Although the CCS tax credits were ultimately preserved in the recently enacted One Big Beautiful Bill ("OBBB") Act,[175] this was not without controversy,[176] and nothing prevents a future Congress from repealing the credits in the future. While the 45Q tax credit received relatively favorable treatment under the OBBB compared to other credits, most other credits were significantly scaled back, which further weakens the flawed rationale in the CPS Rule that CCS is cost-effective.

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

CCS cannot be considered the BSER for fossil fuel-fired EGUs because CCS "give[s] a competitive advantage to one State over another"[177] due to the lack of geological storage across the

---

[172] 89 Fed. Reg. at 39,882.

[173] Under the IRA, an electric generating facility must capture a minimum of 18,750 tons of CO_2 per year and its capture design capacity must be at least 75 percent of the unit's baseline CO_2 production to be eligible to receive tax credits. Pub. L. No. 117-169, § 13104(a).

[174] H.R. 1946, 119th Cong. (Mar. 6, 2025).

nation, the fact that CCS is a water intensive technology that has a large parasitic load, and the fact that it imposes unreasonable costs at the level of individual plants.[178] These additional reasons provide further support for the Proposed Repeal Rule.

a. Geographic and Site Limitations

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

As shown by surveys done by DOE and the U.S. Geological Survey ("USGS"), potential repository sites are not evenly distributed throughout the United States, and many locations throughout the country lack suitable geological conditions for carbon storage.[179] The USGS National Assessment concludes that nearly two-thirds of the technically accessible storage resources in the United States are confined to the Coastal Plains region, with 91 percent of that total limited to a single

[175] Global CCS Institute, U.S. Preserves and Increases 45Q Credit in "One Big Beautiful Bill Act" (8 July 2025), https://www.globalccsinstitute.com/news-media/latest-news/u-s-preserves-and-increases-45q-credit-in-one-big-beautiful-bill-act/.

[176] *See, e.g.*, S. Hanlon, K. Sweeney, The Tax Law Center NYU Law, House-passed tax bill would end many clean energy credits and add unworkable rules to others (May 30, 2025) (noting the bill, as passed by the House, repeals the 45Q tax credits promoting CCS), https://taxlawcenter.org/blog/house-passed-tax-bill-would-end-many-clean-energy-credits-and-add-unworkable-rules-to-others.

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

[178] *Id.* at 330.

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

basin.[180] Another tenth of the nation's potential storage capacity is in Alaska, almost all of which is confined to the remote North Slope.[181] In contrast, the entire Eastern Mesozoic Rift Basin region, which includes several major metropolitan areas along the Eastern seaboard, contains less than 1 percent of the nation's storage capacity.[182]

Moreover, the CO_2 storage at any specific site will not be known until the site is assessed for specific criteria. As DOE noted in the first edition of its North American Carbon Storage Atlas, "[i]t is important that a regionally extensive confining zone (often referred to as caprock) overlies the porous rock layer and that no major faults exist."[183] The North American Carbon Storage Atlas also cites the importance of documenting the CO_2 storage capacity, the "injectivity," and the ability of the porous rock to permanently trap CO_2.[184] All of these criteria are necessary to evaluate the storage potential of a site.[185] Other site-specific items that need to be considered include land-management, regulatory restrictions, and whether the basin contains freshwater that would restrict its use for CO_2 storage.[186]

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

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

[181] *Id.*

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

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

[184] *Id.*

[185] *Id.*

[186] *See* USGS National Assessment at 15.

injection rates over time, "it is likely that only a fraction" of the high-level estimated technically accessible CO_2 storage resources could be available.[187] A formation may have one or more fractures in the caprock or may have well penetrations. A site may have sufficient porosity but low permeability. Current information in most cases would not be sufficient to show whether CO_2 is likely to settle in a broad or narrow depth range, a question that is important to determine how the CO_2 plume will spread and to address displacement of underground fluids. Settlement of CO_2 and displacement of underground fluids factor into the property rights that must be pre-arranged for sequestration. These critical issues require costly, potentially time-consuming research and resolution that takes several years; it can take several years simply to evaluate a site for CO_2 storage potential. If the site proves to be unsuitable for storage after a company has invested years of effort and millions of dollars into the evaluation, the company may have to begin the process all over again with additional time and money.

For example, in the late 2000s, several entities (including PGen members) participated in a CO_2 storage pilot project to investigate the suitability of a formation in the Colorado Plateau region of northeastern Arizona.[188] Five candidate project sites were evaluated prior to the selection of a final test site near Holbrook, Arizona. The project participants held meetings to inform the local community about the project beginning in 2007, obtained the necessary state and federal permits for well drilling and CO_2 injection in 2008-2009, and completed the 3,800 foot well in 2009. After investing over $5.7 million and several years on the project, the participants found that the geological

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

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

formation had insufficient permeability to proceed with CO_2 injection, and the project was discontinued.[189]

Suitable sites for EOR are similarly limited and uncertain. EOR sites are unevenly distributed across the country. DOE estimates that overall EOR capacity for captured CO_2 is only about 10 percent of the capacity estimated for deep saline sequestration.[190] Moreover, as with sequestration, several years of subsurface feature characterization may be required before a site can be assessed as suitable for EOR. These limits are particularly significant because the only commercial utility applications of CCS to date that could be cost-justified have had to rely on EOR. The reliance on EOR, however, renders the operation volatile—as can be seen from the Petra Nova project in Texas, which ceased operations because of an economic downturn at the beginning of the COVID-19 pandemic.[191]

In addition, the lack of availability of the needed geographic criteria cannot be easily solved by the construction of pipelines to move the separated gas to areas of the country that can store the CO_2. There are many hurdles to pipeline construction. First, it is extremely expensive; current pipeline projects for PGen members have cost between $4 to 10 million per mile of pipe. Second, pipeline

---

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

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

[191] *See* NRG Energy, Inc., Petra Nova status update: Petra Nova Carbon Capture System (CCS) placed in reserve shutdown (Aug. 26, 2020) (noting that the plant "has been impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil" and that "[g]iven the current status of oil markets, … [t]he carbon capture facility has been placed in reserve shutdown status to allow it to be brought back online when economic conditions improve"), https://www.nrg.com/about/newsroom/2020/petra-nova-status-update.html.

projects face significant opposition from the public and require extensive permitting that is not easily or quickly obtained.[192]

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

b. Water Constraints

Water provides another reason why EPA's proposed repeal of the CCS requirements in the CPS Rule is well founded. CCS requires significant water for process operation. As EPA has acknowledged, "[a]ll CCS systems that are currently available require substantial amounts of water to operate," which "limit[s] the geographic availability of potential future EGU construction to areas of the country with sufficient water resources."[193] Like sequestration, water resources for use in CCS are severely limited in some parts of the country.

EPA acknowledged in the CPS Rule that CCS increases water consumption at an EGU. For coal-fired steam generating units, EPA estimates an increase in water consumption of 36 percent gross.[194] EPA glosses over this fact and notes that a feasibility study for a project by SaskPower "would rely entirely on water condensed from the flue gas and thus would not require any increase in external water consumption."[195] Citation to a *feasibility study* that plans on trying something for the first time

---

[192] *See* 90 Fed. Reg. at 25,773.

[193] 83 Fed. Reg. 65,424, 65,443 (Dec. 20, 2018); *see also generally id.* at 65,442-44.

[194] 89 Fed. Reg. at 39,885.

[195] *Id.*

does not solve the present problem. Neither is the problem solved by using "dry or hybrid cooling systems" in "[r]egions with limited water supply,"[196] especially when EPA admitted in the proposed CPS Rule that "wet cooling systems can be more effective."[197] EPA then without anything more concludes that it "considers the water use requirements to be manageable and does not expect this consideration to preclude coal-fired power plants generally from being able to install and operate CCS."[198] Acknowledging a problem exists, pointing to a feasibility study for new technology not yet in operation, and noting possible alternatives that are not as effective do not form the basis for a conclusion that the problem is manageable. EPA's conclusion is arbitrary and capricious, and therefore unlawful.

EPA fares no better with regard to water issues resulting from CCS use at gas-fired combustion turbines. There, EPA acknowledges that CCS use at a combined cycle combustion turbine results in "an increase of about 50 percent" in water use.[199] Yet, EPA concludes that "because combined cycle turbines require limited amounts of cooling water, the absolute amount of increase in cooling water required due to use of CCS is relatively small compared to the amount of water used by a coal-fired EGU."[200] EPA also notes that "many combined cycle EGUs currently use dry cooling technologies and the use of dry or hybrid cooling technologies for the CO_2 capture process would reduce the need for additional cooling water."[201] There is no analysis beyond this. For example, there is no discussion of whether CCS can use dry cooling technologies, whether they have been used at combined cycle combustion turbines with CCS (which would be impossible since CCS has never been

---

[196] *Id.* at 39,885-86.

[197] 88 Fed. Reg. at 33,350.

[198] 89 Fed. Reg. at 39,886.

[199] *Id.* at 39,936.

[200] *Id.*

[201] *Id.*

employed at a natural gas combined cycle ("NGCC") unit), or how effective those technologies might be. Nor is there any analysis of how a 50 percent increase in water use affects arid areas of the country. More analysis is required to support EPA's conclusion "that the challenges of additional cooling requirements from CCS are limited and do not disqualify CCS from being the BSER"[202] for gas-fired combustion turbines. EPA's conclusion is unsupported, arbitrary, and capricious.

The D.C. Circuit has previously found that "an efficient water intensive technology … might be 'best' in the East where water is plentiful, but environmentally disastrous in the water-scarce West."[203] Therefore, the court concluded that a water intensive technology could not be selected as the BSER under section 111 because it would have the effect of precluding construction of new sources in states that lack the resources necessary (here, water) to allow compliance with the standard at a reasonable cost.[204] EPA did not explain in the CPS Rule why the court's reasoning in that case does not apply here. EPA's conclusory findings in the Carbon Pollution Standards that water will not be a barrier to the deployment of CCS at coal-fired steam generating units and at NGCC combustion turbines violate section 111. This provides more reasons why EPA's proposed repeal of the CCS requirements in the Proposed Repeal Rule is appropriate.

c. Parasitic Load

There is a significant parasitic load associated with the operation of CCS equipment. In the CPS Rule, EPA estimates the operation of CCS equipment at a new 500 MW combined cycle EGU will de-rate the plant by 11 percent to a 444 MW plant.[205] For coal-fired steam generating units, EPA estimates that the CCS equipment would reduce the output at a 474 MW-net (501 MW-gross) coal-

---

202 *Id.*

203 *Sierra Club*, 657 F.2d at 330.

204 *Id.*

205 89 Fed. Reg. at 39,935-36.

fired steam generating unit by 23 percent to a 425 MW-net unit.[206] For combined cycle units, EPA recommends that a developer simply build a larger plant to compensate for the parasitic load and finds that "[a]lthough the use of CCS imposes additional energy demands on the affected units, those units are able to accommodate those demands by scaling larger, as needed."[207] This does not really address the issue, and EPA's failure to examine the effect of the energy penalty from CCS on those existing units is arbitrary and capricious.

EPA does not make any recommendation for existing coal-fired steam generating units; for those units, EPA simply states that it "considers the energy penalty to not be unreasonable and to be relatively minor compared to the benefits in GHG reduction of CCS."[208] EPA's analysis misses the mark. The parasitic load associated with CCS is not minor: it amounts to 25 to 30 percent.[209] As discussed above in Section I, electricity demand in the United States is growing rapidly, resulting in the electricity grid becoming strained and reliability being increasingly threatened. Installing CCS on existing coal-fired EGUs and new base load combustion turbines will exacerbate this reliability problem because a large percentage of the energy being generated by those EGUs will now be needed to power the CCS technology at power plants rather than being available to consumers. Section 111 requires EPA to examine energy requirements when setting an NSPS, which EPA did not do in the Carbon Pollution Standards. Where, as here, the agency has "failed to consider an important aspect

[206] *Id.* at 39,883.

[207] *Id.* at 39,936.

[208] *Id.* at 39,883.

[209] D. Walsh, Analysis of EPA's Proposed Construction Timeframes for CCS Projects at 4 (Aug. 3, 2023) (Attachment G to PGen Comments on the Proposed Carbon Pollution Standards, which are included in Addendum 2 to these comments).

of the problem," the action is arbitrary and capricious.[210] This provides additional support for EPA's proposed repeal of the CCS requirements.

C. The Determination in the CPS Rule that the BSER for Existing "Medium-Term" Coal-Fired Steam Generating Units is Co-Firing with 40 percent Natural Gas Does Not Comply with Section 111's Requirements, and EPA Properly Proposes to Repeal This Determination (C-24, C-28, C-29, C-30).

In the Proposed Repeal Rule, EPA notes that the Carbon Pollution Standards' determination that co-firing with 40 percent natural gas is the BSER for existing medium-term coal-fired steam generating units "constitutes generation shifting and is therefore beyond the EPA's authority to require under CAA section 111."[211] The Carbon Pollution Standards' determination that co-firing with 40 percent natural gas is a BSER explicitly requires shifting energy generation from coal to gas, precisely what the Supreme Court said EPA cannot do.[212] The Supreme Court made clear in *West Virginia* that EPA has no authority to require a plant to change fuel type by switching 40 percent of its generation from coal to gas.[213] It does not matter whether the facility co-fires natural gas at 40 percent or if it would be required to fire 100 percent natural gas to comply with the standard. Impermissible fuel switching occurs any time EPA would require a change from one fuel type to an entirely different fuel type, as the standard here requires. Indeed, for an existing plant, the transformation of the source is particularly stark: The CPS Rule requires any coal-fired EGU that wants to operate beyond January 1, 2032, to make changes to the facility's boiler, including "possible modifications" to millions of dollars of equipment such as the "steam superheater, reheater, and

---

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

[211] 90 Fed. Reg. at 25,774.

[212] *West Virginia*, 597 U.S. at 728-29.

[213] *See id.* at 728 n.3 (expressing "doubt" EPA could "requir[e] coal plants to become natural gas plants").

economizer heating surfaces that transfer heat from the hot flue gas."[214] The work to make these modification possible would takes years of engineering work and studies.[215]

Even if this form of fuel switching were legally permissible, which it is not, the emission limit based on 40 percent co-firing is not currently achievable because the majority of coal plants do not have access to natural gas. While there may be a sufficient natural gas supply in the United States, natural gas co-firing is not sufficiently and uniformly available across the fleet of existing coal-fired steam generating units. In 2017, approximately just one-third of coal-fired EGUs co-fired with **any** amount of natural gas.[216] That number has not changed appreciably since that time. Moreover, the number of plants that co-fire natural gas in significant amounts, as contemplated by the CPS Rule, is minuscule—just four percent.[217] The vast majority of EGUs with co-firing capability only use natural gas at very low levels, primarily for the boiler startup or for holding it in "warm standby."

In addition, the 40 percent co-firing BSER is not cost-effective because of the need to construct pipeline infrastructure. For those coal-fired EGUs that do not have access to natural gas, co-firing would be cost prohibitive because the cost of gaining access to a pipeline is very expensive. EPA explained in the Carbon Pollution Standards that the average cost for a pipeline "within the contiguous U.S. is approximately $280,000 per inch-mile" in 2019 dollars.[218] The average diameter for

---

[214] GHG Mitigation Measures-Steam TSD at 9.

[215] *Id.*; W. Morris & J. Weeda, Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on the Generation Alternative of Fuel Switching to Natural Gas at 8 (Aug. 3, 2023) (Attachment K to PGen Comments on the Proposed Carbon Pollution Standards, which are included in Addendum 2 to these comments).

[216] 84 Fed. Reg. at 32,544.

[217] *Id.* ("very few—less than four percent of coal-fired units—co-fired with natural gas in an amount greater than five percent of the total annual heat input").

[218] 89 Fed. Reg. at 39,894.

a natural gas pipeline is 18.3 inches.[219] This means that the average cost of an average size pipeline in the United States is $5,124,000 per mile.

Because the 40 percent gas co-firing requirement constitutes impermissible generation shifting, requiring a coal-fired power plant to become a hybrid plant that combusts both coal and gas, because the vast majority of coal-fired EGUs do not have access to natural gas (or access to enough natural gas to co-fire at the levels required by the Carbon Pollution Standards), and because constructing the infrastructure needed to co-fire is not cost-effective, EPA properly proposes to repeal its prior determination in the CPS Rule that 40 percent natural gas co-firing is the BSER for medium-term coal-fired steam generating units.[220]

D. Existing Gas- and Oil-Fired Steam Generating Units (C-31)

In the Proposed Repeal Rule, EPA proposes to repeal the emission guidelines for existing gas- and oil-fired steam generating units.[221] PGen agrees with this proposal. As EPA notes, there are very few of these units in the United States, and it "would be imprudent to require States to develop State plans solely for these units."[222] The BSER for these units is, as EPA notes, "consistent with what most sources were already doing (i.e., business as usual), there was no additional cost associated with them, and they resulted in a degree of emission limitation that would have resulted in few, if any, emission reductions for any of the units."[223] Given this set of facts, continuing to regulate these units would not be cost-effective. If regulating these units "would most likely have no significant benefit,"

[219] GeoCorr Blog, *Pipeline Projects Vary by Diameter Across the United States* (Aug. 9, 2021), https://blog.geocorr.com/pipeline-projects-vary-by-diameter-across-the-united-states (noting the "reported projected average diameters for pipelines of different projects through 2035" including natural gas pipelines).

[220] *See* 90 Fed. Reg. at 25,773-75.

[221] *Id.* at 25,775.

[222] *Id.*

[223] *Id.*

as EPA finds,[224] then regulating them is not cost-effective. States will need to expend resources to develop plans, and owners of these units will need to comply with monitoring and other recordkeeping requirements. These costs outweigh the benefits, which are most likely to be zero.[225] As a result, this part of the emission guidelines is not cost-effective.

In addition, the emission guidelines are not necessary. Because the BSER is consistent with business as usual, there is no need for EPA to retain the emission guidelines for these units. As a result, EPA should finalize this portion of the Proposed Repeal Rule.

E. The Major Questions Doctrine Also Supports the Alternative Proposal.

In *West Virginia v. EPA*, the U.S. Supreme Court—in examining the Clean Power Plan, EPA's first attempt at regulating existing fossil fuel-fired EGUs under section 111(d)—held that "there are 'extraordinary cases' that call for a different approach" than deferring to an administrative agency like EPA.[226] These are cases "in which the 'history and the breadth of the authority that [the agency] has asserted,' and the 'economic and political significance' of that assertion, provide a 'reason to hesitate before concluding that Congress' meant to confer such authority."[227] Although the Court had applied this rationale in previous cases, it officially referred to this principle as the "major questions doctrine" for the first time in that case. As detailed below, this same reasoning applies to render the Carbon Pollution Standards to be beyond any direct mandate that EPA has received from Congress and provides additional support for EPA's Alternative Proposal.

In the Clean Power Plan, EPA proposed an approach known as "generation shifting," which prioritized non-GHG emitting electricity generating sources such as wind and solar over low-GHG

---

[224] *Id.*

[225] *See Michigan v. EPA*, 576 U.S. at 752.

[226] *West Virginia*, 597 U.S. at 721 (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159 (2000)).

[227] *Id.*

emitting natural gas-fired generation, and lastly, coal-fired generation (which has higher GHG emissions than gas-fired generation). The Supreme Court, in *West Virginia*, determined that the Clean Power Plan's approach violated the major questions doctrine for four reasons. First, the Court noted that the Clean Power Plan significantly deviated from all previous rules by EPA under section 111(d) and found that:

> Prior to 2015, EPA had always set Section 111 emissions limits based on the application of measures that would reduce pollution by causing the regulated source to operate more cleanly…. It had never devised a cap by looking to a "system" that would reduce pollution simply by "shifting" polluting activity from dirtier to cleaner sources.[228]

The Court found this departure from established practice to be "unprecedented," stating that EPA's authority "effected a 'fundamental revision of the statute, changing it from [one sort of] scheme of regulation' into an entirely different kind."[229] This new interpretation would allow EPA to "demand much greater reductions in emissions based on a very different kind of policy judgment that it would be 'best' if coal made up a much smaller share of national electricity generation. And on this view of EPA's authority, it could go further, perhaps forcing coal plants to 'shift' away virtually all of their generation—i.e., to cease making power altogether."[230]

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

---

[228] *Id.* at 725 (internal quotation and citation omitted).

[229] *Id.* at 728 (quoting *MCI Telecomms. Corp. v. AT&T*, 512 U.S. 218, 231 (1994)).

[230] *Id.*

regulatory development.'"[231] The Court found "little reason to think Congress assigned such decisions" that are outside EPA's expertise to the Agency, and "'[w]hen [an] agency has no comparative expertise' in making certain policy judgments, [the Court has] said, 'Congress presumably would not' task it with doing so."[232]

Third, the Supreme Court expressed its skepticism of EPA's "generation shifting" approach "find[ing] it 'highly unlikely that Congress would leave' to 'agency discretion' the decision of how much coal-based generation there should be over the coming decades," especially "in the previously little-used backwater of Section 111(d)."[233] The types of "basic and consequential tradeoffs" that would be required in making such a decision "are ones that Congress would likely have intended for itself."[234]

Finally, the Supreme Court found it significant that Congress had "'considered and rejected' multiple times" proposals to amend the CAA to establish a cap-and-trade program such as that promulgated in the Clean Power Plan or "to enact similar measures, such as a carbon tax."[235] For all these reasons, the Court concluded that the major questions doctrine was applicable. The Court held that section 111(d) does not contain the "'clear congressional authorization'" to regulate in the manner that EPA attempted to do under the Clean Power Plan.[236]

As outlined below, the Carbon Pollution Standards failed to address the legal deficiencies identified by the Supreme Court in *West Virginia*. Consequently, the Carbon Pollution Standards

---

[231] *Id.* at 729 (quoting EPA, Fiscal Year 2016 Justification of Appropriation Estimates for the Committee on Appropriations 213 (2015)) (emphasis in original).

[232] *Id.* (quoting *Kisor v. Wilkie*, 139 S. Ct. 2400, 2417 (2019)).

[233] *Id.* at 729-30 (quoting *MCI*, 512 U.S. at 231)).

[234] *Id.* at 730.

[235] *Id.* at 731.

[236] *Id.* at 732 (quoting *UARG v. EPA*, 573 U.S. at 324).

violate the major questions doctrine and are unlawful. Although the Clean Power Plan was more transparent with regard to its generation shifting approach and its objective to reduce fossil fuel-fired electric generation,[237] the Carbon Pollution Standards yield an identical outcome— a shifting away from fossil fuel-fired generation (and the conversion of coal-fired units into hybrid-gas-fired ones). This is ultimately a dictation of what EPA views as the optimal mix of energy sources in the United States, with the EPA effectively (and in violation of *West Virginia*) using the CPS Rule to federally mandate a de facto decarbonization renewable portfolio requirement on the electric generation on a national level.

First, although EPA based the Carbon Pollution Standards on emissions reducing technologies and "measures that would reduce pollution by causing the regulated source to operate more cleanly,"[238] the reality is that, as discussed above in Section II.B.1, CCS technology is not yet adequately demonstrated, not achievable, and is not cost-effective, and as discussed above in Section II.C, in addition to being overt generation shifting, co-firing with 40 percent natural gas is not achievable and is not cost-effective. The reliance in the Carbon Pollution Standards on technologies that are currently not in widespread commercial use and on infrastructure that will take many years to build creates significant uncertainty for utilities in resource planning and development. Utilities must contend in the resource planning process with any impacts caused by compliance with the Carbon Pollution Standards, including impacts on cost-effectiveness, quality of power, and reliability, and the injection of such assumptions and uncertainties hinders the ability of electric generators to engage in prudent planning.

Moreover, even if CCS technology were to become adequately demonstrated, achievable, and cost-effective (which is not currently the case), the timetable in the Carbon Pollution Standards for

---

[237] *Id.* at 730-31.

[238] 90 Fed. Reg. at 39,827 (quoting *West Virginia*, 597 U.S. at 725).

implementing these technologies and measures is impracticable at best. Consequently, owners and operators face limited options, being forced to either prematurely retire their units or drastically reduce their usage to comply with the standards.

Second, the Carbon Pollution Standards continue to force EPA's view of the optimal mix of energy sources within the United States, a prerogative that the Supreme Court has determined is not within EPA's authority. The Agency continues to prioritize renewable and non-GHG emitting forms of electric generation over fossil fuel-fired generation. Consequently, the Carbon Pollution Standards effectively result in EPA, once again as it did with the Clean Power Plan, dictating what it believes the optimal mix of electric generation should be in the United States: minimal to no reliance on coal-fired generation, with gas-fired generation reserved only for peak demand and as a backup for renewable generation. This action directly violates the major questions doctrine.

An owner or operator that intends to keep a coal-fired unit operating beyond 2039 must begin complying with an emission limit based on CCS starting in 2032.[239] First, as explained in Section II.B, CCS is neither adequately demonstrated nor achievable, and the timeframe for compliance under the CPS Rule is entirely unrealistic. In effect, this compels owners or operators of coal-fired units either to commit to retire them before 2032, or commit to retire them before 2039 if the unit is fortunate enough to have access to enough natural gas to co-fire at the 40 percent level. These forced early retirements will also result in the retirements of EGUs that recently installed costly emission control equipment, resulting in stranded investments. To the extent the Carbon Pollution Standards take away from the state and local commissions and boards the decision over when a unit should retire, this is also a violation of the major questions doctrine. And if EPA's response is that states would have the option invoking the provisions of the CAA that allow the consideration of remaining useful life and

[239] 40 C.F.R. § 60.5740b(a)(5)(i)(G)(2).

other factors ("RULOF")[240] to avoid early retirement, that argument is a fallacy. EPA has placed restrictions on the use of RULOF that render that provision useless.[241]

The situation is similar for new gas-fired EGUs. The Carbon Pollution Standards effectively limit the construction of units solely for "peaking" purposes to backup renewable generation. Construction of a base load unit that will operate above 40 percent of its capacity factor requires a unit to install CCS by 2032 (which, as discussed in Section II.B.1, is something that has never been done at a combustion turbine to date).

Permanently ceasing operation of viable generation resources is not what Congress had in mind when it enacted section 111, and Congress has not passed any subsequent legislation suggesting or requiring such a drastic step. By essentially requiring the early retirement of existing coal-fired EGUs, the Carbon Pollution Standards go beyond the generation shifting regulations of the Clean Power Plan that were rejected by the Supreme Court. Section 111 does not contain language that provides retirement of existing facilities as an option for a standard of performance, and before EPA can put in place a program that essentially mandates the retirements of coal-fired EGUs, Congress needs to have spoken clearly that this is what it intended for EPA to do, and Congress has not done so. Similarly, Congress needs to have spoken explicitly before EPA can be deemed to have authority under section 111 to authorize limits to operation (i.e., a capacity factor limitation) as the Carbon Pollution Standards do for gas-fired combustion turbines, or by forcing substantial use of an alternate

[240] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1) (requiring EPA to "permit the State in applying a standard of performance to any particular [existing] source under a plan submitted [under this provision] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies").

[241] *See, e.g.*, 89 Fed. Reg. at 39,836 (discussing EPA's restrictions on RULOF).

fuel (40 percent natural gas at a coal-fired unit) during a period of years preceding a mandated date for ceasing operation.

Third, it continues to be "'highly unlikely that Congress would leave' to 'agency discretion' the decision of how much coal-based generation there should be over the coming decades," and the provision of the CAA on which EPA relies as the authority for the Carbon Pollution Standards continues to be "the previously little-used backwater of Section 111(d)."[242]

Fourth, Congress continues to grapple with the issue of climate change and how to best address it cohesively and on a national scale. Consistently, Congress has rejected programs resembling the Carbon Pollution Standards, which would significantly restrict fossil fuel-fired electric generation in the United States.[243] While Congress recently passed the IRA, this statute primarily focuses on subsidizing and promoting the development of nascent technologies such as CCS, which is mandated in the Carbon Pollution Standards, and hydrogen co-firing.[244] Once the IRA funds have been deployed to this end and if these technologies are indeed proven to be adequately demonstrated, achievable, and cost-effective, then it would be appropriate for EPA to evaluate them as potential BSERs for fossil fuel-fired EGUs. However, this milestone has not been reached at present.

For all these reasons, the Carbon Pollution Standards violate the major questions doctrine. EPA's Alternative Proposal, however, would remove from the Standards those requirements (CCS

---

[242] *West Virginia*, 597 U.S. at 730.

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

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

and natural gas co-firing) that run afoul of the doctrine. If EPA were to finalize the Alternative Proposal and include the modifications to the NSPS for intermediate load and Phase 1 base load combustion turbines as PGen suggests in Section III of these comments, the remaining portions of the Carbon Pollution Standards would be based on a system of emission reduction that is adequately demonstrated, achievable, and cost-effective. And with regard to the repealed emission guidelines for existing steam generating units in Subpart UUUUb, section 111(d) does not contain a deadline for EPA to establish emission guidelines for existing EGUs, which provides EPA with the opportunity to prudently wait until these technologies undergo further development before considering whether to mandate their implementation.

III. Under the Alternative Proposal, EPA Should Reconsider the CO_2 Emission Standards for Combustion Turbines at Intermediate Load and Base Load (Phase 1) (C-13, C-14).

EPA should reconsider the current CO_2 emissions standards for combustion turbines in the intermediate load and base load subcategories. These standards are deeply flawed, because (1) they rely on a BSER approach that is likely unlawful or, at least, misguided as a matter of policy and unreasonable; and (2) within that approach, they rely on data for units that are not representative of either source category. Moreover, the operational threshold that distinguishes between the two subcategories is arbitrary.

A. EPA Should Reconsider Its Phase 1 BSER Approach and Establish a Single, Input-Based CO_2 Emission Standard for Combustion Turbines.

1. EPA's Phase 1 BSER for Non-Low-Load Combustion Turbines Inappropriately Incorporates Operating and Ambient Conditions.

EPA has tried multiple times to establish GHG emission standards for EGUs. The reason for EPA's continued challenge in this task is a fundamental fact that distinguishes this NSPS from any other NSPS ever promulgated by EPA. For virtually every NSPS promulgated by EPA (other than this one) over more than a half century of the CAA's history, EPA could identify an adequately demonstrated add-on emission control technology as BSER, and it then would base the NSPS at a level of pollutant emission reduction that is achievable using that technology "under most adverse conditions which can reasonably be expected to recur."[245] Indeed, as the D.C. Circuit explained, there are basic "common threads" in evaluating (and therefore, for the agency to set) BSER and a standard based on such BSER.[246] "Chief among these common threads is a concern that the Agency consider the representativeness for the industry as a whole of the tested plants on which it relies, at least where its central argument is that the standard **is** achievable because it **has** been achieved (at the tested plants)."[247] For the agency to meet this standard, it must:

> first, identify[] and verify[] as relevant or irrelevant specific variable conditions that may contribute substantially to the amount of emissions, or otherwise affect the efficiency of the emissions control systems considered. And second, where test results are relied upon, it should involve the selection or use of test results in a manner which provides some assurance of the achievability of the standard for the industry as a whole, given the range of variable factors found relevant to the standards' achievability.[248]

The quintessential add-on control BSER in the electric generating industry is a scrubber (for control of SO_2), selective catalytic reduction (SCR, for control of NOx), or an electrostatic precipitator (ESP, for control of particulate matter). These add-on controls can, at least to some extent, be dialed up or dialed down to meet the NSPSs based on them. Accordingly, for these pollutants, EPA may identify the BSER (i.e., the technology), identify a highly performing unit, adjust the latter's performance to account for "the range of variable factors found relevant to the standards' achievability," and then select the standard on those bases.[249] What the NSPS means, in essence, is

---

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

[246] *Id.* at 432.

[247] *Id.* at 432-33.

[248] *Id.* at 433.

[249] *Id.*

that any new unit must install the BSER technology (or some equivalent technology) and use it to achieve the same level of effectiveness as the high-performing unit that EPA identified as the basis for the standard. In other words, the implicit logic of NSPS (other than this one) is that if **a** unit can achieve a relatively low rate of emissions of the pollutant at issue using certain control technology, then **any** new unit should be able to – and must – meet a standard based on the performance of that high-performing unit (adjusted for reasonable adverse conditions).

The problem here is that there is no adequately demonstrated add-on technology that can be installed on a combustion turbine and dialed up or down to meet the CO_2 standard EPA would set. Here, if a 12-month rolling average efficiency-based standard is set based on the past performance of a unit, even **that unit** may be unable to meet that standard if it were operated differently (e.g., it experiences more startup and shutdown cycles, load change cycles, or operations at lower levels than in the past) or even if it were operated under different ambient conditions, such as altitude or ambient temperature.

What EPA has done for the Phase 1 standards for non-low-load combustion turbines is to identify "lower-emitting fuels" and "highly efficient generation" as the BSER.[250] This would have been acceptable had EPA based the standard on an input-based limit (as it did for low-load combustion turbines) and/or on the inherent efficiency (heat rate) of the combustion turbine.[251] But EPA went further in the Carbon Pollution Standards rulemaking, and it set the standard for intermediate load and base load combustion turbines as a 12-month rolling average CO_2 emission rate (expressed as lb CO_2/MWh). For a given fuel, however, the average CO_2 emission rate over any time period is a

[250] 89 Fed. Reg. at 39,917 Table 3.

[251] By design, any combustion turbine has an inherent (or specification) heat rate under any specified conditions. Generally, combustion turbine manufacturers specify the design (or inherent) heat rate of the turbine under International Organization for Standardization (ISO) conditions, at full load.

function of not just the inherent heat rate of the combustion turbine at a specified set of conditions, but also a myriad of actual operational and ambient conditions.

> At any given point in time, … the thermal efficiency of the [combustion turbine] is affected by a multitude of factors, among them: (1) the operating level; (2) degradation between maintenance cycles; (3) altitude; (4) ambient temperature; and (5) design margin. Simple-cycle [combustion turbines] are also affected by inlet/outlet losses, while combined-cycle [combustion turbines] are also affected by air inlet fouling and condenser conditions.[252]

If EPA were setting a "normal" NSPS, EPA would have accounted for "the range of [the above] variable factors found relevant to the standards' achievability" to set an emission standard based on the efficiency BSER.[253] That is, EPA would have based the NSPS on the performance of the best-performing units, adjusted to account for the potential, worst case "(1) operating load [and other operational factors, such as start-up and load change cycles]; (2) [reasonable] degradation (both unrecoverable and between maintenance cycles); (3) altitude; (4) ambient temperature; (5) design margin[; (6)] … inlet/outlet losses [(for simple-cycle turbines) and (7)] … air inlet fouling and steam condenser conditions [(for combined-cycle units)]."[254] In the Carbon Pollution Standards rulemaking, however, EPA essentially incorporated these variable factors **into** the BSER by implicitly defining the BSER not as "highly efficient operation," but as "highly efficient operation **accompanied by certain limits on that operation**." In other words, by basing the 12-month rolling average CO_2 standard for intermediate load (and base load, separately) combustion turbines on the performance of one or more existing units with relatively low measured CO_2 rates, it made all the variable factors that affect those units' CO_2 rate part of the BSER, instead of accounting for the range of these variable factors that are

[252] J.E. Cichanowicz, M.C. Hein, Analysis of Combustion Turbine CO_2 Emission Rates Under the 2024 2024 Greenhouse Gas (GHG) New Source Performance Standard (NSPS) for Fossil-Fired EGUs at 4 (Aug. 2025) ("C&H Report") (Attachment 2 to these comments).

[253] *See Nat'l Lime Ass'n*, 627 F.2d at 433.

[254] *See* C&H Report at 4.

clearly relevant to the standards' achievability in setting the standard. The net effect of this approach is that EPA's intermediate load and base load standards mandate not only how inherently efficient the turbine design must be, but **how** and under what conditions they **may** operate.

PGen respectfully submits that this is unlawful. By specifying **how** a combustion turbine may or may not operate, EPA is making energy production decisions that the Supreme Court has made clear are beyond EPA's authority.[255]

2. EPA's Should Establish a Single, Input-Based CO_2 Emission Standard for All Combustion Turbines.

Even if EPA's previous approach to standard-setting for combustion turbines is not unlawful, it should be abandoned in light of the significant energy (and cost) implications of the standard. That is, even assuming EPA can shift the variable factors that affect a combustion turbine's CO_2 emission rate into the BSER, EPA must ask itself whether that is a reasonable thing to do. It is evident, as an initial matter, that EPA cannot – and certainly should not – incorporate factors that are inevitable and/or entirely outside the control of the operator in the BSER. Many factors that affect a unit's CO_2 rate are in this category, namely: (1) operating/cycling profile; (2) inevitable unrecoverable degradation as well as a reasonable amount of degradation between maintenance cycles; (3) altitude; (4) ambient temperature; (5) a reasonable design or compliance margin; (6) inevitable inlet/outlet losses (for simple-cycle turbines); and (7) inevitable air inlet fouling and condenser condition impacts (for combined-cycle) units.

The most important factor affecting a combustion turbine's 12-month rolling average CO_2 rate is, however, **how** the unit is operated. In a vacuum and ignoring reliability-driven operating requirements, an operator surely can control the number of startup/shutdown cycles, the frequency

---

[255] *See West Virginia*, 597 U.S. at 697.

and rate of load change, and the load level at which a combustion turbine operates at any given time.[256] But this requires ignoring the principles of economic dispatch and the fundamentals of balancing the power grid. Accordingly, **should** an NSPS be based on command-and-control of this factor? The answer is no, because the energy implications (as well as costs) of operating a combustion turbine in any way other than what the grid demands and what is required to maintain reliability and grid stability, all in accordance with economic dispatch principles, are highly consequential and potentially dangerous. In other words, is it reasonable for the effect of the standard to be that a simple-cycle turbine must remain idle even though it is needed to stabilize the grid or avoid service interruptions on a very hot day or in the dead of winter, because having one more startup/shutdown cycle in the current 12-month period would result in exceeding the CO_2 standard? Or should a combined-cycle combustion turbine be required to shut down rather than operate at minimum load for spinning reserve, because the latter cannot be achieved without exceeding the CO_2 standard? Requiring such a combustion turbine to shut down would, at best, result in a more costly (and, therefore, possibly more polluting) unit to operate to replace the turbine's output (even if at minimum load). At worst, there are no other power assets to be found, which threatens reliability and grid stability.

PGen submits that how an EGU is operated (which must by necessity respond to demand in the electric generating industry) should not be part of the BSER. EPA must take it as it is, not impose a BSER and standard that, in effect, dictate how a unit must operate. For this reason, EPA should return to basics: PGen agrees the BSER for combustion turbines consists of (1) "lower-emitting fuels" and (2) "highly efficient generation."[257] The former can be established through an input-based

[256] Arguably, this is possible, but unlike other industrial sources that could choose whether to run hard or not on any given day, power generation is responsive to demand in the moment. The operator of an EGU cannot choose to continue operation at full load (for the sake of emission limitations that govern efficiency) when the power grid does not need that electricity.

[257] 89 Fed. Reg. at 39,917 Table 3.

standard, just as it was for combustion turbines operating at low load. The latter should not be based solely on the inherent efficiency (i.e., heat rate) of the combustion turbine. To guard against operators allowing their units to degrade due to lack of maintenance or other operator-controlled condition, EPA could establish a standard that allows no more than a given percentage of heat rate degradation at any time, enforced through an initial heat rate compliance test and a recurring, annual heat rate test.

B. If EPA Retains Emission Standards Expressed in Terms of lb CO_2/MWh on a 12-Month Average Rolling Basis for Combustion Turbines, EPA Should Reconsider the Phase 1 Standards for Combustion Turbines at Intermediate Load and Base Load.[258]

1. The Current Emission Standards for Intermediate Load Combustion Turbines Are Deeply Flawed Because They Are Unachievable by a Number of Highly-Efficient Turbines on the Market.

The intermediate load combustion turbine standards are, in effect, designed to apply to combustion turbines operating in simple-cycle mode at annual capacity factors exceeding 20 percent (and up to 40 percent). In setting a standard for these types of units, EPA entirely ignored that combustion turbines currently available on the market are available in several distinct models (or classes, as they are commonly referred to in the industry) with different characteristics. In general, combustion turbine designs include:

- Aeroderivative units: these are relatively small units – generally smaller than about 125 MW, with the majority (in the electric generating industry) in the 30-100 MW range – with a design often described as that of a jet engine.
- E-Class "frame" turbines, with capacities generally in the 90-150 MW range.
- F-Class frame turbines (and similarly size CTs, e.g., G-Class frame turbines), with capacities in the 200-320 MW range.

---

[258] This section of the comments and the technical study upon which it relies address combustion turbines firing natural gas; this section does not address combustion turbine performance of and CO_2 rates from, combustion turbines when firing diesel oil. *See* C&H Report at 1 (stating that report addresses natural gas-fired combustion turbines and noting that "[s]imilar concepts would apply to other fuels, including diesel oil"). This is primarily due to time constraints, and not because the standards applicable to oil-fired combustion turbines should not also be carefully reconsidered. While oil is not used extensively for combustion turbines in the United States, it is a crucial fuel for areas of the country where gas supply is limited during the winter to ensure its availability for home heating.

- H-Class frame turbines (and similar large CTs, e.g., J-Class frame Turbines) are the largest combustion turbines on the market, with capacities generally above 320 MW.

These various turbine models have been developed by manufacturers for different reasons, and each meets particular market needs and/or design imperatives. There are many potential use cases for combustion turbines: black start capability, peaking and grid reliability, or ancillary services such as frequency response, to name a few. Each use case will prioritize different qualities in a combustion turbine: startup speed, ramp rate, minimum stable load, dual-fuel capability, capital cost per installed MW of capacity, heat rate, and maintenance considerations. For example, if the turbine is intended to serve grid reliability and respond to large peaks in electricity demand, a larger frame turbine such as an F-class or H-class may be appropriate, given the lower capital cost per MW and greater longevity compared to aeroderivative turbines. On the other hand, aeroderivative turbines are often preferred if they will be expected to start up many times per day, because they can withstand the thermomechanical fatigue of frequent starts much better than large frame turbines. In another example, if black start capability is required (i.e., the ability to start up during a total blackout of the grid), an aeroderivative may be a good choice due to the low amount of energy required to start up. Some use cases require a turbine model that can fire liquid fuel in the event of natural gas shortages. There may also be site-specific factors in play, such as constraints on water use, transmission capacity, or physical footprint, that dictate which models can be considered for a given project. In short, the various combustion turbine models on the market exist for a reason. The NSPS should not be set in a way to preclude the use of some of these models.

To this point, the overarching flaw in EPA's Phase 1 standards for combustion turbines is EPA's failure to recognize that each standard EPA sets is applicable, and thus must be achievable, by each of the several turbine classes within the entire subcategory, not just the models upon which EPA happened to base the standard. A second overall flaw is that EPA assumed that previous uses of combustion turbines necessarily define the entire universe of all potential future uses of these turbines. As a result, EPA in effect selected standards that lock in these historic use patterns and effectively function as prohibitions on some models being used in certain applications.

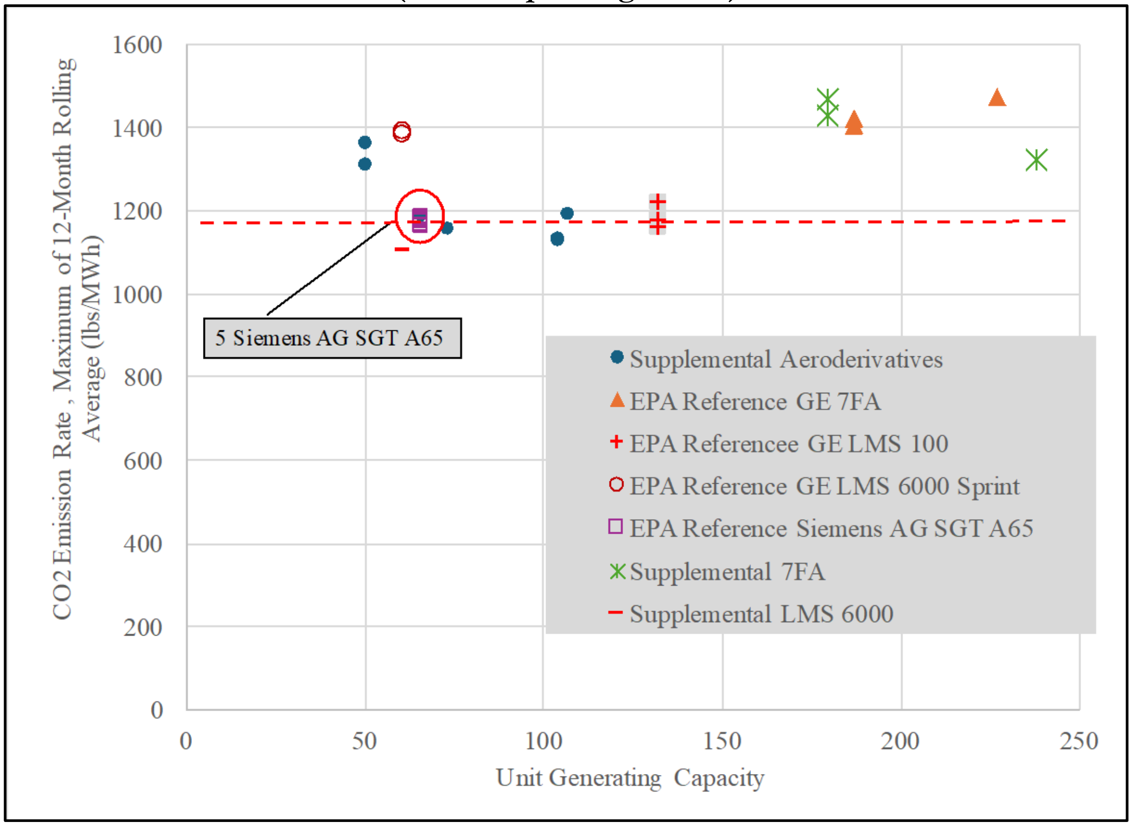
a. EPA based the standard for simple-cycle combustion turbines operating at intermediate load on the performance of a handful of units that are not representative of the variety of highly-efficient units available on the market.

The flaws of EPA's approach are starkly evident in EPA's evaluation and standard setting for simple-cycle combustion turbines in the intermediate load subcategory. For this subcategory, EPA considered an existing dataset of simple-cycle units operating at intermediate load, which consisted of a small number of units, most of which were small aeroderivative turbines. Based on this dataset, EPA selected a CO_2 standard for natural gas-fired combustion turbines of 1,170 lb CO_2/MWh (on a 12-month average rolling basis). By EPA's own recognition, this standard would have been met by a majority of, but not all, turbines in the dataset within the following aeroderivative models: Siemens AG SGT-A65; GE LMS100; and GE LM6000.[259] These aeroderivative units range in size between about 50 MW and 115 MW. The performance of the units upon which EPA based the standards, as well as a handful of additional units identified and analyzed in the C&H Report,[260] are depicted in Figure 1.

[259] *See id.* at 17.

[260] *See id.*

Figure 1 – CO_2 Emissions Rate vs. Nameplate Capacity: 30 Simple Cycle Units Operating Between 20 and 40% Capacity Factor (C&H Report Figure 3-3)



The data in the chart above show that (1) not all units of the models selected by EPA met the rate EPA chose as the standard for this subcategory; (2) a substantial majority of units in the dataset did **not** meet the standard selected by EPA, including the majority of aeroderivative units in the dataset; and (3) all of the handful of frame units in the dataset emitted at rates well above the rate selected by EPA as the standard.[261] Arguably, this does not demonstrate that the performance of the units selected by EPA to set the standard cannot be achieved by new units similar to the units that exceeded it in the dataset considered by EPA and, indeed, beyond that dataset. But EPA never evaluated that issue. To evaluate this issue, EPA would have had to consider the following sets of questions:

[261] *Id.* at 17-18.

1. Why did some of the aeroderivative units within the models upon which the standard is based fail to meet the emissions rate standard selected by EPA? And perhaps more importantly, what would similar new units have to do to meet the standard, and could they meet it? Are these actions properly required under NSPS?

2. Why did other aeroderivative models fail to meet the standard? Is the selected standard achievable by these other aeroderivative models?

3. Why did the F-Class units in the dataset fail to meet the standard? What would new units similar to those F-Class turbine models the dataset considered and that clearly emitted at a significantly higher rate than 1,170 lb CO_2/MWh have to do to meet the standard? Is that achievable?

4. Is the selected standard achievable for E-Class, H-Class, and J-Class turbines?

EPA's failure in the Carbon Pollution Standards to fully evaluate these questions is a fatal flaw in the Agency's analysis.

As the C&H Report explains, the three aeroderivative models upon which EPA based the standard for simple-cycle combustion turbines are not representative even of the universe of aeroderivative units currently available and used in the United States, much less the frame turbines that are or may be used. Moreover, the aeroderivative design is substantially different from the design of frame combustion turbines, so aeroderivative unit performance is not representative of the performance of the frame units.[262]

b. As a theoretical matter, assuming BSER can or should be based on operational constraints, the standard for simple-cycle units operating at intermediate load (and base load), should be significantly higher than the current standard.

The current Phase 1 standards for simple-cycle combustion turbines operating at intermediate load are expressed in terms of lb CO_2/MWh. Because there is a direct relationship between the CO_2 amount emitted and the amount of fuel combusted for any given fuel (here, natural gas), the standard boils down to a measure of the overall efficiency of the combustion turbine over the averaging period (here, 12 months). In setting a standard based on efficiency, therefore, EPA must account for, or at

[262] *See id.* at 20-24.

least understand, what factors affect a unit's efficiency. For combustion turbines, the starting point is the inherent efficiency of the turbine, which is determined by the design of the turbine. Typically, turbine manufacturers provide a guaranteed efficiency (often expressed in terms of heat rate in the electric generating industry) for each turbine model, under International Organization for Standardization ("ISO") conditions, at full load. The **actual**, real-world efficiency (expressed as the heat rate) of a combustion turbine – and, therefore, its CO_2 emission rate – depends on both the specification efficiency of the turbine and a myriad of operational and ambient conditions that can differ significantly from ISO conditions. As the C&H Report explains, "[a]t any given point in time, … the thermal efficiency of [a simple-cycle combustion turbine] is affected by a multitude of factors, among them: (1) the operating load; (2) degradation (both unrecoverable and between maintenance cycles); (3) altitude; (4) ambient temperature; [(5) inlet/outlet losses;] and ([6]) design margin."[263] The C&H Report provides the following estimates for the impact of these factors on the original equipment manufacturer specification heat rate of simple-cycle combustion turbines to approximate a "real-world" heat rate.

[263] *Id.* at 4. The CO_2 rate also is affected by the CO_2 content of the fuel. The C&H Report addressed with specificity only natural gas as a fuel. The same concepts apply to combustion turbines fueled by other fuels, such as diesel oil.

Table 1. Simple Cycle "Real World" Heat Rate Impacts
(C&H Report, Table 2-1)

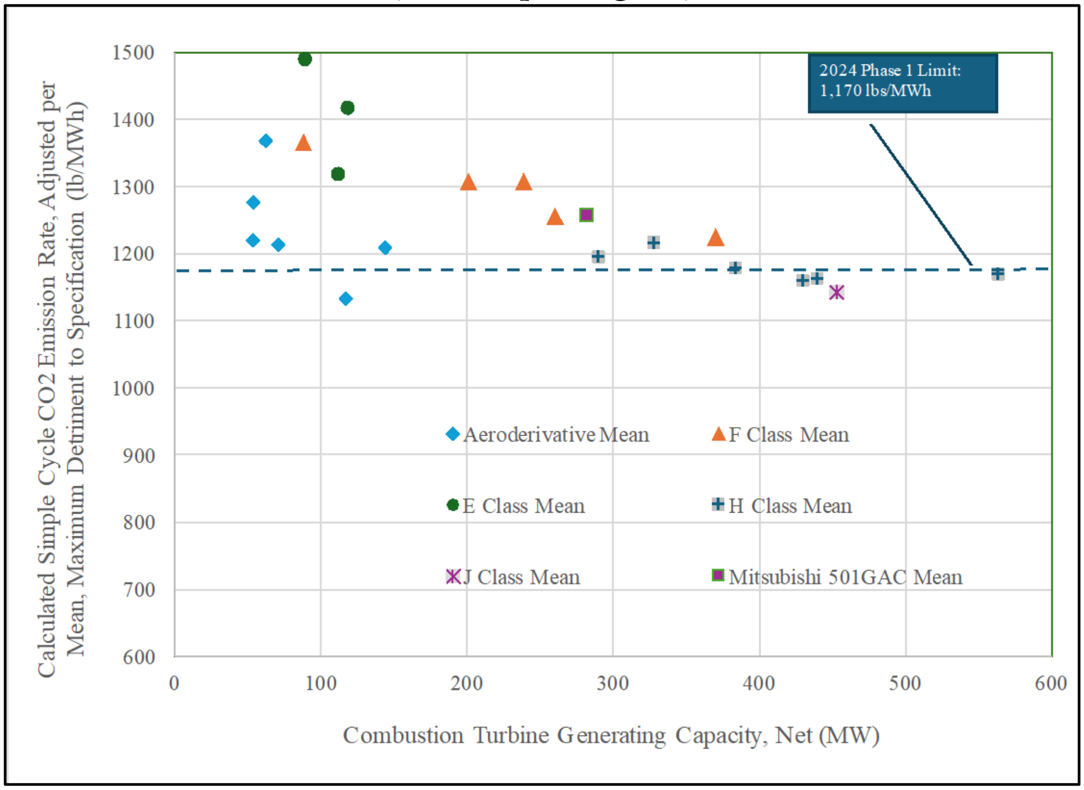
Factor	Heat Rate Impact	Mean Impact	Maximum Impact
Operating Load (fraction of capacity)	4% increase in heat rate at 80% load	3.5%	8%
Degradation	2-6% loss in 24,000 hrs; restorable to within 1-1.5% of design	4%	6%
Altitude[264]	3.5% loss in power = each 1,000 ft above sea level		
Ambient temperature	0.1% increase in heat rate = each 1° F above ISO	0.5%	1.6%
Inlet/Outlet losses per incurred air or gas pressure drop	0.2% increase in heat rate with each 1 inch w.g. increase in inlet/output pressure drop	0.8%	1.6%
CO_2 Compliance Margin	3-5%	4%	5%
Total		12.8%	22.2%

Based on the above estimates, the expected, **theoretical** CO_2 emissions rates, based on the mean[265] adjustment factors in Table 1, for various combustion turbine models currently available are as follows:

[264] Altitude results in a loss of maximum power output for a simple cycle combustion turbine, as reported above. It is unclear whether altitude also affects heat rate. This evaluation assumes no impact on heat rate from altitude.

[265] The figure above presents the results based on the mean "real-world" adjustments. An NSPS arguably should be based on the worst case – i.e., maximum – adjustments.

Figure 2. Calculated CO_2 Emission Rate: Simple Cycle (C&H Report Fig. 2-1)



The above figure shows that, even if the **mean** "real-world" adjustments were applied to turbine efficiency, most combustion turbines currently on the market would be unable to meet the natural-gas standard of 1,170 lb CO_2/MWh. Specifically, only a minority of aeroderivative models and the largest H-Class and J-Class units can meet the standard, assuming mean real-world conditions. Most aeroderivative models, as well as E-Class, F-Class, and H-Class (smaller than about 400 MW) models cannot meet the standard, assuming mean real-world conditions.

Based on Figure 2, the standards for non-low-load simple-cycle combustion turbines would have to be at least 1,350 lb CO_2/MWh for units larger than 200 MW (roughly, about 2,000 MMBtu/h base load rating), and no less than 1,500 lb CO_2/MWh for smaller simple-cycle combustion turbines (less than 2,000 MMBtu/h base load rating). As argued in Section III.A. above, however, PGen strongly urges EPA not to set an output-based standard, as even the "real world" data the Agency could use to set such a standard quickly become obsolete and irrelevant in today's rapidly changing power markets.

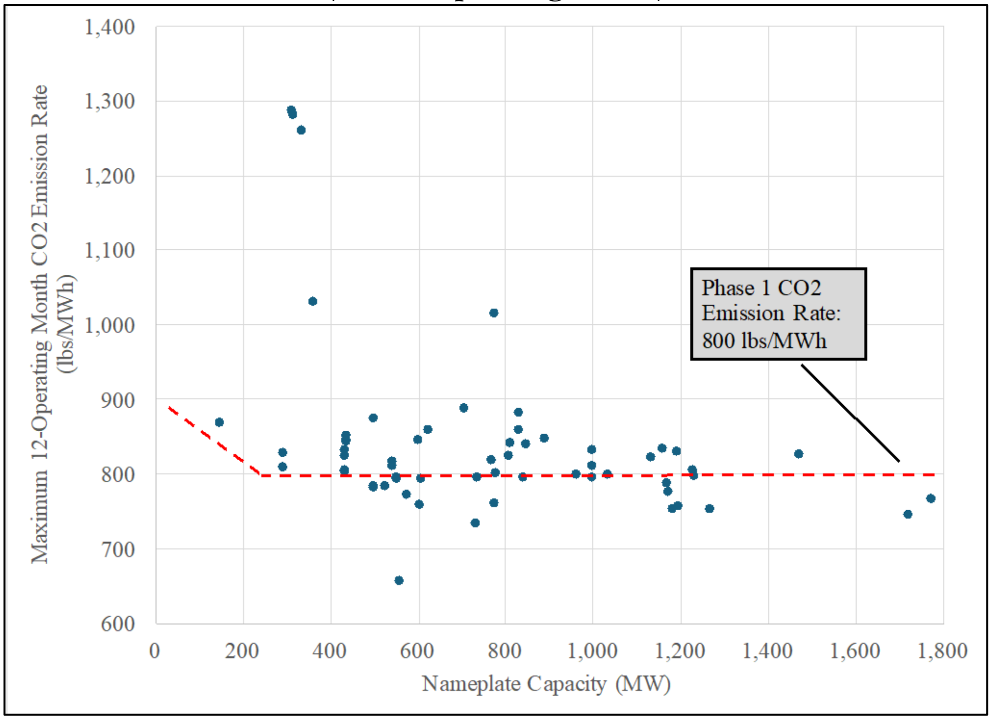
2. The Current Base Load Standards Are Deeply Flawed Because They Are Unachievable by a Number of Highly Efficient Turbines on the Market.

The current Phase 1 standards for natural gas-fired, combined-cycle power plants operating at a 12-month capacity factor of more than 40 percent suffer from the same flaws as the intermediate load standards. The base load Phase 1 standard is 800 lb CO_2/MWh for combustion turbine units with base load ratings greater than 2,000 MMBtu/h, and it increases (on a sliding scale) for smaller units to 900 lb CO_2/MWh for units with base loading rates of 250 MMBtu/h.

a. EPA based the standard for combustion turbines operating at base load on the performance of a single combined-cycle unit that is not representative of the variety of highly efficient units available on the market.

EPA's dataset for units operating at base load consisted of 59 units. The C&H Report complemented this dataset with an additional 10 units. The performance of these units is depicted in Figure 3.

Figure 3 – CO_2 Emissions Rate vs. Nameplate Capacity: Combined Cycle Units (C&H Report Figure 3-4)

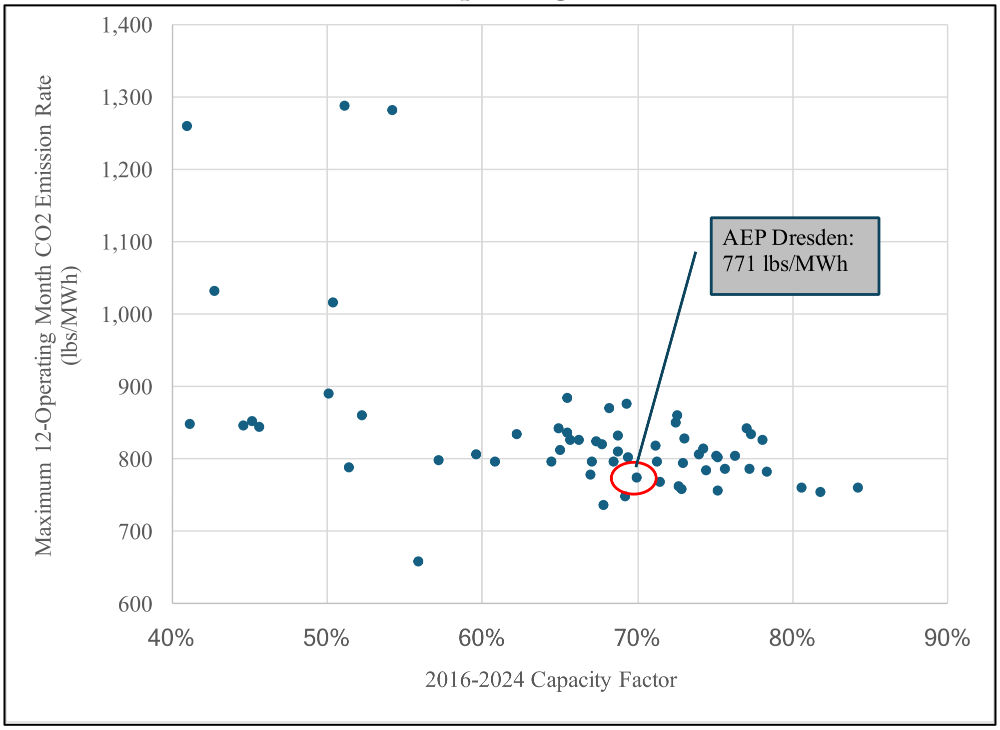


As an initial matter, all of the units in EPA's dataset were combined-cycle units, which are significantly more efficient than simple-cycle units. Any standard based on combined-cycle performance necessarily is unachievable by simple-cycle turbines. Indeed, EPA explicitly selected the 40 percent capacity demarcation between the base load and intermediate subcategories based on comparative analysis of the performance of simple cycle and combined cycle turbines. As discussed in more detail in Part III.B.3. below, EPA should abandon subcategorization based on capacity factor and instead subcategorize based on cycle – i.e., simple cycle versus combined cycle. This section of the comments addresses the standard that EPA should consider for a subcategory of combined cycle units operating at more than 20 percent capacity factor (or the subcategory now denoted as base load units, if EPA keeps this subcategory).

As is evident from Figure 3, EPA selected a standard that a majority of the operating combined-cycle units cannot – or at least, did not – meet. EPA's rationale for determining the specific numeric standard (i.e., 800 lb CO_2/MWh for units with a base load rating greater than 2,000

MMbtu/h) is hard to follow, as described in the C&H Report.[266] What is clear, however, is that the standard was largely based on the performance of the Dresden power plant unit in Ohio. Figure 4, below, depicts the same data as Figure 3 (but with 12-month capacity factor on the x-axis), and also identifies the Dresden unit.

Figure 4 – CO_2 Emissions from the Combined Cycle Population: Role of Dresden (C&H Report Figure 4-4)



Here too, however, as was the case for simple-cycle turbines, EPA did not consider, let alone evaluate, whether new units similar to those that emitted CO_2 at more than the selected standard could meet it, and what they would need to do to meet it. These other new units are not the same as the Dresden unit. They include different turbine models; they may operate differently (e.g., at a lower capacity factor and/or lower average operating factor); they may experience more startup and shutdown or load change cycles; or they may operate under less favorable ambient conditions (e.g.,

[266] C&H Report at 24-27.

elevation, average ambient temperature, etc.[267]). In other words, because the BSER for combustion turbines is efficiency, not a post-combustion control technology that can be dialed up or down, the performance of the units in the dataset that EPA considered may have emitted at higher than Dresden's rate because they operated "under [more] adverse conditions [that are] expected to recur."[268]

Indeed, EPA did not even analyze whether the Dresden unit itself would be able to meet the 800 lb CO_2/MWh standard, had the unit been located at a higher elevation, or operated in a location with higher ambient temperatures, or had it been called upon to operate at lower operating factors. In other words, EPA failed to analyze whether even the unit upon which EPA based its standard would be able to meet it if it was operated under more adverse conditions.[269]

In short, EPA's analysis of the 12-month rolling CO_2 emissions performance of the existing population of combined-cycle EGUs did not analyze whether any of these units would be able to meet the standard that EPA set on the basis of how Dresden happened to operate. These units could have emitted more than the standard because they are a different model of combustion turbines with a slightly less efficient – though still highly-efficient – design compared to the Dresden unit, and/or they could have operated under different conditions than Dresden. Without such an analysis, EPA has not considered whether new combined-cycle combustion turbines operate "under [more] adverse conditions that are expected to recur," as the law requires.[270]

---

[267] *See* Table 1 above.

[268] *See Nat'l Lime Ass'n*, 627 F.2d at 431 n.46, 433.

[269] *See id.*

[270] *Id.*

b. **As a theoretical matter, assuming BSER can or should be based on operational constraints, the standard for combined-cycle units operating at base load, should be significantly higher than the current standard.**

The current Phase 1 standards for combustion turbines operating at base load are expressed in terms of lb CO_2/MWh. Because there is a direct relationship between the CO_2 amount emitted and the amount of fuel combusted for any given fuel (e.g., natural gas, oil), the standard boils down to a measure of the overall efficiency of the combustion turbine over the averaging period (here, 12 months). In setting a standard based on efficiency, therefore, EPA must account for, or at least understand, what factors affect a unit's efficiency. For combined-cycle combustion turbines, the starting point is the inherent efficiency of the turbine, which is determined by the design of the turbine itself and the configuration of the unit (*e,g.*, 1x1 or 2x1 configuration). Typically, turbine manufacturers provide a guaranteed efficiency (often expressed also in terms of heat rate in the electric generating industry) for each turbine model in a specific configuration, under ISO conditions, at full load. For example, a GE 7F.04, in a 1x1 configuration has a **specification**[271] heat rate of 5,716 Btu/KWh, LHV.[272] The **actual** efficiency (expressed as heat rate) of a combined-cycle combustion turbine is the result, however, of the inherent/design efficiency of the unit, and the impact of various factors on that efficiency. As the C&H Report explains, "[a]t any given point in time, . . . the thermal efficiency of [a combined-cycle combustion turbine] is affected by a multitude of factors, among them: (1) the operating load; (2) degradation (both unrecoverable and between maintenance cycles); (3) altitude; (4) ambient temperature; [(5) air inlet fouling; (6) condenser conditions] and ([7]) design margin."[273] The

---

[271] A specification is essentially a benchmark or requirement set for the equipment before it is built or installed.

[272] *See, e.g.*, GE Vernova, GE Vernova 7F gas turbine, https://www.gevernova.com/gas-power/products/gas-turbines/7f.

[273] C&H Report at 4.

C&H Report provides the following estimates for the impact of these factors on the specification heat rate of combined-cycle combustion turbines to approximate a "real-world" heat rate.

Table 2. Combined Cycle "Real World" Heat Rate Impacts (C&H Report, Table 2-2)

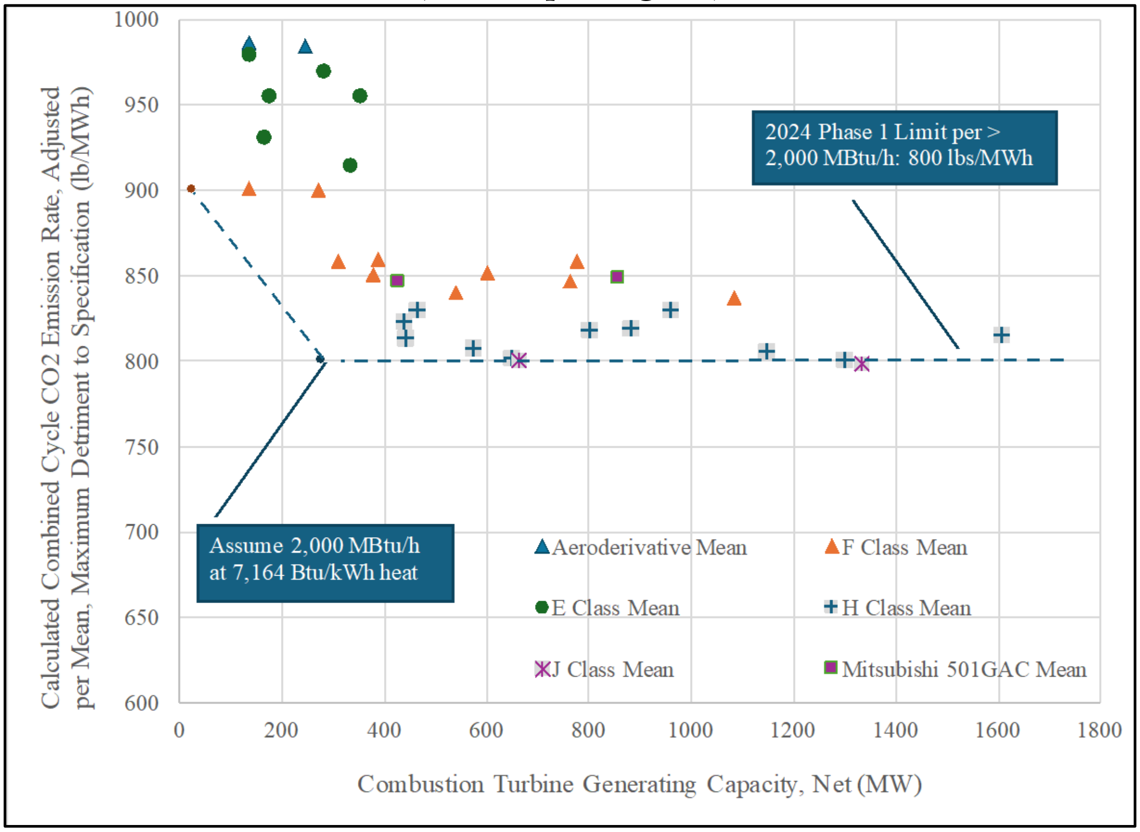
Factor	Impact	Mean Impact	Maximum Impact
Operating Load (fraction of capacity)	4% increase in heat rate per cycling, frequent startup/shutdown.	4%	6%
Degradation	3-5% loss in 10-15 Years	4%	5%
Altitude	0.2% increase in heat rate = each 1,000 ft above sea level	0%	1.2%
Ambient temperature	0.5% higher heat rate = per 10˚ F above ISO	0.25%	0.8%
Air Inlet Fouling	1.2% increase in heat rate, not recoverable	1.2%	1.8%
Condenser (Heat Removal)	1% increase in heat rate per 0.5-inch Hg absolute pressure[274]	2% (per 1.0 in Hg	4% (per 2 in Hg
Design Margin	3-5%	4%	5%
Total		15.5%	23.8%

Based on the above estimates, the expected, **theoretical** CO_2 emissions rates, based on the mean[275] adjustment factors in Table 2, for various new combustion turbine models currently available are as follows:

[274] Table 1 describes "new and clean" as 1.2 in Hg absolute; means and maximum impact values assumed as 1 and 2 in Hg absolute, respectively.

[275] The figure above presents the results based on the mean "real-world" adjustments. An NSPS arguably should be based on the worst case – i.e., maximum – adjustments.

Figure 5. Calculated CO_2 Emission Rate: Combined Cycle (C&H Report Fig. 2-2)



The above figure shows that, even if the **mean** "real-world" adjustments were applied, virtually all combined-cycle combustion turbines currently on the market would be unable to meet the natural gas standard of 800-900 lb CO_2/MWh (depending on base load rating). Specifically, only a minority of H-Class and J-Class units can meet the standard, assuming mean "real-world" conditions. All other models would be unable to meet the current standard.

Based on Figure 5, the standards for non-low-load combined-cycle combustion turbines would have to be at least 900 lb CO_2/MWh for units larger than 400 MW (roughly, about 2,500 MMBtu/h base load rating), and no less than 1,000 lb CO_2/MWh for smaller combined-cycle combustion turbines (less than 2,500 MMBtu/h base load rating). As argued in Section III.A. above, however, PGen strongly urges EPA not to set an output-based standard, as even the "real world" data it could use to set such a standard quickly become obsolete and irrelevant in today's rapidly changing power markets.

3. EPA's Selection of an Annual Capacity Factor of 40 percent as the Dividing Threshold Between Simple-Cycle Combustion Turbines and Combined-Cycle Combustion Turbines Should Be Eliminated or Revised Upwards.

a. Combustion turbines operating at more than a 12-month average capacity factor of 20 percent should be subcategorized based on their mode of operation (i.e., simple cycle and combined cycle), not on the basis of their utilization.

The CPS Rule subcategorized combustion turbines operating at more than a 20 percent average annual capacity factor as intermediate load (units operating at capacity factors of 20 percent to 40 percent) and base load units (units operating above 40 percent capacity factor), and EPA based the standards for these categories on the performance of simple-cycle and combined-cycle units, respectively. In essence, therefore, EPA's CPS Rule prohibits a simple-cycle unit from operating at more than a 40 percent capacity factor. As discussed in more detail below, EPA based this 40 percent threshold on a calculated levelized cost of electricity ("LCOE") for the two types of turbines, concluding, effectively, that it is universally cost-effective to require all units that may operate at more than a 40 percent capacity factor to be combined-cycle units. As an initial matter, EPA's authority to require an operator to construct a different type of unit than the unit the operator proposes is questionable. This is akin to redefining the source, here, from a proposed simple-cycle turbine to a combined-cycle turbine. This is likely unlawful or, at a minimum, bad policy.

Electric generators are rational actors; in fact, their entire model of operation rests on the fundamental concept of economic dispatch – i.e., dispatching units with a lower cost of production ahead of those with a higher cost of production. If an operator proposes to construct a simple-cycle turbine and to run it at more than a 40 percent capacity factor (say, 42 percent, or 45 percent, or more) at a particular plant, it is necessarily because that operator has determined that it is more economically rational to do so in that particular situation – i.e., likely because the LCOE for the proposed simple-cycle unit is lower than that of a combined-cycle at the same location.

Moreover, what EPA's LCOE-based analysis does not account for is the cost of prohibiting the use of a simple-cycle turbine at more than 40 percent under some circumstances. Take a simple-cycle combustion turbine that is constructed in 2025, on the expectation the unit would generally run slightly less than a 40 percent capacity factor. Indeed, the unit runs as expected – at less than a 40 percent capacity factor – in 2026 and 2027. In 2028, however, an unusually hot summer or cold winter, or some other unusual circumstance (say, the local nuclear plant becomes unavailable during high demand season; or a large unit in the area experiences a major, forced shutdown) requires the use of the existing simple-cycle to meet demand during that period, such that the 12-month rolling capacity factor of the unit would likely exceed 40 percent. Failure to run the unit could result in electric service interruption or in destabilizing the grid. In such a circumstance, the cost of prohibiting this simple-cycle unit from running to meet demand is extremely high, and it is entirely irrelevant that its LCOE would be higher than that of a non-existent combined-cycle unit.

It is simply not for EPA to mandate what type of unit should be used in what circumstance. The rational solution to this problem is for EPA to subcategorize combustion turbines (that are not operating at low load) on the basis of their configuration, not capacity factor. Under such an approach, any simple-cycle unit operating at above a 20 percent capacity factor must meet the standard for simple-cycle units, even if it operates at more than a 40 percent capacity factor; and any combined-cycle unit operating at above a 20 percent capacity factor must meet the standard for combined-cycle units, even if it operates at less than a 40 percent capacity factor.[276] Such a subcategorization is highly

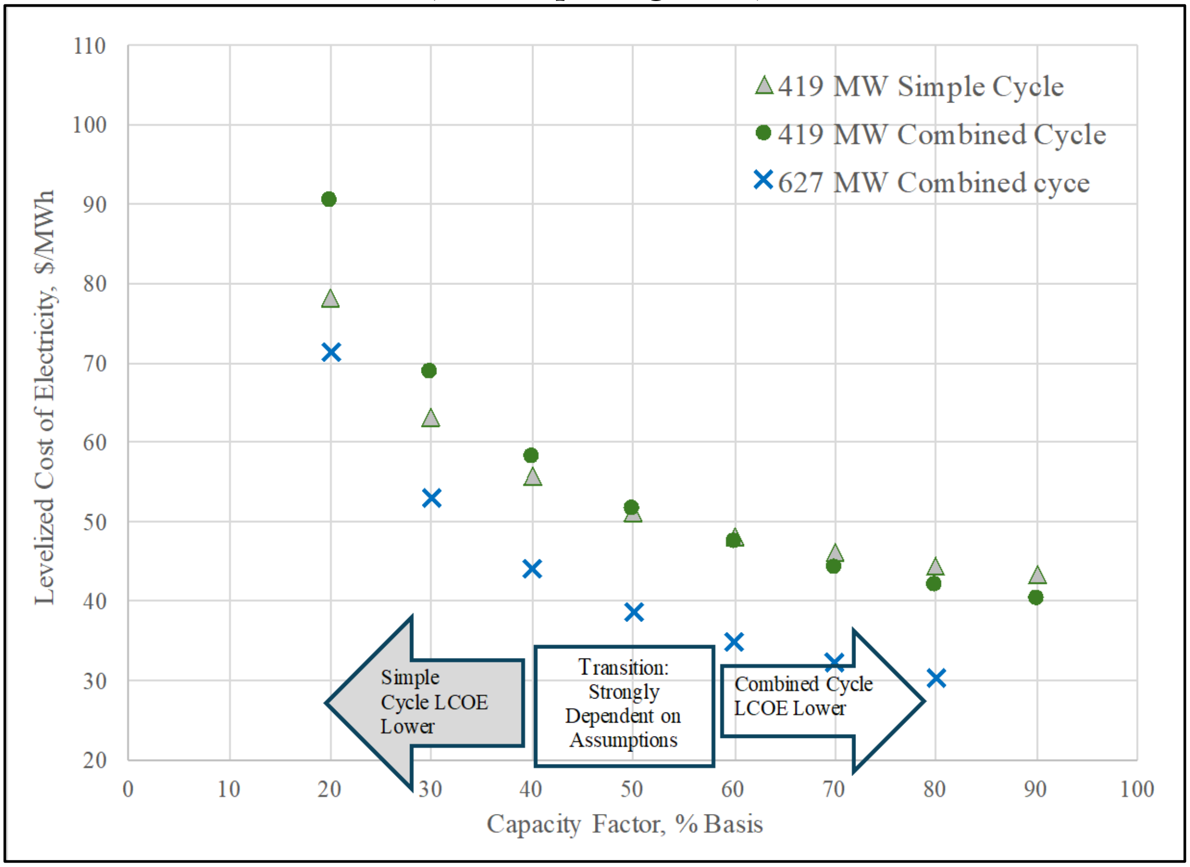
[276] EPA should also address how the standards would apply to a combined-cycle combustion turbine that sometimes may operate in single-cycle mode. A weighted average scheme, similar to situations under the current rules when different fuels are used at a single unit, would likely address the situation.

unlikely to lead to a major shift in how electric generators procure or operate combustion turbines. After all, because operating costs for simple-cycle combustion turbines are generally higher than operating costs for combined-cycle combustion turbines, economic dispatch of generation fleets has generally resulted in electric generators operating simple-cycle turbines at lower capacity factors and combined-cycle units at higher capacity factors for decades, without a CO_2 NSPS mandating it. Those decisions have been dictated by the type of duty needed as well as economics. If those factors do not change in the future, electric generators will keep doing what they've done in the past; it would be economically irrational for them to do otherwise. And if these conditions change in the future, and operators start using simple-cycle units at capacity factors exceeding 40 percent, it will be **because** the economics or other operational needs have changed so as to demand such operations. No one, including EPA, can possibly predict whether the economics and needs for simple-cycle versus combined-cycle combustion turbines operating at higher than a 40 percent capacity factor will change in the next decades (much less indefinitely), and how. For these reasons, PGen urges EPA to reconsider the subcategories for intermediate load and base load and replace them with standards based on the configuration of the turbines – simple-cycle and combined-cycle.

b. If EPA retains the current intermediate load and base load subcategories, it should increase the demarcation between the two subcategories to an annual capacity factor of 60 percent.

To be clear, for all the reasons discussed above, PGen does **not** want EPA to retain the capacity factor-based subcategories. That being said, if EPA nonetheless retains this method of subcategorization, then the threshold for what constitutes a base load unit needs to be increased to an annual capacity factor of at least 50 to 60 percent. EPA's cost-effectiveness analysis underlying EPA's selection of 40 percent depends on multiple extrapolations and is not nearly as robust as such an analysis requires. As the C&H Report explains, EPA's multiple extrapolations to compare the LCOE of two equally sized simple-cycle and combined-cycle combustion turbines introduce substantial, compounding error and uncertainty.[277] Using a more straightforward methodology based on data in a 2024 EIA study and involving a single extrapolation, the C&H Report results in a LCOE break-even point of about 52 percent capacity factor, instead of EPA's 40 percent.[278] Those results are illustrated in Figure 6.

Figure 6. LCOE Equivalent per Adjusted EIA Analysis (C&H Report Figure 5-1)



To be sure, the C&H evaluation uses different parameters than EPA's: a 25-year life (instead of 30 years used by EPA); $4/MBtu (instead of $4.42/MBtu used by EPA) for the future cost of gas; and a 0.5 (instead of EPA's 0.6) scaling exponent. The first two are at least as reasonable as EPA's assumptions, perhaps even more so (for example, the $4/MBtu cost of gas is much closer to EIA's

[277] C&H Report at 28-31.

[278] *Id.* at 32.

estimate for future costs than EPA's is). The scaling exponent of 0.5 is more appropriate than EPA's, though still quite conservative.[279] Regardless, the differences in these parameters is very small, yet the impact on the LCOE comparison is large. EPA's parameters yield a LCOE break-even point of a little more than a 40 percent (about 42 percent) capacity factor; and the parameters used in the C&H Report (which are at least as reasonable as EPA's) result in a LCOE break-even point of about a 52 percent capacity factor. Given the high sensitivity of the results to these changes, and the substantial uncertainty in what these parameters will be in the future (especially the cost of gas), it is arbitrary and capricious for EPA to select 40 percent as the cutoff between the intermediate load (i.e., simple-cycle) subcategory and the base load (i.e., combined-cycle category). Indeed, given these results and their sensitivity to assumed inputs, EPA should adopt 60 percent as the threshold for the base load subcategory.[280]

IV. EPA's Primary Proposal

As noted earlier, PGen believes that the Alternative Proposal provides the immediate relief the industry needs, and independent of whether the Primary Proposal is ultimately finalized, EPA should proceed to finalize the Alternative Proposal promptly—particularly given the clear technical record concerning the unavailability of CCS. PGen offers the following comments on the Primary Proposal for EPA's consideration in the event it decides to finalize the Primary Proposal, perhaps after it finalizes the Alternative Proposal.

---

[279] *Id.* at 33.

[280] If the LCOE analysis were to be repeated with the price of gas at $3.50/MBtu instead of $4.00/MBtu, the equivalence points shift to 60 percent.

A. Before EPA Can List a New Source Category Under Section 111, It Must Find that the Source Category Significantly Contributes to Endangering Air Pollution (C-2, C-8).

In the Proposed Repeal Rule, "EPA proposes to conclude that, at a minimum, the Administrator must make a significant contribution finding before issuing GHG emission standards for a new source category even if covered sources had previously been listed under a distinct category."[281] EPA's proposed conclusion is the appropriate and lawful reading under the CAA. Section 111 requires EPA to list a category of stationary sources if, in the Administrator's judgment, the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[282] EPA has historically referred to this determination as an "endangerment finding" and has noted that the "phrase encompasses both the 'causes or contributes significantly' component and the 'endanger public health and welfare' component of the determination."[283]

Thus, a new source category listing requires an affirmative finding by EPA that emissions of the pollutant targeted for regulation from the source category significantly contribute to endangering air pollution. In 2015, when EPA first promulgated the NSPS in Subpart TTTT to address CO_2 emissions from new, modified, and reconstructed fossil fuel-fired EGUs, the Agency took the position that "because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to affected EGUs in order to establish standards of performance for the CO_2 emissions from these sources."[284] This position was challenged by 25 states, labor unions, and numerous industry parties and was included in briefing before the U.S. Court of

[281] 90 Fed. Reg. at 25,755.

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

[283] 80 Fed. Reg. at 64,529.

[284] *Id.*

Appeals for the District of Columbia Circuit.[285] The litigation challenging this position remains before the D.C. Circuit, where it is in abeyance.[286]

In its 2015 rule promulgating Subpart TTTT, EPA claimed it need not make a new endangerment finding for fossil fuel-fired EGUs because it was not listing a brand-new source category.[287] Instead, EPA erroneously argued that findings it made in 1971 and 1977 regarding emissions of other pollutants (not CO_2) from "steam generators"[288] and "stationary gas turbines"[289] fulfilled the Agency's obligation under section 111(b)(1)(A) to make an endangerment finding before listing a new source category.[290] EPA was wrong to claim in 2015 that it was not listing a new source category. It was. Its prior findings related to steam generators (for which EPA established NSPS under Subpart Da) and stationary combustion turbines (for which EPA established NSPS under Subpart KKKK). In the 2015 rule, EPA established an entirely new category—codified in a new Subpart TTTT of its regulations—which it said was "specifically created for CAA 111(b) standards of performance for GHG emissions from fossil fuel-fired EGUs."[291] Subpart Da and Subpart KKKK remained the same and were unaffected, further demonstrating that Subpart TTTT was a new listing by EPA of a source category, which required an affirmative finding by EPA that emissions of the pollutant targeted

---

285 *See* Opening Brief of Non-State Petitioners at 63-64, ECF No. 1659209, *North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. Feb. 3, 2017); State Petitioners' Final Opening Brief at 34-35, ECF No. 1659341, *North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. Feb. 3, 2017).

286 Order, ECF No. 1688176, *North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. Aug. 10, 2017).

287 80 Fed. Reg. at 64,529.

288 Air Pollution Prevention and Control, 36 Fed. Reg. 5931 (Mar. 31, 1971) (one-sentence endangerment finding).

289 Air Pollution Prevention and Control, 42 Fed. Reg. 53,657 (Oct. 3, 1977).

290 80 Fed. Reg. at 64,527, 64,529-30.

291 *Id.* at 64,512.

for regulation—here, GHGs and/or CO_2—from the source category—here, fossil fuel-fired EGUs—significantly contribute to endangering air pollution. EPA unlawfully did not make this finding when it listed fossil fuel-fired EGUs as a source category.

Moreover, even if EPA could combine two previously listed source categories and rely on the endangerment findings made at the time those source categories were listed, EPA's prior listing of steam generators and stationary gas turbines covered only emissions of NOx, SO_2, and particulate matter. As discussed further in Section IV.B, before a pollutant may be regulated from an already listed source category, EPA must find that emissions of that new pollutant from the already listed source category significantly contribute to endangering air pollution. Because EPA's findings in the 1971 and 1977 listings for steam generators and stationary gas turbines addressed **different** pollutants, those listings triggered and authorized regulation only of those pollutants.[292]

In sum, section 111(b)(1)(A) required EPA to make a finding before listing the new fossil fuel-fired EGU source category that GHG emissions from that new source category significantly contribute to endangering air pollution. EPA unlawfully did not make that finding when it listed the source category in 2015. Whether EPA could or should make this finding is a separate inquiry. Rather, PGen is saying that the CAA requires EPA to make such a finding before it may list a new source category, and EPA did not do so in 2015. Earlier findings of endangerment and significant contribution made for emissions of other pollutants from other source categories do not suffice.

[292] *Cf. Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 783 (D.C. Cir. 1976) (noting section 111(b)(1) of the CAA "obviously contemplates an evaluation by the Administrator of the risk that certain types of air pollution will 'endanger' public health and welfare").

B. Before EPA Can Regulate a Pollutant from a Listed Source Category, It Must Find that Emissions of the Pollutant from the Source Category Significantly Contribute to Endangering Air Pollution (C-1, C-5, C-8, C-9).

In the Proposed Repeal Rule, EPA "proposes to conclude that Congress required the EPA to identify more than a rational basis for regulating emissions from a source category."[293] PGen agrees with and supports EPA's proposed conclusion. EPA has previously interpreted section 111(b)(1)(B) to provide EPA with authority to "set a standard for an additional pollutant for a source category that was previously listed and regulated for other pollutants . . . as long as the EPA has a **rational basis** for setting a standard for the pollutant."[294] EPA's previous interpretation cannot possibly be considered the "best reading" of section 111,[295] and it has been challenged in numerous cases, including the litigation involving EPA's 2015 promulgation of Subpart TTTT, that are currently in abeyance before the D.C. Circuit.[296]

In the case of the NSPS addressing GHG emissions from the fossil fuel-fired EGU source category, the endangerment and significant contribution findings on which all of the NSPS rests were

---

[293] 90 Fed. Reg. at 25,763.

[294] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35,824, 35,842 (June 3, 2016) (emphasis added) (final EPA rule promulgating NSPS to address methane emissions from the Oil and Natural Gas Production source category).

[295] *Loper Bright Enters. v. Raimondo*, 603 U.S. 369, 395-96 (2024).

[296] *See* State Petitioners' Final Opening Brief at 34-37, ECF No. 1659341, *North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. Feb. 3, 2017) (challenge to Subpart TTTT); Opening Brief of Non-State Petitioners at 63-66, ECF No. 1659209, *North Dakota v. EPA*, No. 15-1381 (D.C. Cir. Feb. 3, 2017) (challenge to Subpart TTTT); *see also, e.g.*, Nonbinding Statement of Issues of West Virginia, *et al.*, ECF No. 1634136, *North Dakota v. EPA*, No. 16-1242 (and consolidated cases) (D.C. Cir. Sept. 7, 2016) (identifying as issues in the case (i) whether EPA's NSPS to address methane emissions from the Oil and Natural Gas Production source category is unlawful because EPA failed to make endangerment and significant contribution findings with respect to methane emissions from the source category and (ii) whether the NSPS is unlawful because EPA concluded it needed only a "rational basis" before regulating methane from the source category); Nonbinding Statement of Issues of the American Petroleum Institute at 2, ECF No. 1634081, *North Dakota v. EPA*, No. 16-1242 (and consolidated cases) (D.C. Cir. Sept. 6, 2016) (identifying as an issue whether EPA's methane NSPS for the oil and gas sector is unlawful because EPA asserted it did not need to make a pollution-specific

made **a half century ago** (in 1971 and 1977) and addressed **different pollutants** (NOx, SO_2, and particulate matter) from **two different source categories** (steam generators and stationary combustion turbines). These different findings do not give EPA a regulatory blank check **for all time** to regulate any other air pollutant from the source category. Indeed, this interpretation has no limiting principle: EPA could regulate any air pollutant from any listed source category, regardless of whether the specific pollutant endangers public health or welfare, and regardless of whether the source category is a significant contributor to that endangering air pollution. Congress never intended to give EPA that kind of power under the CAA.

EPA conceded in the 2015 NSPS rule promulgating Subpart TTTT that other endangerment provisions in the CAA besides section 111 "do require the EPA to make endangerment findings for each particular pollutant that the EPA regulates under those provisions."[297] EPA was wrong, however, when it claimed that the wording of section 111(b) somehow leads to a different result. Section 111(b)(1)(B) provides that EPA may issue performance standards for sources listed under section 111(b)(1)(A).[298] A "standard of performance" is, by definition, tied to the specific pollutants for which an endangerment finding has been made.[299] Any other reading would give EPA unfettered authority to regulate any air pollutant emitted by that source regardless of whether it endangers health or welfare, which the Supreme Court disavowed.[300]

---

endangerment and significant contribution finding for the Oil and Natural Gas Production Source Category).

[297] 80 Fed. Reg. at 64,530 (citing CAA §§ 202(a)(1), 211(c)(1), 231(a)(2)(A), 42 U.S.C. §§ 7521(a)(1), 7545(c)(1), 7571(a)(2)(A)).

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

[299] *See id.* § 111(a)(1), 42 U.S.C. § 7411(a)(1) (defining a "standard of performance" as "a standard for emissions of **air pollutants**") (emphasis added).

[300] *See Massachusetts v. EPA*, 549 U.S. 497, 532-33 (2007) (holding that EPA does not have "a roving license to ignore the statutory text"); *see generally id.* at 532-35.

Legislative history confirms that Congress viewed the endangerment sections in the CAA as "standardized" provisions and that "[t]his same basic formula is used" throughout the Act.[301] Indeed, in 2009, EPA observed that the CAA contains several endangerment provisions sharing a basic architecture: "In all of the various provisions, there is broad similarity in the phrasing of the endangerment and contribution decision."[302] The only difference EPA noted then was that section 111(b) creates a **higher** standard by requiring a finding of "'**significant**' contribution."[303] This higher standard means more—not less—evidence of contribution to endangerment is required.

Ultimately, even EPA did not really accept its own argument when it promulgated Subpart TTTT in 2015. In the final rule promulgating Subpart TTTT, the Agency invented an extra-textual "rational basis" standard to try to cabin its otherwise limitless theory.[304] But this invented "rational basis" standard is found nowhere in section 111, and that deferential standard is not what Congress enacted.

In sum, section 111(b)(1)(A) requires EPA to make a finding that emissions of a new air pollutant, even from a previously listed source category, significantly contribute to endangering air pollution before EPA can issue performance standards for that air pollutant. EPA unlawfully did not make that finding when it first promulgated NSPS in 2015 to address GHG emissions from fossil fuel-fired EGUs. Again, whether EPA could or should make this finding is a separate inquiry. The

[301] H.R. Rep. No. 95-294 at 50 (1977), *reprinted in* 4 COMM. PRINT, A LEGISLATIVE HISTORY OF THE CLEAN AIR ACT AMENDMENTS OF 1977 at 2517 (1978).

[302] Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,507 (Dec. 15, 2009).

[303] *Id.* at 66,506 (emphasis added).

[304] 80 Fed. Reg. at 64,530.

point is that the CAA requires EPA to make such a finding before promulgating NSPS to address pollutants from a listed source category, and EPA did not do so in 2015 or 2024.[305]

C. EPA's Attempts to Regulate GHG Emissions from Fossil Fuel-Fired EGUs Under Section 111 Over the Past Decade Demonstrate that It May Not Be Possible to Regulate GHGs from EGUs Under the NSPS Program.[306]

As part of the Primary Proposal, EPA proposes to find "that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution as required for the promulgation of new and existing source standards."[307] If EPA finalizes this proposed determination, the result would be the repeal of all of the performance standards addressing GHG emissions from fossil fuel-fired EGUs (*i.e.*, Subparts TTTT, TTTTa, and UUUUb).[308] Without opining on this part of the Proposed Repeal Rule, PGen notes that a separate basis may exist for EPA to find that regulation of GHGs from fossil fuel-fired EGUs cannot be done within the scope of section 111.

1. The Supreme Court's Decision in *Utility Air Regulatory Group v. EPA* Makes Clear that GHGs Should Be Regulated Under a Particular CAA Program Only When It Makes Sense Within that Program's Overall Regulatory Scheme.

The first regulation of GHG emissions under the CAA took place in 2010, when EPA issued GHG emissions standards for light-duty motor vehicles under section 202(a) of the Act.[309] The

---

[305] In the alternative, EPA claimed in the 2015 NSPS that its 2009 finding regarding GHG emissions from automobiles would fulfill this requirement. 80 Fed. Reg. at 64,530. Not so. EPA emphasized that the 2009 finding was made "for purposes of CAA section 202(a))." 74 Fed. Reg. at 66,499. Similarly, EPA's additional last-ditch attempt to manufacture a significant contribution finding by claiming "the information and conclusions" contained in the NSPS rule "should be considered to constitute the requisite endangerment finding" and "cause-or-contribute significantly findings," 80 Fed. Reg. at 64,530, does not suffice. EPA did not specify what "information and conclusions" it had in mind, and discussions of climate change generally do not meet the requirements of section 111.

[306] Not all PGen members join in this section of the comments.

[307] 90 Fed. Reg. at 25,755.

[308] *Id.*

[309] Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, 75 Fed. Reg. 25,324 (May 7, 2010).

emissions standards would begin with Model Year 2012, which meant that the standards would take effect on January 2, 2011 (the earliest date on which a Model Year 2012 vehicle could be introduced into commerce).[310] Once the emissions standards went into effect on January 2, 2011, GHGs would become "subject to regulation" under the CAA, which would trigger obligations for GHGs under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs.[311] The PSD program applies to any "major emitting facility" that undertakes construction or modification, and the CAA defines a "major emitting facility" as one that emits 100 or 250 tons per year of any pollutant that is "subject to regulation" under the Act.[312] The Title V program applies to "major sources," which are defined as any source that emits at least 100 tons per year of any pollutant that is "subject to regulation."[313]

The problem, however, was that applying the 100 and 250 ton per year thresholds to GHGs—particularly CO_2—would have brought "tens of thousands of small sources and modifications into the PSD program each year, and millions of small sources into the title V program."[314] EPA determined that applying the 100 and 250 ton per year thresholds of the PSD and Title V programs to GHG emissions would lead to an "extraordinary increase[] in the scope of the permitting programs

---

310 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514, 31,521 (June 3, 2010) (the "Tailoring Rule").

311 *Id.* at 31,521-22.

312 *See id.* at 31,528 (citing CAA §§ 165(a), 169(1) (definition of "major emitting facility"), 169(2)(C) (definition of "construction"), 42 U.S.C. §§ 7475(a), 7479(1), 7479(2)(C)); *see also* 40 C.F.R. §§ 52.21(b)(50)(iv), 52.21(b)(2) (limiting the term "any air pollutant" in the PSD provisions to those pollutants that are "subject to regulation under the Act").

313 *See* 75 Fed. Reg. at 31,528 (citing CAA §§ 302(j) (definition of "major stationary source" and "major emitting facility"), 501(2)(B) (definition of "major source"), 502(a), 42 U.S.C. §§ 7602(j), 7661(2)(B), 7661a(a); *see also* Memorandum from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards, U.S. EPA, "Definition of Regulated Air Pollutant for Purposes of Title V" (Apr. 26, 1993) (limiting the term "any air pollutant" in the Title V program only to those pollutants that are subject to regulation under the CAA)).

314 75 Fed. Reg. at 31,533.

[that] would mean that the programs would become several hundred-fold larger than what Congress appeared to contemplate."[315] This, in turn, would lead to numerous adverse consequences: (1) the addition of small sources to the PSD and Title V programs that Congress did not expect would be part of these programs and that "would face unduly high permitting costs"; (2) "multi-year backlogs in the issuance of PSD and title V permits"; (3) sources of all types facing construction delays while awaiting permits; and (4) many small sources needing to obtain a Title V permit for the first time would have "empty" permits that would not contain any applicable requirements.[316] EPA also found that "[f]or both programs, the addition of enormous numbers of additional sources would provide relatively little benefit," and in the case of the PSD program, "the large number of small sources that would be subject to control [would] constitute a relatively small part of the environmental problem."[317]

To resolve this problem, EPA issued the Tailoring Rule, which changed the thresholds for GHG emissions under the PSD and Title V permitting programs from 100 or 250 tons per year (depending on the type of source) to 75,000 or 100,000 tons per year of carbon dioxide equivalent ("CO_2e") (depending on the circumstance).[318] EPA used the "absurd results," "administrative necessity," and "one-step-at-a-time" doctrines to justify this change.[319]

The Tailoring Rule was challenged by numerous parties, and the Supreme Court ultimately heard the case and overturned the Tailoring Rule,

> reaffirm[ing] the core administrative-law principle that an agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate. EPA therefore lacked authority to "tailor" the Act's unambiguous numerical thresholds to accommodate its greenhouse-gas-inclusive interpretation of the permitting triggers. Instead, **the**

[315] *Id.*

[316] *Id.*

[317] *Id.*

[318] *Id.* at 31,516.

[319] *Id.* at 31,541-45.

> **need to rewrite clear provisions of the statute should have alerted EPA that it had taken a wrong interpretive turn**. [320]

Importantly, the Supreme Court made clear that even though it found previously in the case of *Massachusetts v. EPA*[321] that GHGs fall within the CAA's definition of "air pollutant," that definition "is not a command to regulate, but a description of the universe of substances EPA may **consider** regulating under the Act's operative provisions."[322] In *Utility Air Regulatory Group*, the Court emphasized that "*Massachusetts* does not strip EPA of authority to exclude greenhouse gases from the class of regulable air pollutants under other parts of the Act where their inclusion would be inconsistent with the statutory scheme."[323] Because the CAA's use of the term "air pollutant" can "denote less than the full range of pollutants covered by the Act-wide definition[,] . . . [i]t is therefore incumbent on EPA to specify the pollutants encompassed by that term in the context of a particular program, and to do so reasonably in light of that program's overall regulatory scheme."[324]

2. EPA's Numerous Attempts to Regulate GHG Emissions from Fossil Fuel-Fired EGUs Under Section 111

The ten-year history of EPA's attempts to regulate GHG emissions from fossil fuel-fired EGUs under section 111 shows that including GHGs in the NSPS program for these sources may be "inconsistent with the statutory scheme"[325] and the NSPS "program's overall regulatory scheme."[326]

---

[320] *UARG v. EPA*, 573 U.S. at 328 (emphasis added).

[321] *Massachusetts*, 549 U.S. at 532 ("Because greenhouse gases fit well within the Clean Air Act's capacious definition of 'air pollutant,' we hold that EPA has the statutory authority to regulate the emission of such gases from new motor vehicles.").

[322] *UARG v. EPA*, 573 U.S. at 319 (emphasis in original).

[323] *Id.*

[324] *Id.* at 328 n.8.

[325] *Id.* at 319.

[326] *Id.* at 328 n.8.

As a result, EPA could consider exercising its "authority to exclude greenhouse gases from the class of regulable air pollutants" under section 111 for fossil fuel-fired EGUs.[327]

EPA has repeatedly tried—and failed—to regulate GHG emissions from fossil fuel-fired EGUs under section 111. In 2015, EPA promulgated the Clean Power Plan, a rule that attempted to regulate GHG emissions from existing steam generating units and existing combustion turbines under section 111(d).[328] In determining the BSER for these EGUs, EPA identified heat rate improvements as a system of emission reduction for coal-fired steam generating units and found them to be "a low-cost option that fit the criteria for the BSER, except that they lead to only small emission reductions for the source category."[329] As a result, EPA determined that "the quantity of emissions reductions resulting from the application of these measures is too small for these measures to be the BSER by themselves for this source category."[330] Because EPA believed that "much larger emission reductions are needed from fossil fuel-fired EGUs to address climate change," it decided instead to rely on "generation shifting," whereby higher-emitting generation would be replaced by lower- or zero-emitting generation.[331] In addition to the heat rate improvements at coal-fired EGUs (which EPA called building block 1), the Clean Power Plan required a shift in electricity production from coal-fired steam generating units to gas-fired EGUs (building block 2), as well as a shift from both coal- and gas-fired EGUs to renewable generation, primarily wind and solar (building block 3).[332] The Clean Power Plan was stayed by the Supreme Court and never went into effect.[333]

---

[327] *Id.* at 319.

[328] 80 Fed. Reg. at 64,662.

[329] *Id.* at 64,727.

[330] *Id.*

[331] *Id.* at 64,728.

[332] *Id.* at 64,745-48.

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

Following a change in administration, the D.C. Circuit litigation challenging the Clean Power Plan was placed in abeyance while the new administration reconsidered it. EPA's second attempt at regulating GHG emissions from existing EGUs followed: the Affordable Clean Energy ("ACE") Rule.[334] Understanding that the Clean Power Plan had "departed from the EPA's traditional understanding of its authority under section 111 of the CAA" by selecting a BSER that "encompass[ed] measures the EPA had never before envisioned in promulgating performance standards under CAA section 111," EPA repealed the Clean Power Plan.[335] In its place, EPA promulgated emission guidelines for existing coal-fired steam generating units that determined that heat-rate (efficiency) improvements at the unit itself were the BSER.[336] But this second attempt at regulation was not without issues. First, the CO_2 emission reductions that would be gained by the ACE Rule were small, particularly when compared to the Clean Power Plan's projected emission reductions from generation shifting.[337] Second, there was a concern (called the "rebound effect") that because of the efficiency improvements that would be made at a unit under the ACE Rule, the unit might end up operating more, resulting in an increase in overall emissions.[338]

Several states and environmental groups challenged the ACE Rule, and the D.C. Circuit struck it down because EPA had in the ACE Rule rejected generation shifting as a BSER.[339] The Supreme

[334] 84 Fed. Reg. at 32,520.

[335] *Id.* at 32,523.

[336] *Id.* at 32,525.

[337] *Compare* 84 Fed. Reg. at 32,561, Table 3 (showing projected reductions in CO_2 emissions from the ACE Rule of 12 million tons in 2025 and 11 million tons in 2030 relative to the baseline) *with* 80 Fed. Reg. at 64,924, Tables 15 & 16 (showing projected reductions in CO_2 emissions from the Clean Power Plan of 232-265 million tons in 2025 and 413-415 million tons in 2030 relative to the baseline).

[338] *See* 84 Fed. Reg. at 32,542-43.

[339] *Am. Lung Ass'n v. EPA*, 985 F.3d 914 (D.C. Cir. 2021), *rev'd and remanded by West Virginia v. EPA*, 597 U.S. 697 (2022).

Court reviewed the D.C. Circuit's opinion and reversed it, finding that the Clean Power Plan's generation shifting approach was unlawful and exceeded EPA's authority under section 111.[340]

Following the Supreme Court's decision in *West Virginia v. EPA*, EPA repealed the ACE Rule and replaced it with the Carbon Pollution Standards that are at issue in the Proposed Repeal Rule.[341] In the Carbon Pollution Standards, EPA rejected as the BSER the heat-rate and efficiency improvements approach from the ACE Rule, even though heat-rate and efficiency improvements meet section 111's requirements that a performance standard be achievable, cost-effective, and based on adequately demonstrated technology. EPA rejected heat-rate improvements because they "provide negligible CO_2 reductions at best and, in many cases, may increase CO_2 emissions because of the 'rebound effect.'"[342] EPA then decided to "reevaluate whether other technologies constitute the BSER."[343]

As discussed in detail in Section II of these comments, EPA's search for more meaningful emission reductions led EPA to unlawfully stretch to identify BSERs that were outside the scope of section 111. For several subcategories of fossil fuel-fired EGUs, EPA set NSPS and presumptive emission standards for EGUs that were not achievable and were based on 90 percent CCS, which is neither adequately demonstrated nor cost effective.[344] EPA also returned to its impermissible generation shifting ways, identifying 40 percent natural gas co-firing as the BSER for existing medium-term coal-fired EGUs, in direct contravention of the Supreme Court's holding in *West Virginia v.*

---

[340] *West Virginia v. EPA*, 597 U.S. at 735-36 (holding the generation shifting BSER in CAA was not within the authority Congress granted to EPA in section 111).

[341] 89 Fed. Reg. at 39,798.

[342] *Id.* at 39,836.

[343] *Id.*

[344] *See* 90 Fed. Reg. at 25,769-73.

EPA.[345] Moreover, the presumptive emission standards based on this BSER were also not achievable because most coal-fired EGUs do not have access to any natural gas, and those that do have access to some natural gas, do not have access to the amounts sufficient to co-fire at this level, and "it is unlikely that the pipeline infrastructure necessary can be deployed by the compliance date of January 1, 2030."[346]

3. The History of EPA's Attempts to Regulate GHG Emissions from Fossil Fuel-Fired EGUs Under Section 111 Shows that Including GHGs in the NSPS Program for These Sources May Not Fit Well or Easily Within the Statutory Scheme.

Reviewing EPA's repeated attempts to try to regulate GHG emissions from fossil fuel-fired EGUs demonstrate that regulation of GHGs from those sources under section 111 may be "inconsistent with . . . the Act's structure and design."[347] There are numerous facts that are peculiar to GHGs that do not occur when regulating other air pollutants under section 111. For example, there is a lack of any systems of emission reduction that are both within the scope of section 111 and would achieve meaningful emission reductions. A system of emission reduction that is within the bounds of section 111 – such as heat rate and efficiency improvements – would result in only de minimis emission reductions at best (and at worst emission increases due to the rebound effect). On the other hand, systems of emission reduction that would result in more meaningful emission reductions – such as generation shifting or CCS – fall outside the bounds established by Congress in section 111.[348] In addition, unlike other air pollutants that have a localized effect on health and welfare that can be

[345] *See id.* at 25,773-75; *West Virginia v. EPA*, 597 U.S. at 728 n.3 ("doubt[ing]" EPA could "simply requir[e] coal plants to become natural gas plants" and noting "EPA has never ordered anything remotely like that").

[346] 90 Fed. Reg. at 25,774.

[347] *UARG v. EPA*, 573 U.S. at 321.

[348] 90 Fed. Reg. at 25,766 (noting "the control options available to reduce GHGs from fossil fuel-fired EGUs are not permissible as BSER, not adequately demonstrated, cost unreasonable, or potentially ineffective in reducing emissions").

remedied through imposition of the NSPS, the effect of GHGs on health and welfare is global in nature.[349]

All of these problems that EPA has encountered over the ten years it has attempted to regulate GHGs from fossil fuel-fired EGUs perhaps "should . . . alert[] EPA that it ha[s] taken a wrong interpretive turn."[350] While EPA "cannot change the law" of section 111, it "may change its own conduct."[351] After ten years of trying, it may be time for EPA to conclude that regulating GHG emissions from fossil fuel-fired EGUs under the NSPS program is "inconsistent with the statutory scheme," in which case EPA should exercise its "authority to exclude greenhouse gases from the class of regulable air pollutants" under section 111 for fossil fuel-fired EGUs.[352]

It should be noted that the Supreme Court's decision in *American Electric Power Co. v. Connecticut*[353] does not foreclose EPA from exercising its authority to exclude GHGs from the NSPS program for fossil fuel-fired EGUs. In *Utility Air Regulatory Group*, the Supreme Court discussed regulation of GHGs from power plants under the NSPS program.[354] There, the Court noted that the NSPS program was "not at issue here" and further noted "that no party in *American Electric Power* argued [the NSPS program] was ill suited to accommodating greenhouse gases."[355] But no party made this argument at that time because EPA had not yet promulgated regulations to address GHG emissions from fossil fuel-fired EGUs under section 111. *American Electric Power* was decided in 2011,

---

349 *Id.* at 25,767 (noting "[u]nlike other air pollutants that can have a localized or regional impact and direct consequences to human health, GHGs are global pollutants").

350 *UARG v. EPA*, 573 U.S. at 328.

351 *Id.* at 327.

352 *Id.* at 319.

353 *Am. Elec. Power Co. v. Connecticut*, 564 U.S. 410 (2011).

354 *UARG v. EPA*, 573 U.S. at 319 n.5.

355 *Id.*

and EPA's first NSPS addressing GHG emissions from fossil fuel-fired EGUs came four years later in 2015. No one knew at that time the 10-year journey that EPA would embark on to attempt to regulate GHG emissions from EGUs under section 111. It was not until after all of these repeated attempts that it began to become apparent that section 111 might indeed be "ill suited to accommodat[e] greenhouse gases."[356] These dicta statements in a footnote cannot bind EPA to continuing to try to regulate GHGs from fossil fuel-fired EGUs if it determines that such regulation simply does not work within the CAA's structure and design.[357]

* * *

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

Dated: August 7, 2025

/s/ *Allison D. Wood*
Allison D. Wood
Makram B. Jaber
McGuireWoods LLP
888 16th Street, N.W., Suite 500
Washington, D.C. 20006
(202) 857-2420
awood@mcguirewoods.com
mjaber@mcguirewoods.com
Counsel for the Power Generators Air Coalition

[356] *Id.*

[357] It should also be noted that the Supreme Court made clear in *American Electric Power* that Congress providing EPA with the authority to regulate GHGs in the CAA is what displaced federal common law; EPA does not have to exercise that authority for the displacement to occur. *Am. Elec. Power*, 564 U.S. at 425-26.

Attachment 1

Analysis of Carbon Capture Utilization and Sequestration Technology As BSER Under the 2024 Greenhouse Gas (GHG) and New Source Performance Standards for Fossil-Fired EGUs

Prepared by

J. Edward Cichanowicz
Consultant
Saratoga, CA

Michael C. Hein
Hein Analytics, LLC
Whitefish, MT

Prepared for the

American Public Power Association
Midwest Ozone Group
Power Generators Air Coalition

August 4, 2025

Table of Contents

List of Figures

List of Tables

1 Introduction and Summary

On June 17, 2025, the Environmental Protection Agency (EPA or Agency) issued its proposed *Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units* rule.[1] The Proposed Rule, under its primary approach, seeks to repeal all greenhouse gas (GHG) emission standards for fossil-fueled power plants.

This report supplements technical comments submitted in the docket of the proposed 2023 GHG NSPS rulemaking.[2] Since the submission of the 2023 report, several references have become available, among these submissions by SaskPower regarding Boundary Dam Unit 4, additional capital cost from a completed Front End Engineering Design (FEED) study, and an update of CO_2 pipeline permits in several states.

This report addresses five topics. Section 2 describes how experience with carbon capture utilization and storage (CCUS) at industrial scale does not reflect utility duty, as most industrial applications deploy CCUS as a slipstream of the source rather than integrated for 24x7 duty over the load cycle. Section 2 discusses how slipstream duty provides flexibility to avoid or minimize complications due to load following – and highlights that utility applications at Petra Nova and – to a lesser extent – SaskPower Boundary Dam Unit 4 function as a slipstream.

Section 3 summarizes detailed studies of CCUS applications. Ten such FEED studies for coal-fired and nine for natural gas/combined cycle (NGCC) firing are identified, denoting those completed and results in the public domain. Although many FEED studies are in progress and their results have not been released, there are no definitive, funded CCUS demonstration projects underway.

Section 4 of the report explores the operating experience of SaskPower Boundary Dam Unit 4, which is re-evaluated, considering information submitted by the project operator that had not been previously disclosed. New information shows Boundary Dam Unit 4 CCUS enjoyed a flexibility in duty that would not qualify as a commercial demonstration in the context of the proposed GHG rule. Similarly, the Petra Nova experience is re-assessed in this manner.

Section 5 discusses the capital cost estimates of CCUS processes, updated to include one additional coal-fired unit not available in August 2023, and with costs for all studies presented in the same cost year (2022). These results show the capital cost for CCUS, as applied to either coal-fired or NGCC generation, require as much or more capital than necessary for a new, greenfield state-of-the-art coal-fired or NGCC generating asset without CCUS.

---

[1] 90 Fed. Reg. 25,752 (June 17, 2025) (Proposed Rule).
[2] E. Cichanowicz & M. Hein, Technical Comments on the Carbon Capture Utilization and Sequestration Aspects of the Proposed New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule, August 7, 2023. Hereafter 2023 Technical Comments.

Section 6 presents an update of the permitting activities for CO_2 pipelines in the Midwest, summarizing the recent permit denials and project cancellation for Navigator Ventures, and permit denial for Wolf Carbon Solutions. In contrast, the Summit pipeline has secured permits in Iowa, North Dakota, and Minnesota, but continues to experience resistance and permit rejection in South Dakota. Summit has indicated its intent to continue to pursue access in South Dakota by altering pipeline routing to minimize barriers.

Cumulatively, these five topics, upon being revisited with recent information, further support the conclusion that CCUS for either coal-fired or NGCC application is not commercially demonstrated.

2 Discussion of Relevant Reference Cases

The 2024 Carbon Pollution Standard (CPS) designated CCUS as the best system of emission reduction (BSER) based on, among other factors, experience with industrial applications. There are two means in which CCUS currently applied on industrial sites fails to reflect utility operation –the process equipment is typically arranged differently and operates as a “slipstream” from the host unit, in contrast to an integrated operating mode.

Two EPA references cited in the 2023 proposed rule – Sears Valley Minerals and Bellingham Energy Center –deploy CCUS as a slipstream.[3]

- Sears Valley Minerals. The Sears site is comprised of three coal-fired units – two generating 27.5 MW and a third at 7.5 MW.[4] Public information suggests CO_2 capture is either intermittent or well below 90%, and the arrangement of three boilers suggests the CCUS process is configured as a “slipstream” that can be bypassed or deployed as needed.[5,6]

- Bellingham Energy Center. In the case of the 386 MW Bellingham facility, a DOE “fact sheet” reports CO_2 removal capability of 800 tons per day[7] as a slipstream.[8] The “fact sheet” suggests the unit operated from 1991 through 2005, with CO_2 removal of “85-95%”.[9] The Bellingham gas flow rate – not specified in the literature – by linked to a 40 MW gas turbine is approximately 280 lb/sec (e.g. GE LM6000), or 1/6th of the approximately 1,700 lb/sec processed by a state-of-the-art J- or H- Class Frame turbine.

---

[3] 88 Fed. Reg. 33,240, 33,292 (May 23, 2023).
[4] Energy Information Agency 860 Data, File 3_1_Generator_Y2021. Operable tab, Rows 9148-9150.
[5] Elmoudir, W. et. al., HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA, Energy Procedia 63 (2): 6156-6165, December 2014.
[6] Specifically, if the CO_2 removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of CO_2 per day – and daily CO_2 removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% CO_2 removal for 35% operating time (perhaps one “daytime” shift).
[7] Elmoudir, W. et. al., HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA, Energy Procedia 63 (2): 6156-6165, December 2014.
[8] Specifically, if the CO_2 removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of CO_2 per day – and daily CO_2 removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% CO_2 removal for 35% operating time (perhaps one “daytime” shift).
[9] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. Available at https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.

Operating CCUS or any environmental control process as a "slipstream" of gas, in contrast to being inseparably linked to the host unit, provides flexibility to manage uncertainties. A slipstream of gas flow can be operated independently of changes to the host unit. This feature enables the environmental control process to avoid issues with load ramping up or down, startup/shutdown, or process "upsets". The ability to maintain a constant gas flow rate isolates the process from these changes – process equipment can be taken off-line during startup/shutdown events, and activated only during well-controlled flow conditions.

Figure 2-1 is instructive on this topic. The figure presents a 3-dimensional model of the CCUS facility designed as a retrofit to Alabama Power NGCC generating units – either Daniel 4 or Barry Unit 6.[10] Figure 2-1 denotes flue gas processing equipment in green and power generation equipment – gas turbines, heat recovery steam generators, and cooling towers - in blue.

Each of the key CCUS process steps is defined in Figure 2-1. The components process flue gas according to a characteristic residence time and gas pressure drop, the latter monitored and input for flue gas fan operation. These process steps are the (a) exhaust gas recirculation (EGR) direct contact cooler, (b) CCS direct contact cooler, (c) CCS absorber, (d) CCS stripper, and (e) CCS and EGR cooling towers.

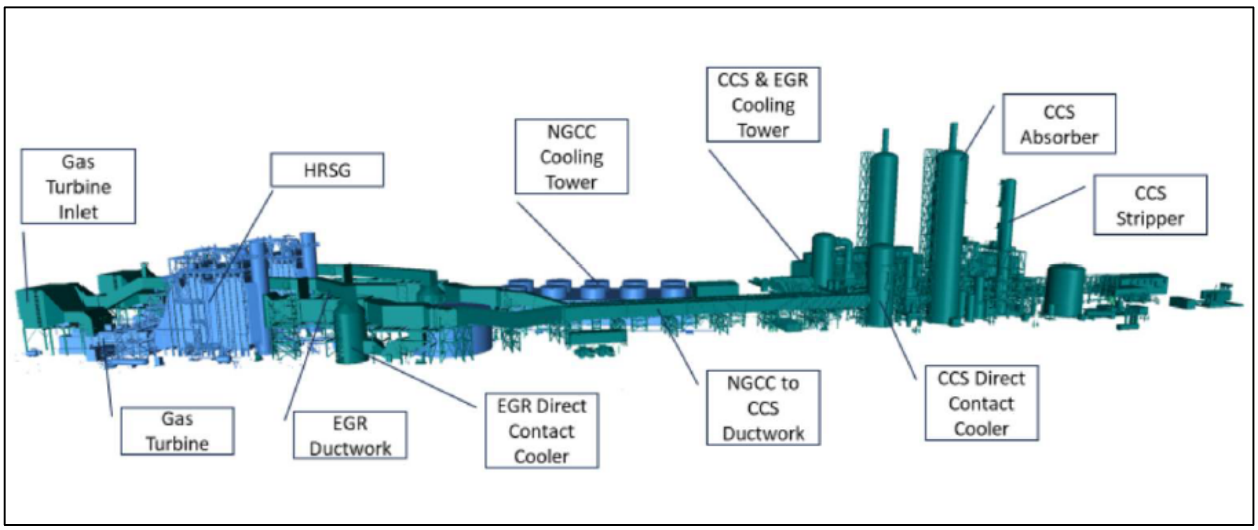


Figure 2-1. Arrangement of NGCC with CCUS Equipped with Exhaust Gas Recirculation

Further, the operation of each process step is determined by a series of subordinate actions, involving the consumption or production of liquid or gaseous media. Figure 2-2 presents a simplified process flow sheet of the carbon capture process for the arrangement in Figure 2-1.

[10] Retrofittable Advanced Combined Cycle Integration for Flexible Decarbonized Generation, presentation to the DOE Carbon Management Conference, August 6, 2024.

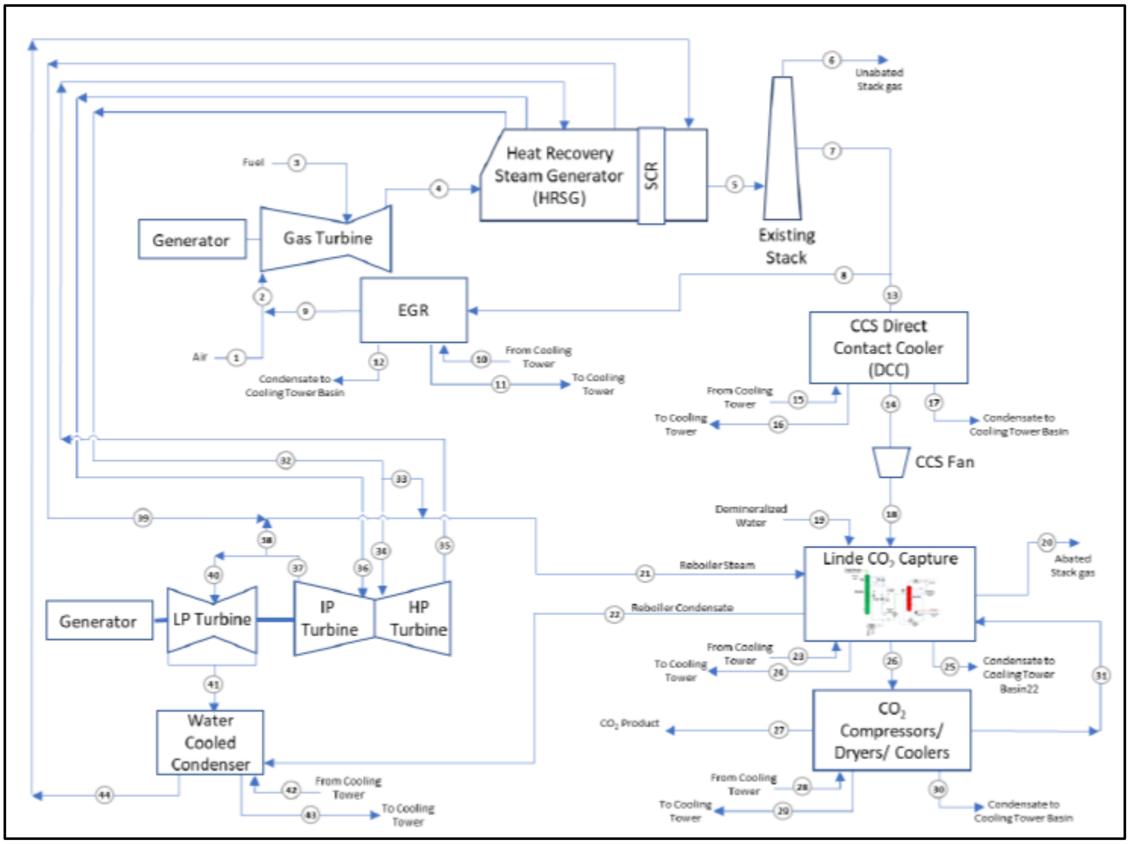


Figure 2-2. Simplified Process Flowsheet: CCUS Process Arrangement Daniel/Barry

As an example, the Linde CO_2 Capture step planned for potential application at Daniel 4 or Barry 6 is designed to process five input and four output flow streams. The five inputs streams are (a) flue gas for processing, (b) demineralized water, (c) reboiler steam for heating, (d) cooling tower effluent for cooling, and (e) partially processed amine streams containing CO_2. The four output steams are (f) condensate to the reboiler for heating, (g) process water to the cooling tower for cooling, (h) processed CO_2 for drying and compression, and (i) effluent flue gas for discharge. Each of these input and output streams operate in a dynamic manner, changing with host unit load, CO_2 concentration, and ambient temperature. Coordination of the steam supply and the flow rate of the liquid amine sorbent that removes CO_2 are key subordinate inputs important to process operation.

For CCUS units integrated 24 x 7 with a host boiler, process control systems must instruct these subordinate input and output flows to change with boiler operation. The characteristic time for some of the changes can be minutes or less.

Further, the mass rate of CO_2 production must be synchronized with the (not shown) steps for compression and delivery to the high-pressure pipeline.

The design challenge is ensuring process components—especially the CO_2 absorber and stripper—respond immediately to changing conditions rather than reacting to outdated data from 15-30 minutes earlier. Achieving such coordinated action is feasible– but rarely in a First-of-a-

Kind (FOAK) concept. Several iterations of the "nth" design will be required to be tested in authentic duty.

Conclusion: Experience with CCUS on an industrial process, or at utility demonstration with process duty on a flue gas "slipstream", does not represent the dynamic actions required for 24 x 7 duty on a host utility boiler. Slipstream success does not imply full-scale utility power plant success.

3 Status of FEED Studies

The proposed rule reports that several planned CCUS installations on coal-fired units have been abandoned[11] or faced challenge as to feasibility, after completion of FEED studies. Section 3 summarizes publicly available results from FEED studies and reports on project status.

The FEED study is a key CCUS decision metric. FEED studies (a) develop in more detail process flowsheets and/or equipment arrangement drawings, and (b) solicit budgetary quotations from suppliers to establish cost and availability. Some FEED studies include a construction plan, addressing the fabrication and delivery of the critical components to the site. EPA rightfully identifies these FEED studies as "…projects in the early stages of assessing the merits of retrofitting coal steam EGUs with CCS technology", with potential for "…the application of CCS to existing gas facilities".[12]

The follow-on to a FEED study and precursor to a demonstration is a detailed "Specification" study, which defines equipment attributes, layout, and an operating plan. These results are used to develop a request for proposal to solicit from a supplier a "firm" process design and cost. This "Specification" step has been completed only for SaskPower Boundary Dam 3 and Petra Nova.

3.1 Coal-Fired FEED Studies

Table 3-1 lists ten FEED studies addressing coal-fired generation. Table 3-1 describes the host unit features, the CO_2 capture technology evaluated, the targeted CO_2 removal, and the fate of CO_2 (e.g., either enhanced oil recovery or storage). FEED studies for the first six projects are publicly available; none of these projects will advance to follow-on studies. As noted by EPA in the proposal, the FEED study for Cleco's Project Vault was abandoned in late 2024, and a key participant in Minnkota Power's Project Tundra similarly withdrew from further participation.[13]

FEED studies for the remaining sites are in various stages of planning and execution, starting with Springfield City Water Light & Power (CWL&P) securing funding for a study at Dallman Unit 4.[14] The FEED studies for Duke Energy Edwardsport and Navajo Transitional Energy Company are in progress and are anticipated to be released in 2026. Cost results from the six publicly available reports summarizing these FEED studies are presented in Section 4.

[11] 90 Fed. Reg. 25,772. (June 17 2025) (Proposed Rule).
[12] Steam EGU TSD. P. 23.
[13] 90 Fed. Reg. 25,772. (June 17 2025) (Proposed Rule).
[14] Brownstein, cc, Phase III Update: Large Pilot Testing of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Coal-Fired Power Plant, presented to FECM/NETL 2024 Carbon Management Research Project Meeting August 5, 2024.

Table 3-1. CCUS FEED Study Status: Coal-Fired Application

Station/ Unit	Capacity, MW [gross(g) or net (n)] (Layout, Aux Steam	Capture Technology:	CO_2 % Capture, MTs/h	CO_2 Fate
Milton R. Young/ Minnkota Power Co-op	1: 250 MW (n) 2: 470 MW (n) Note: "net" basis prior to CCUS	Econamine FG$^+$	90% target (11,000 MT/d)	Storage in saline reservoir, or EOR
Dry Fork/ Basin Electric	440(n) prior to CCUS	MTR Polaris membrane	70% target	"Carbon Valley" hub: Saline storage, EOR
NPPD: Gerald Gentleman	700 MW (2 x 350 MW) 642 MW w/CCUS	Ion Clean Energy solvent	90%, or 638K lbs/h (2.2 M MT/y)	EOR
Enchant Energy/San Juan 1-4	U1: 370 (n) U4: 507 (n)	MHI amine solvent	90%	Storage, with EOR to Permian Basin alternate
Prairie State Generating Company	816 (g) Aux power: 85.5 MW	MHI KM-CDR	95%, 8.46 MT /y	Off-site saline storage
SaskPower Shand	305(g) 279 (n)	KM CDR Process	90%	EOR at Weyburn, Midale
Cleco Power Madison Unit 3	605 MW(n) (CFB boiler, 70/30 pet coke/Illinois coal)	MHI amine solvent	95%	Storage in geologic formations
Duke Edwardsport	618 MW IGCC	Honeywell Advanced Solvent	95%	Storage on-site in geologic formations
Navajo Transitional Energy/Four Corners	1,500 MW Four Corners Station	MHI amine solvent	95% (10 million Mtons/y	EOR or Saline Storage
CWL&P Dallman U 4	200 MW	Linde/BASE Solvent	TBD	Storage in Illinois Basin

3.2 Combined Cycle

Table 3-2 lists nine FEED studies addressing NGCC generation. Similar to the case for coal, Table 3-2 describes the host unit features, the CO_2 capture technology evaluated, the targeted CO_2 removal, and the fate of CO_2 (e.g., either enhanced oil recovery or storage).

Table 3-2. CCUS FEED Study Status: NGCC Application

Station/ Unit	Capacity, MW [gross(g) or net (n)] (Layout, Aux Steam	Capture Technology:	CO_2 % Capture, MTs/h	CO_2 Fate
Golden Spread/ Mustang	480 (n), w/o CCUS 399 (n) w/CCUS (2 x 2 x 1) Steam: aux boiler	2nd gen solvent (piperazine)	90% 190 MT/h	EOR
Rayburn Energy	594(n) w/o CCUS 460 (n) w/ CCUS (2 x 2 x 1) Steam: turbine	Generic MEA conventional absorber/ stripper	85% 129 MT/h	Primary: saline fields. Secondary: local EOR.
Elk Hills	550(n) w/o CCUS 515 (n) w/CCUS 2 x 2 x 1 (w/duct-firing) Steam: aux boiler	Econamine FG Plus+	90% of total effluent (74% CO_2 aggregate or 167 MT/h	Storage below the plant site
Daniel 4	529(n) w/o CCUS 450 (n) w/CCUS (2 x 2 x 1) Steam: turbine	Linde-BASF OASE® blue solvent	90%	Saline storage at Kemper County, MS
Barry 6	525(n) w/o CCUS 446 (n) w/CCUS (2 x 2 x 1) Steam: TBD	Linde-BASF OASE® blue solvent- EGR to elevate CO_2.	95+% MTs removal TBD	Same as Daniel 4
Calpine Deer Park (5 units)	5x180 CT + 1 Steam. (n) w/o CCUS (1,175 MW). CCUS aux power 75 MW.	Shell Cansolv (2nd Generation)	95% ~600 MT/h (6.5 MT/yr)	Storage at Gulf Coast sites
Calpine Delta Energy Center	857 MW (3 x 3 x 1) 3 Siemens W501F, 3 Deltak HRSGs, Toshiba Turbine	Ion Clean Energy Sorbent	95% or 2.4 MTa	Storage
TECO Polk Power Unit 2	1,168 MW (4x4x1) (Four GE 7FA turbines)	Ion Clean Energy Sorbent	95% or 3 MTa	TBD
LG&E Cane Run Unit 7	640 MW (n) Two Siemens SGT6-5000F turbines; 2 x 2 x 1	University of Kentucky water-lean solvent	95%	TBD

Of the nine FEED studies in Table 2, five have been completed with results available in the public domain. The status of these FEED studies is as follows:

- Completed, results in the public domain, no further actions planned. Golden Spread, Rayburn Energy, and Elk Hills –
- Completed, results in public domain, further actions pending. Daniel 4 and Barry 6.
- Results in progress, not yet available for release. Calpine Deer Park and Delta,[15] Tamp Polk Power, LG&E/KU Cane Run – the latter anticipating a completion date in 2025 and results publicly available in 2026.

In summary, of nine FEED studies on NGCC, four are completed with no further actions planned; two completed, but further actions are pending results in progress. Four studies are in progress, with results not available, and plans are dependent on the study outcome.

These activities show interest in deploying CCUS to NGCC, but as conceptual exercises. Notably, there are no operating CCUS applications or definitive, funded plans for commercial deployment.

Conclusion. Of the nineteen FEED studies either completed or in progress, none have led to an actual, funded CCUS demonstration projects. Several such studies are in progress and are anticipated to be completed in 2026. To date, none are committed to a demonstration.

[15] https://www.calpine.com/carbon-capture-and-sequestration-ccs/feed-studies/.

4 North American Utility Scale Process Experience

The EPA in the 2024 rulemaking proposed both SaskPower Boundary Dam Unit 3 and the NRG Petra Nova project provided sufficient experience to enable CCUS to be designated "adequately demonstrated at a capture rate of 90%."[16] Both demonstrations provide experience but are inadequate to establish CCUS as demonstrated and commercially available.

Section 4 presents the status of these projects updated with recently available or revised information.

4.1 SaskPower Boundary Dam 3

SaskPower has operated CCUS at Boundary Dam Unit 3 since 2014, employing an early generation Cansolv CO_2 process. Inherent to the Cansolv process is an SO_2 removal step to limit emissions to less than 10 parts per million (ppm) that, combined with improved particulate matter control, protects the amine sorbent from degradation.

Operating details of this unit are summarized in a previous report.[17] Several days preceding the close of the comment period for the 2023 proposed rule SaskPower shared additional details of the Unit 3 CCUS design and operation,[18] some of which not previously released to the public. In their August 2, 2023, filing SaskPower noted:

- <u>Amine Sorbent Compromise</u>. As cited in earlier publications,[19,20] the amine-based sorbent that captures CO_2 is compromised by contamination of fly ash from the particulate collector, reducing CO_2 capture effectiveness. SaskPower concedes this shortcoming and notes that eight years of development were required to improve operations to a state not yet fully disclosed.[21]

- <u>Reduced Flue Gas Processing Rate</u>. The demonstration facility operates below full gas flow capacity, except for a brief multi-day period after startup. This reveals an undisclosed design margin in the process.

[16] 89 Fed. Reg. 39,847 (May 9, 2024) (Final Rule).
[17] August 7, 2023 Technical Comments.
[18] SaskPower. Docket ID No. EPA–HQ–OAR–2023–0072: SaskPower Correction of Reference to Boundary Dam Unit 3 Emissions Performance in Proposed Rule. August 4, 2023. Document ID No. EPA-HQ-OAR-2023-0072-0687. Hereafter SaskPower 2023 Correction.
[19] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability.*
[20] Pradoo, P., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility*
[21] SaskPower 2023 Correction.

- Slipstream Features. In a disclosure not previously shared or widely disseminated, Boundary Dam staff concede that a fraction of the flue gas from the Unit 3 boiler is not processed but bypassed – for purpose of reliability. The fraction of flue gas bypassed is 5% of total flow – or 58,325 actual cubic feet per minute (acfm) of the total 1,166,497 acfm.[22]

- CO_2 Optimized for 65-70% CO_2 Capture to Ensure a Higher Reliability. SaskPower does not describe what steps it takes to improve reliability at the expense of CO_2 capture. One likely means to do so is lowering the amine sorbent recirculation rate, which may be necessary depending on recirculation equipment reliability or a change in sorbent properties. This action can minimize reagent handling problems that could compromise reliable operation. A second means to compromise CO_2 removal to ensure high reliability is to reduce the volume of gas flow processed.

Each of these revelations - eight years after unit startup and numerous publications – document that additional work must be accomplished through numerous "Nth-of-a-kind" demonstration tests. The "takeaway" is that the Boundary Dam experience does not demonstrate CO_2 removal of 90%; rather that 65-70% CO_2 can be achieved with a caveat on reliability.

A graphic depiction of the reliability challenges addressed by SaskPower is the reported CCUS process availability, by quarter, since late 2022. These data – acquired from the SaskPower Boundary Dam blog – present the availability average per quarter, from Q2 2022 through 2Q 2025.[23] (Data from prior quarters is not reported in this manner and not available for comparison). Figure 4-1 shows the SaskPower target of 75% - their selection for their conditions – is typically met, but under the conditions that not all the flue gas is to be processed.

A CCUS process reliability of 90% is likely required to support a 90% CO_2 removal for the domestic U.S. coal-fired fleet. This GHG target – even under the conditions where all flue gas is not treated – is attained by Boundary Dam in 6 only of 13 quarters.

---

[22] Giannaris, S. et. al., Implementing a second-generation CCS facility on a coal fired power station – results of a feasibility study to retrofit SaskPower's Shand power station with CCS, available at: https://ccsknowledge.com/pub/Publications/2020May_Implementing_2ndGenCCS_Feasibility_Study_Results_Retrofit_SaskPower_ShandPowerStation_CCS.pdf.. Hereafter Giannaris 2023.
[23] https://www.saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q2-2025

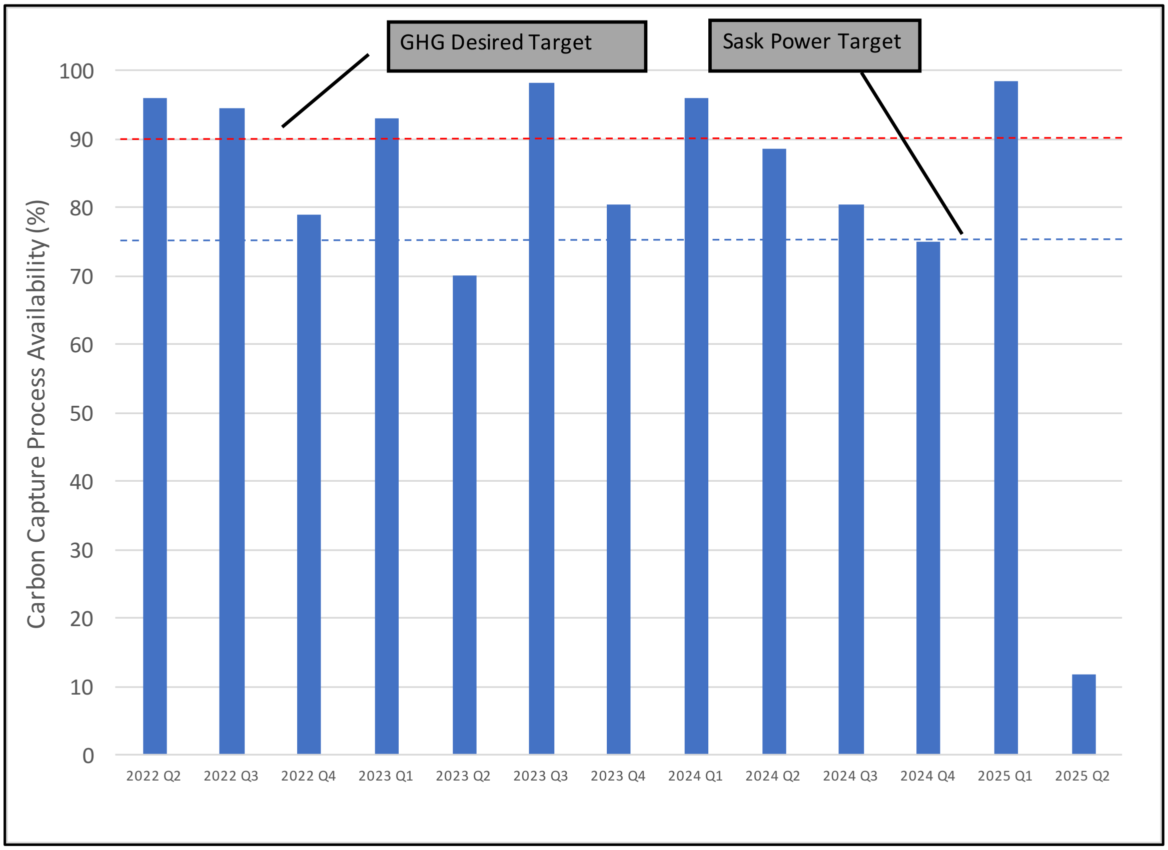


Figure 4-1. SaskPower Boundary Dam Unit 4 Carbon Capture Process Availability: 2002-2025

4.2 Petra Nova

NRG, owners of the W. A. Parish Generating Station, operated the Petra Nova CCUS process at Unit 3 from March 2017 through March 2020. The operating details of this unit are reported in previous technical comments.[24]

Petra Nova operates as a slipstream process, in that a constant flow rate of flue gas is extracted from the host unit, regardless of the duty cycle of the host boiler. Petra Nova thus enjoys the same flexibility and advantage of the industrial applications at Searles and Bellingham and (as recently disclosed) Boundary Dam Unit 4. Consequently, the reported 92% CO_2 removal over the three years does not reflect actual, full-scale duty if integrated into the host boiler duty cycle.

Further invalidating Petra Nova as representative of actual, full-scale utility duty is the retrofit of the combined cycle generating unit to explicitly provide, via the HRSG, a reliable steam source for reagent regeneration. This constant, unchanging source of steam ensures available heat to regenerate CO_2 from the sorbent – regardless of the host unit's operations. Thus, some of the

[24] August 7, 2023 Technical Comments.

challenges of maintaining high CO_2 removal during unit variability such as load changes are eliminated.

Two limitations in the report—unchanged since August 2023—hinder transparent cost evaluation and levelized cost estimates per tonne of CO_2 removal. First, the combined cycle generator retrofit to provide reliable steam affects CO_2 capture economics, but detailed process costs aren't presented in the final report, making CCUS capital and operating cost assessment difficult. Second, the allocation of construction and balance-of-plant costs between the combined cycle and CCUS budgets remains unclear, as does the accounting of value from the additional gas turbine power generated and its impact on CCUS operating costs.

Most significantly, as noted in the August 2023 Comments, the actual cost-per-tonne of CO_2 removal during process operation has not been disclosed.

In summary, the design and operation of the Petra Nova process –on the surface successful in achieving the 90% CO_2 reduction – does not support the proposition that such CO_2 capture can be reliably broadly achieved.

Conclusion. The Boundary Dam Unit 4 and the Petra Nova CCUS demonstrations, although contributing significantly to the CCUS knowledge bases, do not adequately demonstrate CCUS for utility application. Boundary Dam Unit 4, after eight years of optimization, is limited to a CO_2 reduction target of 65-70% to assure high reliability. Petra Nova reliability benefits from coincident retrofit of a NGCC process and HRSG to reliably supply process steam. These conditions are unsatisfactory for broad CCUS deployment to the domestic fleet.

5 Update of CCUS Cost Estimates

Section 5 updates cost estimates for CCUS, incorporating an additional FEED study released since the August 2023 Technical Comments. As noted in Section 3, there are only two verified capital costs for CCUS – SaskPower Boundary Dam Unit 3 and Petra Nova (the shortcomings of the Petra Nova cost are discussed in the previous section). All other costs are estimates.

Figures 5-1 and 5-2 present CCUS capital cost *per net generating capacity after CCUS* for coal-fired and NGCC applications, respectively. A total of 12 cases are presented – eight addressing coal-fired duty and four addressing NGCC application. The costs are all reported in 2022 dollars. The coal-fired costs include SaskPower Boundary Dam 3 and Petra Nova results, in addition to the six FEED studies. NGCC applications include only four sites for which results are publicly available. For both categories, the cost of a new generation technology – subcritical pulverized coal and NGCC with triple reheat HRSG – is presented for comparison.

5.1 Coal Fired

Figure 5-1 presents CCUS cost as reported for SaskPower Boundary Dam Unit 4,[25] SaskPower Shand,[26] Petra Nova,[27] Basin Electric Dry Fork,[28] Minnkota Milton R. Young,[29] Enchant Energy San Juan,[30] Nebraska Public Power District Gerald Gentleman,[31] and Prairie State.[32]

[25] Coryn, Bruce, *CCS Business Cases*, International CCS Knowledge Center, Aug 16, 2019, Pittsburgh, PA.
[26] Giannaris 2023.
[27] Final Scientific/Technical Report, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project,* DOE Award Number DE-FE0003311, Petra Nova Parish Holdings LLC, March 31, 2020, Report DOE-PNPH-03311. Hereafter Petra Nova 2020 Final Report.
[28] Commercial-Scale Front-End Engineering Design Study for MTR's Membrane CO_2 Capture Process, Final Technical Report, November 10, 2022. Hereafter 2022 MTR FEED Report.
[29] Project Tundra: Postcombustion Carbon Capture on the Milton R. Young Station in North Dakota, NRECA Update, October 2022.
[30] Crane, C., *Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station,* Overall Feed Package Report for DOE Cooperative Agreement DE-FE0031843, September 30, 2022.
[31] Carbon Capture Design and Costing: Phase 2 (C3DC2), Final Project Report, Final Scientific/Technical Report, DOE-FE0031840, March 2023.
[32] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816-MWe Capture Plant Using Mitsubishi Heavy Industries America Post-Combustion CO_2 Capture Technology, August 2, 2022. Hereafter 2022 Prairie State FEED Report.

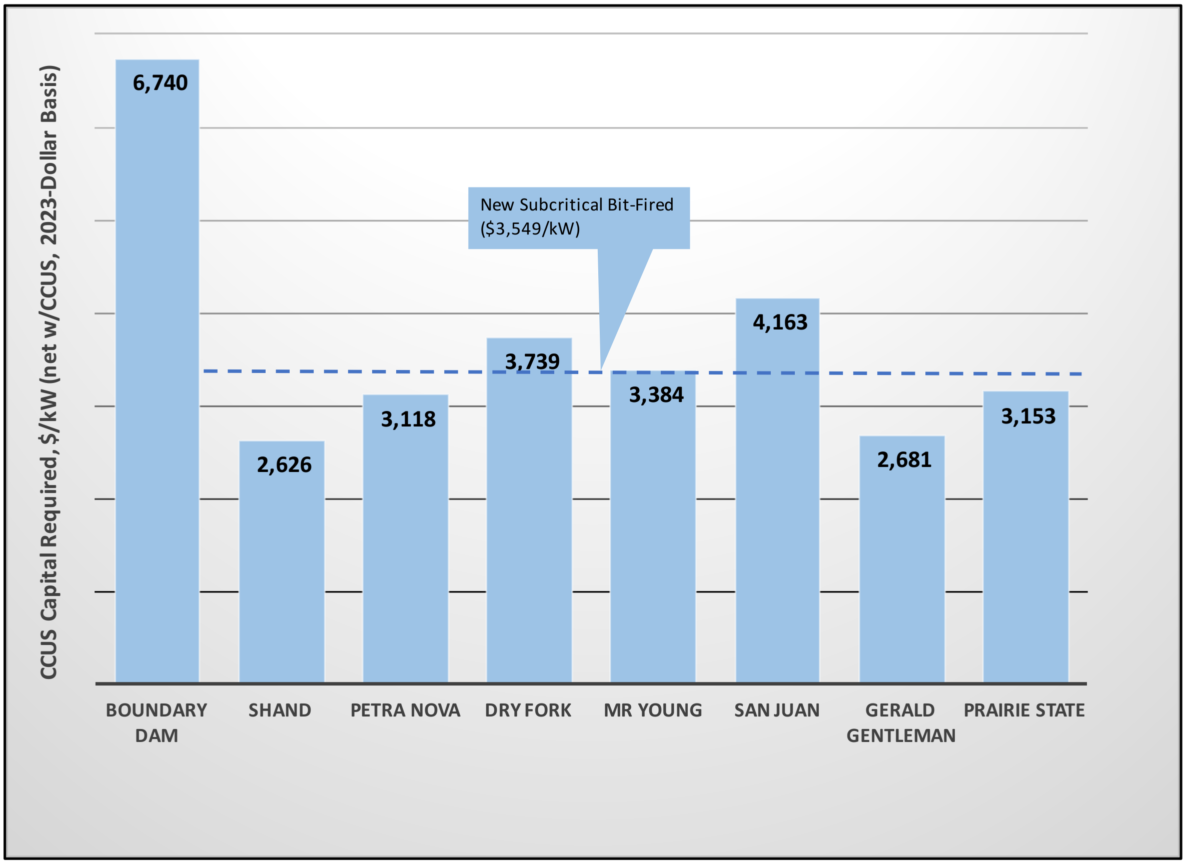


Figure 5-1. CCUS Capital Cost as Reported for Coal-Fired Demonstrations, FEED Studies

Figure 5-1 also reports capital cost for a hypothetical state-of-the-art subcritical coal-fired unit evaluated by the National Energy Technology Laboratory (NETL): 650 MW (net) with an 8,849 Btu/kWh net heat rate.[33]

Data in Figure 5-1 varies widely by site. Capital cost *per net generating capacity after CCUS* for four FEED studies is less than the cost for new coal-fired generation. In comparison, the CCUS cost for three FEED studies and Boundary Dam equals or exceeds that for new coal-fired generation. The Boundary Dam cost is atypical, given the "first-of-a-kind" status and relatively small generating capacity. An instructive cost metric to consider is the average of the FEED studies' cost results, excluding both Boundary Dam Unit 4 and the lowest of coal application (SaskPower Shand). These six cost estimates equate to $3,373/kW – almost identical to the cost of a new state-of-the-art subcritical coal-fired generator without CCUS.

It is important to recognize capital cost data in Figure 5-1 reflects only CO_2 capture, compression, and preparation for transport from the power station fence line. Capital and operating cost for CO_2 transport to the sequestration or EOR site, injection, and plume

[33] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL Report 2023-4320, October 14, 2022. Hereafter 2022 Bituminous/NGCC CCUS Retrofit.

monitoring are not included. Sites requiring minimal pipeline length will still incur significant cost for the sequestration step.

5.2 NGCC Applications

Figure 5-2 presents the capital cost estimated by FEED studies of NGCC applications reported in the public domain. These FEED studies address the Panda Sherman,[34] Golden Spread Mustang,[35] Daniel 4,[36] and Elk Hills[37] generating units.

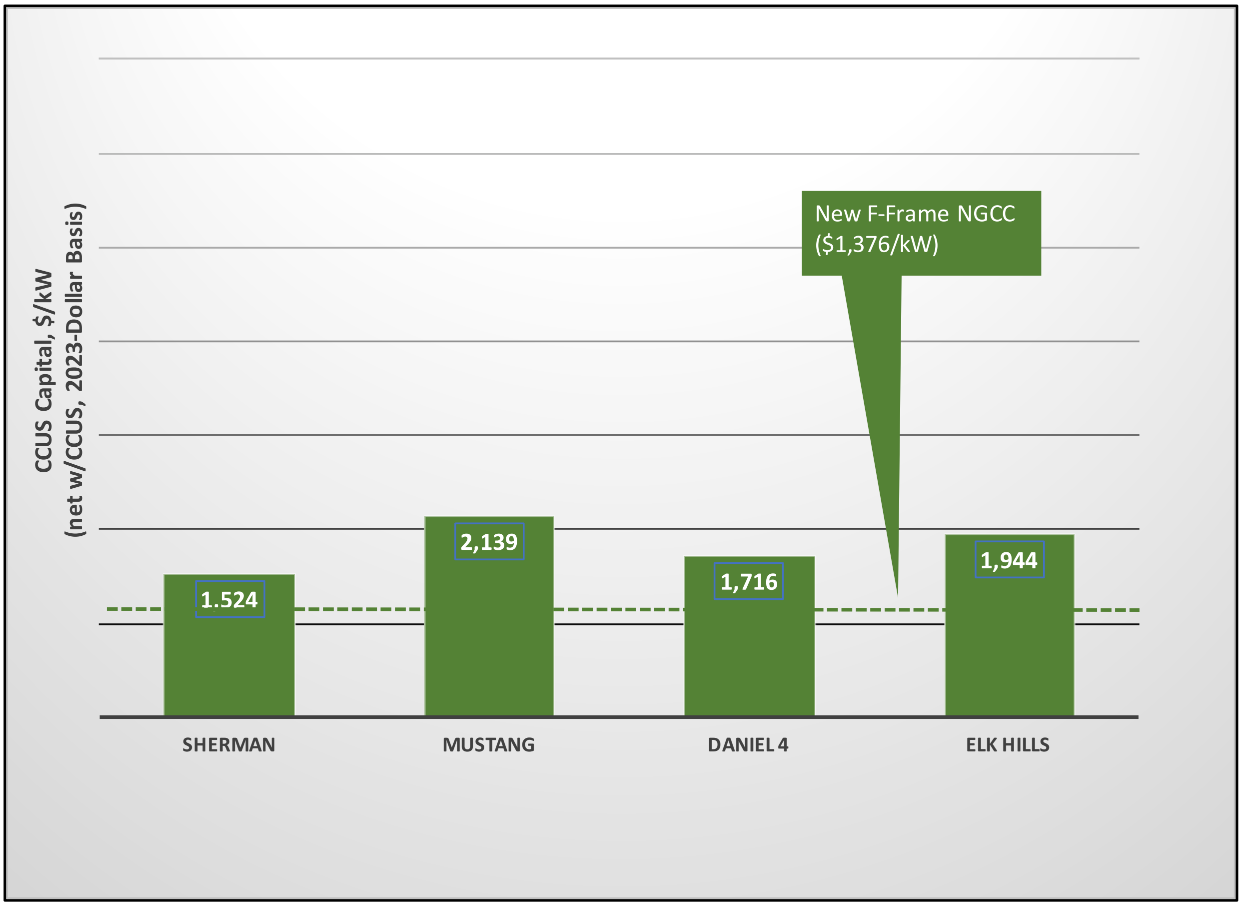


Figure 5-2. CCUS Capital Cost as Reported for NGCC FEED Studies

[34] Panda Sherman 2022 Final Report.
[35] Rochelle, G., Piperazine Advanced Stripper (PZAS™) Front End Engineering Design (FEED) Study, DE-FE0031844, 2022 Carbon Management Research Project Review, August 17, 2022.
[36] Lunsford, L., et. al., Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant, Final Scientific/Technical Report, per DE FE0031847, September 30, 2022. Hereafter 2022 Daniel FEED Report.
[37] Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant, Agreement DE-FE0031842, for US DOE/NETL, January 2022. Hereafter 2022 Elk Hills FEED Report.

Figure 5-2 also presents the capital cost for a hypothetical state-of-the-art NGCC generating unit without CCUS, as evaluated by NETL.[38] The NETL study estimates capital cost for F-Class and H-Frame combustion turbine designations, with cost for a "2 x 1" F-Frame design capable of 727 MW (net) and 6,363 Btu/kWh heat rate shown in Figure 5-2 as $1,376/kW.

Capital costs in Figure 5-2 vary widely by site, driven by, among other factors, the steam source for CCUS. For example, CCUS capital projected for Panda Sherman ($1,524/$/kW $_{\text{(net, with CCUS)}}$ is the lowest, with a key contributing factor being the use of the existing HRSG to provide steam for CCUS duty – but at the cost of a generating capacity penalty. Conversely, the highest capital cost (~$2,000/$/kW $_{\text{(net, with CCUS)}}$) is estimated for two units (Mustang, Daniel 4), with contributing factors being the need for auxiliary boilers to provide steam and preserving generating capacity.

The average of the four FEED studies – albeit representing different design concepts to provide CCUS steam –is $1,831/$/kW $_{\text{(net, with CCUS)}}$. This value represents a 30% premium to the cost developed by NETL for a 727 MW unit without CCUS.

<u>Conclusion</u>. The cost for CCUS applied to either coal-fired or NGCC generating assets approximates or exceeds that for stand-alone generation, without CCUS. For coal-fired assets, the cost for a new 650 MW subcritical unit and the average of the CCUS cost results (the latter as $/kW$_{\text{(net, with CCUS)}}$ from six FEED studies is almost identical, at $3,373/kW$_{\text{(net, with CCUS)}}$. For NGCC the cost of the CCUS process - based on an average of four FEED studies – at $1,831/kW$_{\text{(net, with CCUS)}}$ exceeds by 30% the cost of new 727 MW greenfield generation.

[38] Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 3, DOE/NETL-2023/3848, May 31, 2023. Hereafter 2023 NGCC CCUS Retrofit.

6 CO_2 Pipeline Permitting Issues

Broad CCUS deployment will require a significant increase in CO_2 pipeline capacity. Securing new pipelines requires design, permitting, and construction tasks – all within a time frame that will not delay the entire project. The August 2023 Technical comments presented details of the ongoing permitting conflicts and the delays incurred for certain projects. Section 6 provides a brief update on three notable projects.

The major actors in the pipeline permitting debates are summarized as follows:

- Navigator Ventures[39] proposed 900-mile Heartland Greenway CO_2 pipeline, bisecting Iowa from northwest to southeast and transporting CO_2 to Illinois. The approximate $3.2B project extends a total of 1,300 miles through South Dakota, Nebraska, Minnesota, and Iowa.

- Wolf Carbon[40] proposed 280 miles of pipeline to transport CO_2 from ADM ethanol-producing facilities in eastern Iowa to Decatur, IL, for terrestrial sequestration.

- Summit Carbon[41] plans 700 miles of pipeline in western and northern Iowa to transport CO_2 to North Dakota for existing EOR application. In Iowa alone, the proposed pipeline will cross 30 counties.[42]

Each of these organizations has pursued pipeline permits in several states: Iowa, Minnesota, North Dakota, Nebraska, and South Dakota. The permitting requirements vary significantly by state– Iowa presents perhaps the most structured steps, and Nebraska the least. Landowners cite numerous reasons for resisting access to their property. These include the role of eminent domain, safety due to CO_2 leaks, and concern that agricultural productivity is compromised within pipeline easements – meaning productivity is reduced 15% for corn and 25% for soy.[43]

The status of the pipeline permits as of July 2025 is described subsequently.

---

[39] https://heartlandgreenway.com/about-us/.
[40] https://wolfcarbonsolutions.com/mt-simon-hub/.
[41] https://summitcarbonsolutions.com/project-footprint/.
[42] Proposed Iowa Pipeline Would Cross 30 Counties, Radio Iowa, Aug 20, 2021. https://www.radioiowa.com/2021/08/30/proposed-carbon-dioxide-pipeline-would-cross-30-iowa-counties/.
[43] Pipeline study shows soil compaction and crop yield impacts in construction right-of-way, Iowa state university College of Agricultural and Life sciences, November 11, 2021. Available at https://www.cals.iastate.edu/news/releases/pipeline-study-shows-soil-compaction-and-crop-yield-impacts-construction-right-way.

6.1 Navigator Ventures

Navigator Ventures, in October 2023, canceled the 1,300-mile pipeline project planned to cross five Midwestern states.[44] The company cited the challenging regulatory environment, particularly in South Dakota and Iowa. The permit was denied by South Dakota in September 2023[45] and Navigator requested Iowa to pause the permit application.[46] The permit was also withdrawn for consideration from Illinois.

Landowners and community groups organized against the Navigator project, focusing on concerns regarding eminent domain and the potential disruption to their ability to utilize their land. Significant opposition also was derived from concern about the potential for CO_2 leaks and other environmental impacts. Navigator has not clarified if and when these permits will be reconsidered.

6.2 Wolf Carbon

Wolf Carbon Solutions abandoned plans to construct the 95-mile segment of their pipeline across eastern Iowa, per a December 2024 filing with the Iowa Utilities Commission.[47] Wolf Carbon Solutions indicates the decision may not be permanent, with activities potentially restarted pending resolution of uncertainties.

The rational for abandoning the permits is the same as for Navigator - impact of eminent domain on private property rights and owners concern for public health. The concern for public safety was also highlighted as an issue by the Illinois Commerce Commission.

6.3 Summit Carbon

Summit as of July 2025 remains the only presently active developer of a CO_2 pipeline. Figure 6-1 presents the proposed routing for the Summit Carbon pipeline within the five affected states.[48]

The Summit Carbon project experienced continued delays and regulatory hurdles, particularly in South Dakota. Iowa and North Dakota issued permits in August and November of 2024, respectively, and Minnesota issued approval in December 2024.[49] The company is still seeking permit approval in South Dakota and faces legal challenges in several states

[44] https://www.reuters.com/sustainability/climate-energy/navigator-co2-ventures-cancels-carbon-capture-pipeline-project-us-midwest-2023-10-20/
[45] https://www.reuters.com/article/business/energy/south-dakota-regulator-rejects-navigator-co2-ventures-carbon-pipeline-applicatio-idUSKBN30D18N/
[46] https://www.reuters.com/sustainability/navigator-co2-ventures-asks-iowa-pause-ccs-pipeline-permit-process-2023-10-02/
[47] https://carbonherald.com/wolf-carbon-solutions-abandons-carbon-pipeline-plans-in-iowa/
[48] https://www.desmoinesregister.com/story/money/business/2024/06/27/summit-carbon-pipeline-map-iowa-utilities-board-what-is-a-carbon-pipeline/74216858007/
[49] https://carbonherald.com/summit-gets-the-green-light-for-carbon-capture-pipeline-in-minnesota/

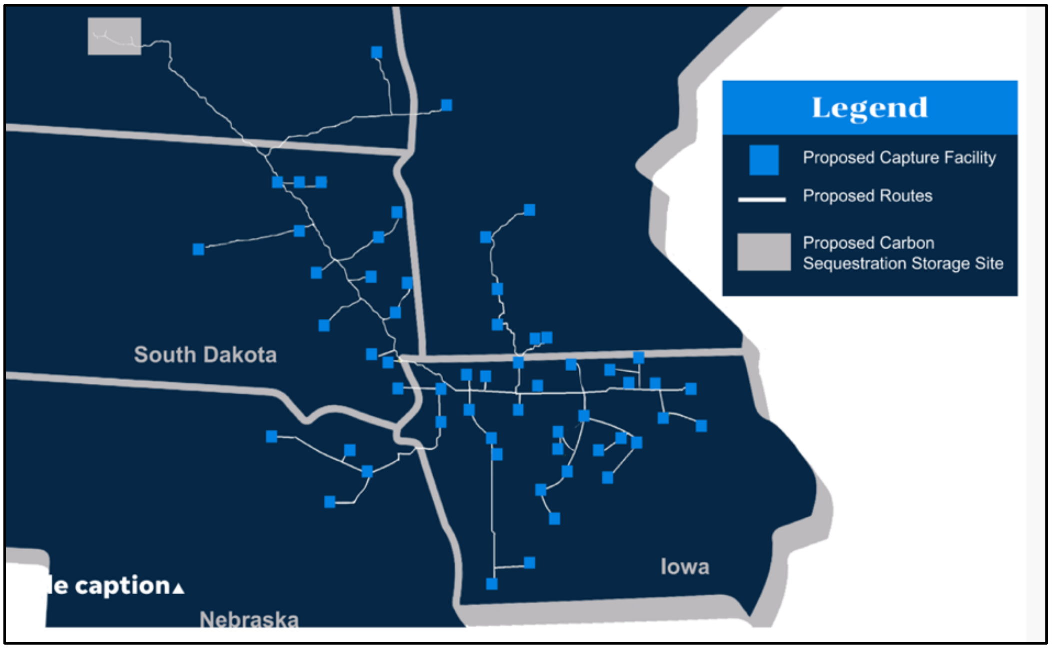


Figure 6-1. Proposed Summit CO_2 Pipeline Routing: Five States

In South Dakota, after an initial application was rejected, Summit reapplied after altering pipeline routing to minimize barriers. Despite this change, the South Dakota Public Utility Commission voted 2-1 to reject the revised route proposed.[50] A key factor is a new state law addressing eminent domain. Summit plans to alter the pipeline routing again, abandoning the most challenging elements of the route and negotiating directly with individual landowners on the most essential aspects of the pipeline.

Summit also faced legal challenges regarding the pipeline's classification as a "common carrier" which enhances the ability to invoke eminent domain to acquire land.

Conclusion. Resistance to CO_2 pipelines proposed by Navigator and Wolf Carbon has forced, at least for now, reconsideration of these projects, despite the projected benefits to the local economy of supporting the ethanol-based production facilities in these states. It is possible that any change in the 45Q tax provisions will further erode the feasibility of these projects.

Only Summit Carbon Solutions remains an entity that, at present, with permits from 4 states in hand, continues to pursue CO_2 pipelines.

[50] https://carbonherald.com/south-dakota-regulators-block-summits-8-9b-carbon-capture-pipeline/#:~:text=Summit%2C%20which%20has%20already%20invested%20more%20than,would%20refile%20with%20a%20revised%2C%20smaller%20route.

Attachment 2

Analysis of Combustion Turbine CO_2 Emission Rates
Under the 2024 Greenhouse Gas (GHG) New Source Performance Standards (NSPS)
for Fossil-Fired EGUs

Prepared for:

American Public Power Association
Midwest Ozone Group
Power Generators Air Coalition

Prepared by

J. Edward Cichanowicz
Saratoga, CA

Michael Hein
Hein Analytics, LLC
Whitefish, MT

August 4, 2025

Table of Contents

List of Figures

List of Tables

Section 1 Introduction and Summary

On June 17, 2025, the Environmental Protection Agency (EPA or Agency) issued its proposed *Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units* rule.[1] The Proposed Rule, under its primary approach, seeks to repeal all greenhouse gas (GHG) emission standards for fossil-fueled power plants. EPA is also proposing, as an alternative, to repeal a narrower set of requirements. However, among other items under the alternative approach, the Agency is not proposing to revise the "Phase 1" carbon dioxide (CO_2) new source performance standards for stationary combustion turbines (CTs).[2] Rather, the Agency is soliciting comments on the best system of emission reduction (BSER) or standards of performance and related requirements for new and reconstructed intermediate load and low load fossil-fired stationary combustion turbines (Alternative Proposal C-13 and C-14, respectively). The current Phase 1 performance standards are based on a 12-month rolling average rate in pounds of CO_2 per megawatt hour (lbs/MWh), the specific values of which depend on (1) the 12-month capacity factor (i.e., low, intermediate, and base load) and (2) fuel. This analysis examines CO_2 rates for natural gas-fired simple-cycle CTs (in the intermediate load category) and combined-cycle CTs (in the base load category). Similar concepts would apply to other fuels, including diesel oil.

This report provides comments (in response to Alternative Proposal C-13 and C-14) based on publicly available information, including the current rule issued May 4, 2024[3] and the associated rulemaking docket.

A review of this material shows EPA's methodology for selecting Phase 1 standards for simple cycle and combined cycle CO_2 emission rates is flawed, as is the economic evaluation upon which EPA relied to draw the line for base load units (which EPA assumes are always combined-cycle units) at an annual capacity factor of 40%.

First, EPA does not account for how combustion turbine design variants affect CO_2 emission rate in the selection of an appropriate standard. Although EPA recognizes the different turbine designs – such as the E-, F-, H-, and J-Class and aeroderivative variants – the Agency does not consider such differences in selecting the CO_2 emission rate. The inherent emission rate differences between these various designs can be estimated, initially, by comparing the performance specifications of the combustion turbine suppliers (i.e., thermal efficiency—and therefore CO_2 emission rates—at high load under ISO[4] conditions), adjusted to account for the impact of a real world environment of non-ISO conditions; duty cycle; component degradation;

---

[1] 90 Fed. Reg. 25,752 (June 17, 2025) (Proposed Rule).
[2] More specifically, the current rule contains efficiency-based standards of performance for intermediate load CTs and as "Phase 1" standards for base load CTs. This report refers to both as the "Phase 1" performance standards.
[3] 89 Fed. Reg. 39,798 (May 9, 2024).
[4] ISO (International Organization for Standardization) conditions for testing combustion turbines are 15° C, 60% relative humidity, and sea level elevation.

ambient temperature; etc.[5] This analysis estimates both a "mean" and maximum" adjustment to apply to the high-load, ISO thermal efficiency specified by the supplier, and finds the median adjustments of 13-16% and maximum adjustments of approximately 22-24% comport with actual data measured for different turbine design categories.

Second, reviewing CO_2 emissions obtained from the EPA Air Markets Program Data (AMD) and the specific CTs show that complying with the present CO_2 emission rates is not based on broadly available technology. Specifically, many simple cycle CTs operating between 20% and 40% capacity factor are challenged to meet the emission rate of 1,170 lbs/MWh, as it is derived from an unrepresentative subset of units. Similarly, the present limit for CTs in combined cycle and at base load of 800 lbs/MWh (up to 900 lbs/MWh for small units) is not based on broad industry practice or available options. Specifically, for simple cycle CTs, the CO_2 emission rate is based on the aeroderivative class, despite EPA intending this rate to be applicable to frame turbines designed to generate seven times more power. EPA cites three aeroderivative turbine designs by supplier and model – two reflecting the very best thermal performance by any simple-cycle CT – and effectively requires that all units in the population (even those seven times larger, with very different designs) meet the same limit. There are many differences in the design attributes of aeroderivative turbines that distinguish them from large frame units that cannot be "scaled" to larger sizes. Most noteworthy, EPA does not recognize that aeroderivative units (which are typically small) can employ air compressors that create combustor inlet pressures up to 45 times that of the ambient air, elevating thermal efficiency by 2-3 percentage points above that achievable by frame turbines of intermediate generating capacity (150-350 MW). The broad population of simple cycle turbines cannot achieve such thermal performance. The net result of the current intermediate-load standard is largely to prohibit the construction of some aeroderivative CTs and most E-, F-, H-, and J-Class frame CTs (except perhaps the very largest H-Class units) for intermediate load duty.

Regarding combined cycle applications, EPA notes the actual CO_2 emission rate of the population ranges from 720 to 920 lbs/MWh, averaging 810 lbs/MWh. EPA implements so-called "adjustments" to the CO_2 emissions from these plants, correcting for different arrangement of combustion turbines and steam turbines. These adjustments range from accounting for a 1% advantage for a 2x1 arrangement compared to a 1x1 arrangement, a 1.4% advantage of wet versus dry cooling towers, and estimating any emissions increase observed at 40% duty cycle.[6] After these corrections, EPA then reverts to identifying the Dresden Plant in Ohio as a "best-performing" unit, emitting 770 lbs/MWh, enabled in part by the use of a wet cooling tower for which obtaining a permit in the present environment is challenging. EPA

[5] Gas Turbine World 2025 Performance Specs. Hereafter GTW 2025. https://gasturbineworld.zinioapps.com/reader/readsvg/658297/Cover. Note that CO2 emission rates are a direct function of a CT's thermal efficiency, or heat rate. This report uses a conversion factor of 117 lb CO_2 lb/MMBtu.

[6] As EPA uses the term, "'duty cycle' is the ratio of the gross amount of electricity generated relative to the amount that could be potentially generated if the unit operated at its nameplate capacity during every hour of operation. Duty cycle is thereby an indication of the amount of cycling or load following a unit experiences (higher duty cycles indicate less cycling, *i.e.,* more time at nameplate capacity when operating). Duty cycle is different from capacity factor, as the latter also quantifies the amount that the unit spends offline." 89 Fed. Reg. at 39,853 n.359.

concludes the revised database and experience from Dresden justify a CO_2 emission rate of 800 lbs/MWh rate. In doing so, EPA does not explain why any unit that does not use the specific design of the Dresden CTs, that is subject to different ambient or operating conditions than Dresden, and that is operated differently than Dresden (for example, experiencing more startup and shutdown cycles, more frequent load changes, or operation at a lower operating factor) can meet the selected standard.

Finally, EPA in the 2024 rulemaking employed a 2023 NETL study[7] to create numerous reference cases to justify 40% capacity factor as the intermediate load threshold. An overarching concern is that such "static" studies do not always reflect the present marketplace, and can be misleading. In other words, the results of EPA's own study could be very different in the future, if natural gas prices change, for example, or for a number of other reasons. Separate from that concern, EPA had to create four "new" reference cases to support its position by implementing numerous extrapolations and adjustments to the NETL reference cases, almost all of which introduce significant error. These "new" reference cases created by EPA compare the levelized cost of electricity (LCOE) from a simple and combined cycle unit. Results show these units generate equivalent LCOE at 40% capacity factor – but just barely, and likely not supported by the margin of error, as differences range from negligible to 2%. Based on the trends in LCOE extrapolated from the NETL study, EPA established a yearly capacity factor of 40% as the cutoff between intermediate load and base load categories, in effect mandating that any new simple-cycle CT is prohibited from operating at a capacity factor higher than 40%.

This analysis presents an alternative approach to analyzing LCOE at different capacity factors, using a more recent Energy Information Administration (EIA) study.[8] This approach requires only a modest extrapolation to create one "new" reference case. The sole extrapolation scales capital cost and operating variables of a 650 MW combined cycle to 450 MW – well within the range of generally accepted scaling criteria. No other adjustments or extrapolations are required. These EIA-derived results show that for conditions of unit lifetime, scaling factor for capital cost, and natural gas price only slightly different from EPA's but equally reasonable, simple cycle and combined units generate at equal LCOE at greater than 50% capacity factor. Consequently, the use of 40% capacity factor as the threshold for practically requiring a combined-cycle configuration is not justified.

After this introductory section, four additional sections comprise this report. Section 2 presents the results of calculations using suppliers' specified heat rates, adjusted based on an industry observer data to reflect real-world duty. Section 3 presents actual results from the AMD as evaluated by EPA, and independently by this study. Section 4 identifies how EPA established the basis for the proposed CO_2 emission rate limits for simple and combined cycle CTs. Section 5 critiques EPA's economic study used to justify the 40% capacity factor threshold for base load operations and performance standards (i.e., simple-cycle prohibition), and introduces an alternative approach.

[7] Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, National Energy Technology Laboratory, May 2023.
[8] Energy Information Agency, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, January 2024.

Section 2. Combustion Turbine Supplier Performance Specification

Introduction

Section 2 provides background information that demonstrates how the design of a combustion turbine (CT) fundamentally determines the CO_2 emission rate per MWh of output for any particular CT. The thermal efficiency of the combustion turbine drives the CO_2 emission rate of a CT. Each CT has an inherent thermal efficiency, typically expressed in terms of British Thermal Unit (Btu) per kilowatt-hour of output (Btu/kWh). This metric is also referred to as heat rate, typically specified by the manufacturer at full-load, under ISO conditions. At any given point in time, however, the thermal efficiency of the CT is affected by a multitude of factors, among them: (1) the operating load; (2) degradation (both unrecoverable and between maintenance cycles); (3) altitude; (4) ambient temperature; and (5) design margin. Simple-cycle CTs are also affected by inlet/outlet pressure losses, while combined-cycle CTs are also affected by air inlet fouling and steam condenser conditions.

This discussion provides key background information describing how the five major categories of combustion turbine design – aeroderivative and four "frame" classifications – compare. The analysis starts with suppliers' performance specifications for commonly deployed combustion turbines in both simple and combined cycle, operating at ISO, full load conditions. These data are subjected to two comparisons. First, these theoretical (specification) performance metrics are adjusted to reflect real-world operation due to changes in load, ambient temperature and elevation, component wear, inlet compressor fouling, and other factors. These adjustments are implemented based on experience assimilated by the industry trade publication, the *Gas Turbine World 2025 Performance Specs* report, and a technical paper by a supplier. Second, the adjusted performance specifications are compared to CO_2 emissions as calculated from EPA Air Markets Program Data (AMD)[9] for commercially operating units, per turbine frame design.

Combustion Turbine Population

The *Gas Turbine World 2025 Performance Specs* report describes performance data for the population of combustion turbines generating 25 MW or more and operating at 60 Hz.[10] The report introduces adjustment factors addressing the impact of operating load, startup and shutdown, ambient temperature, site elevation, component wear, and other factors. The authors note these adjustment factors should not be used to base a design or component selection, but to

[9] Strictly speaking, CO_2 is not directly measured but determined from assumed heat content, fuel flow and EPA's CO_2 emission factor for natural gas (i.e., 117 lb CO_2/MMBtu for pipeline-quality natural gas).
[10] GTW 2025. https://gasturbineworld.zinioapps.com/reader/readsvg/658297/Cover.

provide insight that should be validated by contact with the supplier, or further study.[11] Additional insight into the role of several of factors is also provided by publications in the trade press[12] and by a supplier of combustion turbines.[13] This evaluation uses the *Gas Turbine World 2025 Performance Specs* adjustments to provide insights into the likely ability of various CT models currently available on the market to meet the 2024 Phase 1 standards, assuming their operation and other conditions are within the experience reflected in these publications.

For the purposes of this evaluation, a subset of combustion turbines consisting of 27 units in simple cycle mode is considered from four suppliers. Table A-1 in Appendix A provides the suppliers' specification for generating capacity and heat rate for these units. A total of 22 of these same combustion turbines are arranged by their suppliers in a combined cycle mode, representing over 40 different generating units. Table A-2 summarize these units according to various arrangements with heat recovery steam generators (HRSG) and steam turbines. For example, combustion turbines can be configured in a "1 x 1" arrangement (e.g. 1 combustion turbine, HRSG, and steam turbine) or a "2 x 1" arrangement with two combustion turbines/HRSGs and one steam turbine. Appendix A also includes several "3 x 1" arrangements.

The CO_2 emission rate is calculated from the supplier specification, per usual practice reported in terms of Lower Heating Value (LHV) of the fuel. EPA's CO_2 performance standards, however, are based on fuel carbon content per Higher Heating Value (HHV). Consequently, this analysis will (a) employ a fuel carbon content of 117 lbs/MBtu HHV,[14] and (b) adjust the heat rate specified by suppliers by a nominal 11% to account for the difference in natural gas HHV versus LHV. Using the CO_2 content of natural gas, CO_2 emission rates from simple and combined cycle units are calculated under the specified conditions (ISO, full load, new and clean surfaces, and no component wear).

Operating Factors

The CO_2 emission rate is calculated using supplier specification (as discussed above) and adjusted to reflect real-world operating conditions, as reported in the *Gas Turbine World 2025 Performance Specs* and a technical paper by a supplier.[15] These adjustments are summarized in Table 2-1 for simple cycle[16] and Table 2-2 for combined cycle.[17]

---

[11] Ibid. For example, regarding the role of operating load on unit heat rate, the authors note the following on page 7. The curves presented here are intended only for instructive and preliminary estimating purposes. When appropriate in your studies, contact OEMs for a complete and accurate analysis…".
[12] The role of ambient temperature and altitude also described in literature: https://www.power-eng.com/operations-maintenance/why-keeping-cool-keeps-output-high/
[13] Advanced Technology Combined Cycles, GE Power Systems, GER3936A. Hereafter GE3936A.
[14] Small changes in natural gas carbon will change CO_2 generation rate. EPA assumes a fixed carbon content from natural gas and 100% conversion to CO_2 to establish the carbon balance for Part 75 calculations. Natural gas carbon content is affected by the content of higher carbon constituents and lower hydrogen-content constituents such as pentane, can alters CO_2 generation rate per MBtu.
[15] GE3936A
[16] GTW 2025. At 7.
[17] Ibid. At 18.

Table 2-1. Simple Cycle "Real World" Heat Rate Impacts: Operating Factors

Factor	Heat Rate Impact	Mean Impact (%)	Maximum Impact (%)
Operating Load (fraction of capacity)	4% increase in heat rate at 80% load[18]	3.5	8
Degradation	2-6% loss in 24,000 hrs; restorable to within 1-1.5% of design	4	6
Altitude[19]	3.5% loss in power = each 1,000 ft above sea level		
Ambient temperature	0.1% increase in heat rate = each 1ºF above ISO	0.5	1.6
Inlet/Outlet losses per incurred air or gas pressure drop	0.2% increase in heat rate with each 1 inch w.g. increase in inlet/output pressure drop	0.8	1.6
Design Margin	3-5%	4	5
Total		12.8	22.2

Table 2-2. Combined Cycle "Real World" Heat Rate Impacts: Operating Factors

Factor	Impact	Mean Impact (%)	Maximum Impact (%)
Operating Load (fraction of capacity)	4% increase in heat rate per cycling, frequent startup/shutdown.	4	6
Degradation	3-5% loss in 10-15 Years	4	5
Altitude	0.2% increase in heat rate = each 1,000 ft above sea level	0	1.2
Ambient temperature	0.5% higher heat rate = per 10ºF above ISO	0.25	0.8
Air Inlet Fouling	1.2% increase in heat rate, not recoverable	1.2	1.8
Condenser (Heat Removal)	1% increase in heat rate per 0.5-inch Hg absolute pressure[20]	2 (per 1.0 in Hg	4 (per 2 in Hg
Design Margin	3-5%	4	5
Total		15.5	23.8

[18] GE3936A. Figure 3.
[19] Altitude results in a loss of maximum power output for a simple cycle combustion turbine, as reported above. It is unclear whether altitude also affects heat rate. This evaluation assumes no impact on heat rate from altitude.
[20] Ibid. Table 1 describes "new and clean" as 1.2 in Hg absolute; means and maximum impact values assumed as 1 and 2 in Hg absolute, respectively.

Table 2-1 summarizes the detrimental effects on heat rate for simple cycle combustion turbines due to five operating factors. These include operating load, component degradation, host site altitude, annual ambient temperature, and combustion air intake pressure drop. For each of these operating factors, the range cited in the *Gas Turbine World 2025 Performance Specs* augmented with a combustion turbine supplier's paper is reported. Two example cases are defined, reflecting "mean" conditions based on intermediate or mean values of the ranges listed in Table 2-1, and a "maximum" case based on the highest values in the range. The mean values of the heat rate detriment assigned are 3.5% for part load operation and startup/shutdown, 4% for component degradation, 0.5% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), and 0.8% for a total of 4 in w.g. inlet air pressure loss. Including an additional 4% compliance margin (intermediate to the 3-5% design margin offered by GE in comments submitted in 2024).[21] In total, a mean total detriment of 12.8% is estimated.

The maximum values observed are 8% for part load operation and startup/shutdown, a 6% for component degradation, 1.6% to reflect units with ambient temperature elevated by 20ºF (e.g. from 59 to 79ºF), and 1.6% for a total of 4 in w.g. inlet air pressure loss. Per GE recommendations, the additional design margin of 5% is assigned, resulting in a total 22.2% detriment. (An additional compliance margin is not included in these example cases).

Table 2-2 similarly summarizes the detriment to heat rate for combined cycle combustion turbines due to operating factors analogous to simple cycle, but accounting for steam cycle heat rejection. These include operating load, component degradation, host site altitude, annual ambient temperature, combustion air intake pressure loss, and fouling of the condenser dedicated to heat rejection. The cumulative detriment to heat rate based on the mean values in Table 2-2 is 4% for part load and startup/shutdown operation, 4% for component degradation, 0.25% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), 1.2% for inlet air fouling pressure loss, and an additional 2% to account for a 1 inch Hg absolute penalty in steam cycle condenser pressure drop. Including an additional 4% design margin (intermediate to the GE report of 3-5%) a total detriment of 15.5% is estimated.[22]

For the maximum values in Table 2-2, the cumulative detriment is 6% for part load and startup/shutdown operation, 5% for component degradation, 1.2% to reflect a unit at 6,000 feet of altitude, 0.8% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), 1.8 % to reflect inlet air fouling loss, 4% to account for a 2-inch Hg absolute steam cycle condenser pressure loss. The maximum margin of 5% as advised by GE is also included, resulting in a total 23.8% detriment.

---

[21] GE Verona Comments, Docket No. EPA-HQ-OAR-2023-0072. At 48. Hereafter GE 2023 Comments.
[22] The role of operating factors on CO_2 emission rate, as documented by the *Gas Turbine World 2025 Performance Spec* and summarized in Tables 2-1 and 2-2, demonstrates CO_2 emission rate from any CT is determined not only by design but also by operating factors - many out of control of the operator. By basing the standards on the performance of certain units operating under specific operating factors (without accounting for the variability of factors outside the control of the operator or how operators may use their units differently elsewhere or in the future), EPA essentially incorporated these factors into its Best System of Emission Reduction (BSER) determination. This is inconsistent with the historical methodology, which depends primarily on process equipment design and performance, not restrictions on equipment operating factors.

CO_2 Emission Rates: As Calculated

The combustion turbine performance specifications and adjustments to heat rate due to operating factors, as defined in Tables 2-1 and 2-2, are used to calculate the CO_2 emission rate. These calculations are presented in Figures 2-1 and 2-2 for simple and combined cycle, respectively.

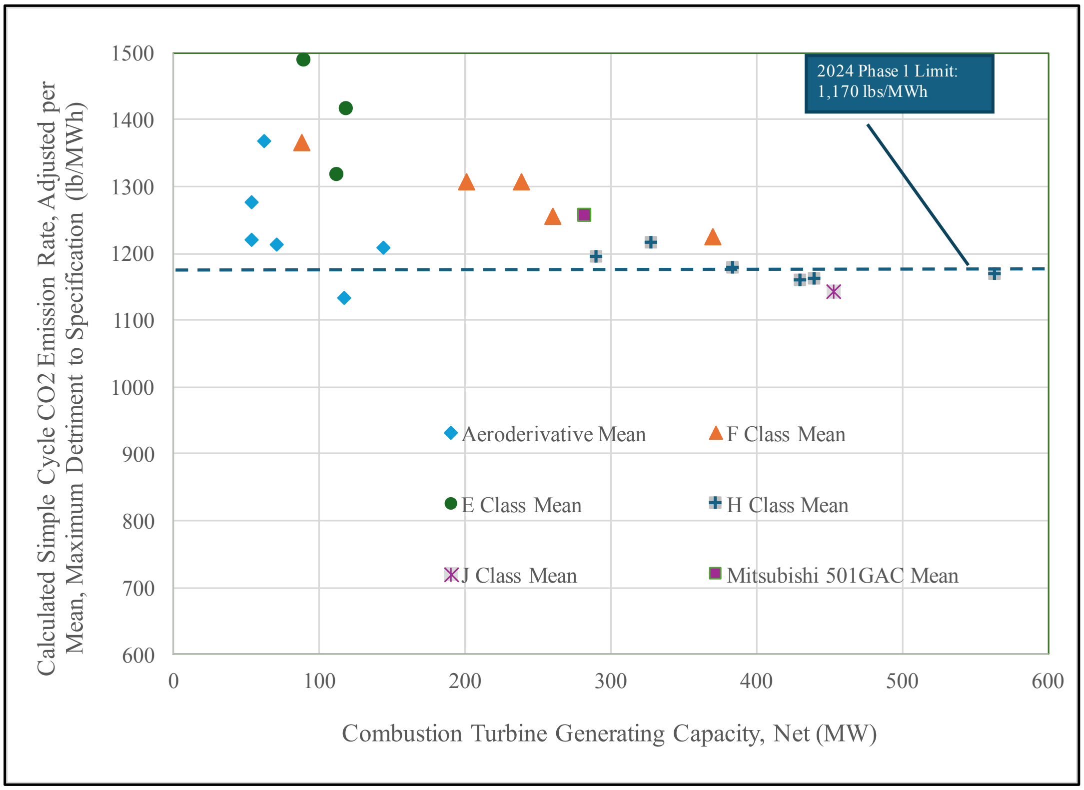


Figure 2-1. Calculated CO_2 Emission Rate: Simple Cycle

Simple Cycle

Figure 2-1 reflects the calculated CO_2 emission rate for the various combustion turbine designs designated in Appendix Table A-1. The mean value as determined from Table 2-1 is presented for each turbine classification, with data from each turbine class represented by the same marker and color. Figure 2-1 shows that based on the suppliers' specification and Gas Turbine World adjustments, a limited number of large H-Class, J-Class, and aeroderivative CTs, with the mean adjustment values are theoretically expected to have lower CO_2 rates than the current Phase 1 CO_2 emission standard of 1,170 lbs/MWh. However, no simple cycle CT with maximum adjustment (data not plotted for simplicity) can, even theoretically, meet the limit. A notable number of designs – in particular E-Class and F-Class models, and most aeroderivative designs – have specification CO_2 emissions rates adjusted by the mean value equal to or exceeding the 2024 Phase 1 CO_2 standard of 1,170 lb/MWh.

As a result, it appears that the 2024 Phase 1 CO_2 emission standard of 1,170 has the effect of prohibiting the use of a significant number of CT designs – several aeroderivative; all E-Class and F-Class, and most H-Class – as simple-cycle CTs operating at intermediate load. These types of units are, effectively, relegated to low-load duty under the current rules.

Combined Cycle

The Figure 2-2 combined cycle CO_2 emission rates reveal a pattern like that for simple cycle CTs – some of the largest H-Class and J-Class units can theoretically emit at less than the CO_2 emission standard of 800 lbs/MWh for the mean adjustment to heat rate. Those CTs would have a very small compliance margin. All other CT designs would likely exceed the standard, even at mean adjustment. The calculated CO_2 emission rates using the maximum adjustment (data not plotted for simplicity) of all currently available CTs would exceed 800 lb/MWh. None of the E-Class or aeroderivative design combined cycle units can meet the 2024 Phase 1 standard for base load units (which increases to 900 lb/MWh for units with heat input less than 2,000 MMBtu/h), for either the mean or the maximum.

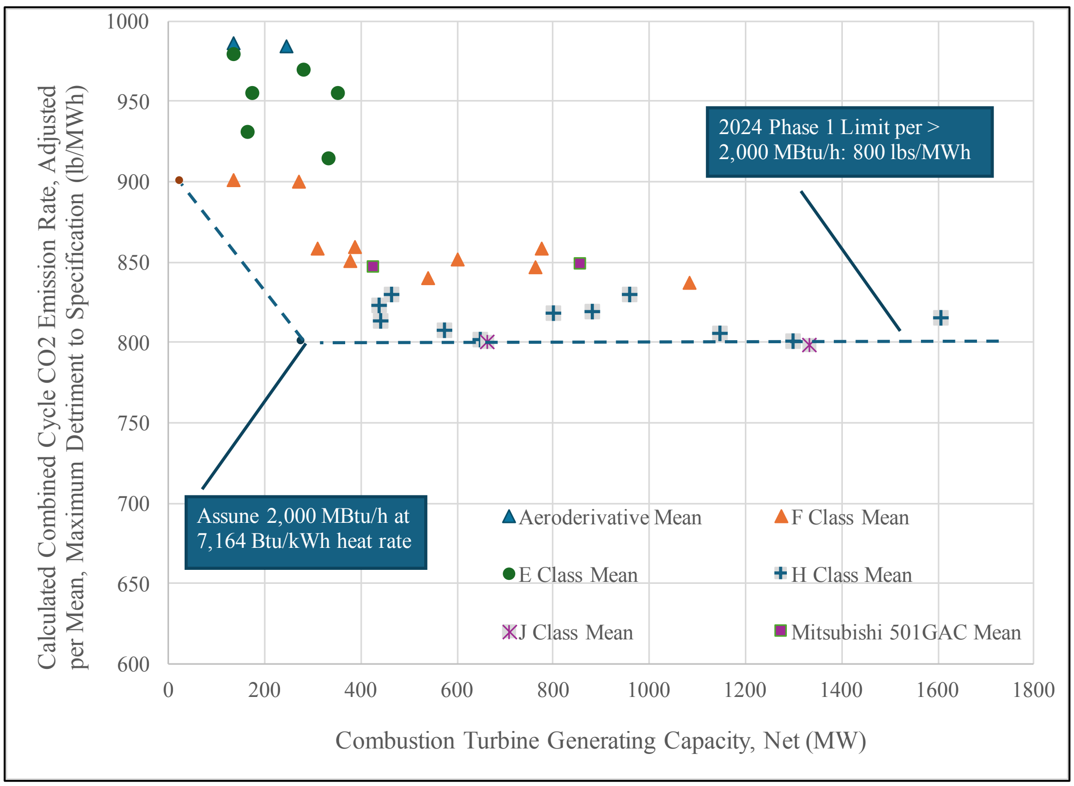


Figure 2-2. Calculated CO_2 Emission Rate: Combined Cycle

Reported Data

Reported actual CO_2 emission rates for combustion turbines is the third and possibly most significant comparison. Sections 3 and 4 of this report address data acquired from the EPA's AMD for two databases of populations of combustion turbines in the U.S. - one defined and used by EPA, and a second larger database used by this study. Prior to the Section 3 and 4 discussion of CO_2 emission rate trends with various operating factors, it is instructive to compare simple averages of CO_2 emission from the five design categories of turbine classes to those presented in

Figures 2-1 and 2-2. The results enable inferring an actual margin to compare with the observations offered by the *Gas Turbine World* and a supplier.

Both the EPA and this study considered simple and combined cycle units that commenced duty in 2015. Both the EPA and this study derived a database of reference units, which are screened to identify those simple cycle units operating at a minimum 12-month rolling capacity factor of 20%. EPA's database includes 87 simple cycle units of which 15 operated at 20% or more capacity factor, and 59 combined cycle units.[23] This study evaluated 146 simple cycle units of which 23 have operated at 20% capacity factor or more; and 72 combined cycle units. A further description of the differences in the databases is presented in Section 4. For both databases, the maximum CO_2 emission rate is determined over a 12-month rolling average.

The sources of data are as follows:

- Study Population: Commercial Service 2015-2023 natural gas-fired turbines CO_2 *Emission Rate = Sum of 2023-2024 CO_2 Mass (tons) divided by Sum of 2023-2024 Gross Load (MWh)*
- EPA Air Market Program Data: 2015 through 2023, Annual Basis
- EIA-860 – Unit Configuration, Size, Cooling Type, In-Service Date, Latitude/Longitude
- Capacity and Operating Factors: Same Basis
- Elevation Data: "Open Elevation" by lat/long
- Weather Data: "OpenMeteo" – annual, daily, hourly by latitude/longitude

The combustion turbine design category is not defined in these databases; such design information is acquired from files in EPA's Cross State Air Pollution Rule docket,[24] and augmented by a literature search and supplier information. These sources provide CO_2 emission from four of the five classes of turbines. The CO_2 emission rate and number of turbines in each design category are summarized in Figure 2-3 and the standard deviation of those emission rates are shown in Figure 2-4. These results are described as follows.

Simple Cycle

Aeroderivative. For 24 aeroderivative turbines operating at 20% capacity factor or greater, the CO_2 emission rate averaged 1,213 lbs/MWh. This actual, "as-observed" rate implies a real-world increase of 11% over the average of the suppliers' specification (i.e., at ISO and full-load) of 1,091 lbs/MWh. This average is relatively consistent with the 12.8% mean adjustment using *Gas Turbine World* and supplier data.

[23] EPA's database does not include generating units that entered commercial service after 2020; no rational is cited. This analysis, being able to access data through 2024, could include units that operated in 2021-2023 and have adequate data to calculate at least 12 data of 12-month rolling averages. Consequently, this study was able to utilize 78 additional units (69 simple cycle, 9 combined cycle).
[24] EPA EPA-HQ-OAR-2024-0419-0020_attachment_3. Available at https://www.epa.gov/Cross-State-Air-Pollution/cross-state-air-pollution-rule-csapr-regulatory-actions-and-litigation.

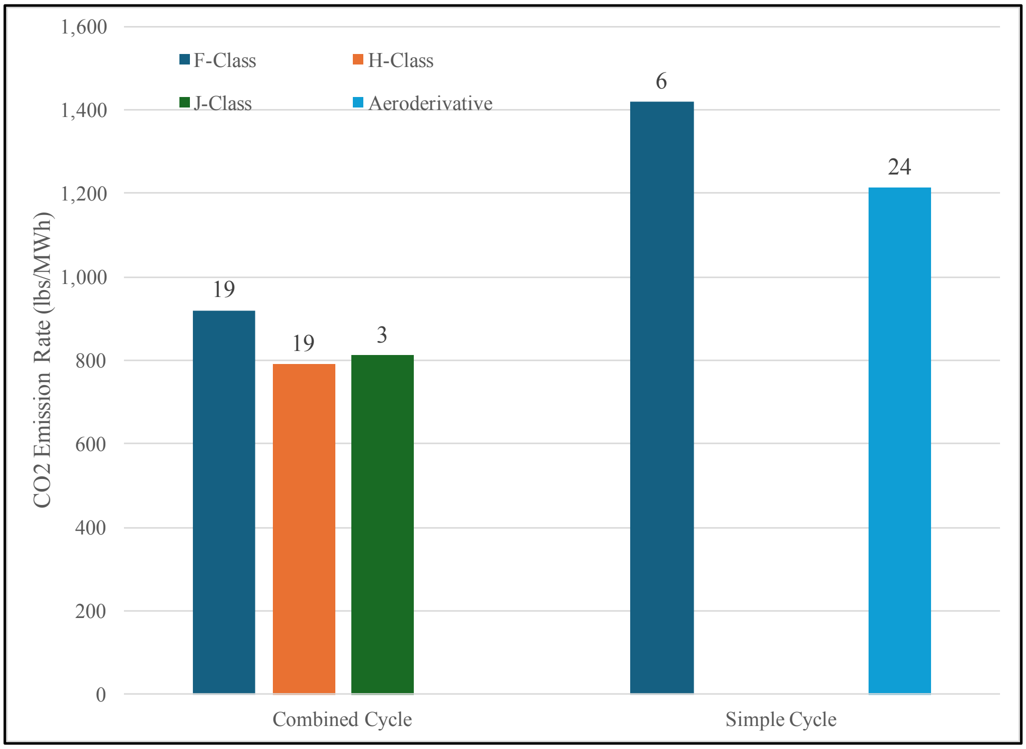


Figure 2-3. CO_2 Emission Rate from Turbine Design Categories: Simple, Combined Cycle

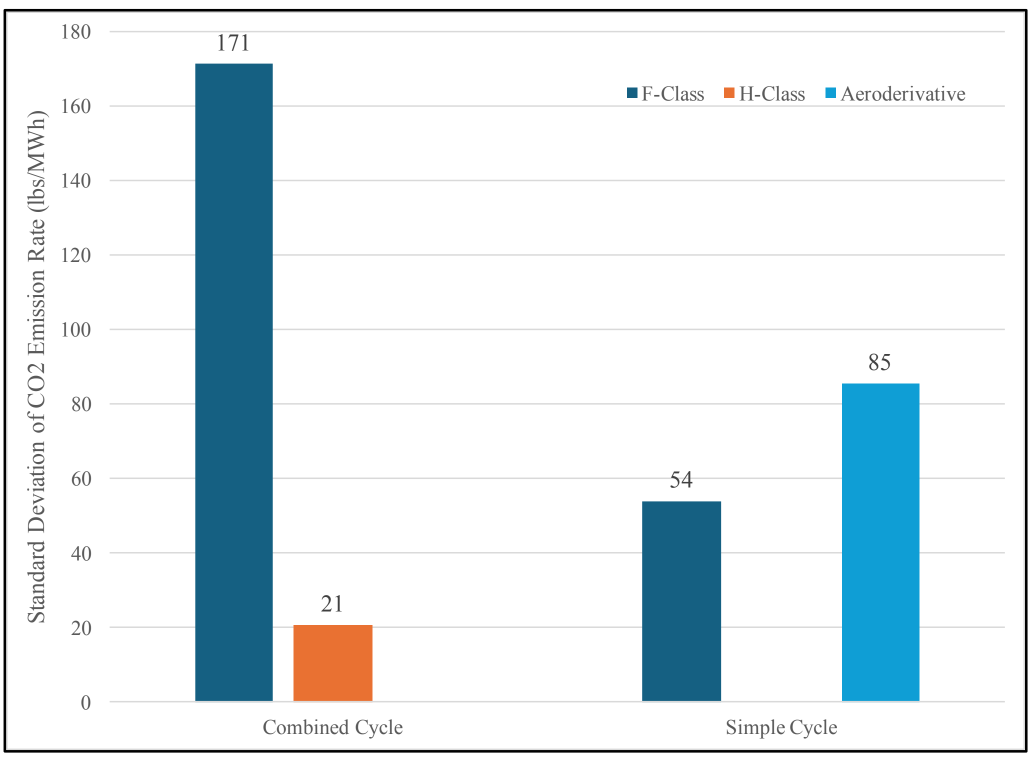


Figure 2-4 Standard Deviation of Maximum CO_2 Emission Rate per Categories: Simple, Combined Cycle

It is further insightful to consider the variability of this data by reviewing the standard deviation, or the CO_2 rate which 68% of the population either exceeds or is below the mean value. Figure 2-4 shows the standard deviation for the aeroderivative class is 85 lbs/MWh; implying nominally 7 units emit CO_2 at 1,298 lbs/MWh or greater, and the same number of units emit at 1,128 lbs/MWh or lower.

F-Class. These 6 units average 1,419 lbs/MWh of CO_2 emission, implying a 24% margin over the average of the suppliers' average specifications of 1,141 lbs/MWh. This real-world increase approximates the maximum of 22.2% of adjustment using *Gas Turbine World* and supplier data. These data exhibit a standard deviation of approximately 54 lbs/MWh; implying one or two units emit up to 1,453 lbs/MWh, and one or two 1,366 lbs/MWh or less.

Combined Cycle

The combined cycle data in Figure 2-3 are determined by design variables discussed previously. These are arrangements of the combustion turbine, HRSG, and steam turbine, and the use of wet or dry cooling tower. Sections 3 and 4 describe how these design variants affect the CO_2 emission rate.

F-Class. The 19 turbines within this category average CO_2 emissions of 920 lbs/MWh. The implied real-world increase for this category is 24% over the average specifications of 745 lbs/MWh, approximating the maximum adjustment of 23.8% using Gas Turbine World and supplier data. These data exhibit a relatively high standard deviation of 171 lbs/MWh, implying approximately 6 units emit more than 1,091 lbs/MWh, and the same number emit at 751 lbs/MWh or less.

H-Class. The 19 units comprising this category average 791 lbs/MWh of CO_2 emission. Many of these units are of the larger capacity 2 x 1 or 3 x 1 arrangement, biasing the CO_2 emissions rate low.[25] Any such bias to lower CO_2 is problematic for units with arrangement of 1x1, anticipated to be the most popular configuration. These emission rates imply a real-world operating increase of 12% over the average specifications of 706 lbs/MWh, approaching the mean adjustment of 15.5% using *Gas Turbine World* and supplier data. These data exhibit a relative small standard deviation of approximately 21 lbs/MWh.

J-Class. The three units present an average of 811 lbs/MWh; similar to H-Class these CO_2 emissions rates are influenced by combustion turbine and steam turbine arrangement. A real-world operating increase of 17% is implied, exceeding the mean adjustment using *Gas Turbine World* and supplier data. This population is too small to merit a meaningful standard deviation.

[25] Another complication of bias introduced by 3x1 and 2x1 arrangements is the impact when one or more turbines are off-line for service. This resulting configuration – even if operating for 4- 8 weeks –will affect the 12-month rolling average. This possibility is a basis for considering adequate design and operating margin in selection of CO_2 emission rate.

It should be noted that the use of duct burners, to increase power generation during periods of peak demand and adopted by approximately 75% of the combined cycle inventory,[26] can significantly affect heat rate. The heat rate impact can vary widely, from less than 1% to more than 3%.[27] However, the effect on the 12-month rolling average of CO_2 emission rate is less, as duct-firing is generally used only during periods of peak power and when justified by market electricity prices – perhaps 20% of operating time.[28] The data in Figures 2-3 and 2-4 probably reflects the impact of duct firing on the performance of the units in the population analyzed, although an explicit assessment of the contribution is not addressed in this evaluation.

Observations

Observations addressing the CO_2 emission rate specified by suppliers, with adjustments recommended by an industry trade publication to reflect "mean" and "maximum" expected real-world increases, and comparison to a sample of actual CO_2 data reported under the requirements of the Acid Rain Program (40 CFR Parts 72-75) are presented as follows:

- Calculated CO_2 emission rates, based on suppliers' design specifications and accounting for real-world heat rate impacts of operating factors, as observed by an industry publication, show CO_2 emission rates from simple and combined cycle duty vary considerably with the turbine design: aeroderivative, E-, F-, J-, and H- Class turbine.

- Observed CO_2 emission rates from a total of 30 simple cycle units, as derived from the AMD, imply an average adjustment factor to apply to the suppliers full-load/ISO CO_2 emission rate to reflect real-world data. The simple cycle data in Figure 2-3 imply an adjustment by approximately 11% for aeroderivative and 24% for F-Class units to reflect real-world operating duty. There is no data in AMD for E-Class and H-Class in simple cycle configuration. However, it is expected that both of these models will be used in these configurations in the near future and beyond.

- Observed CO_2 emission rates from a total of 41 combined cycle units, as derived from the AMD, imply an average adjustment factor to apply to the suppliers full-load/ISO CO_2 emission rate to reflect real-world data. The combined cycle data in Figure 2-4 imply an adjustment from 12% to reflect H-Class duty up to 24% to reflect F-Class duty.

The implications for meeting the 2024 Phase 1 standard for intermediate load (simple cycle CTs) and base load (combined cycle CTs) are summarized as follows:

- Simple Cycle. Figure 2-1 shows only one aeroderivative and several H- and J-Class units, using the calculated CO_2 emission rates based on the mean adjustment to specified heat rate, can meet the Phase 1 limit of 1,170 lbs/MWh; notably with little or no compliance margin. The use of the mean adjustment is corroborated by real-world data.

[26] https://www.eia.gov/todayinenergy/detail.php?id=52778.
[27] The detriment to combined cycle unit heat rate due to duct burners is estimated to range from less than 1% to 3%. See https://www.power-eng.com/coal/combined-cycles-exploding-the-cookie-cutter-myth/.
[28] https://www.power-eng.com/gas/combined-cycle/advancements-in-duct-firing-technology/

- Combined Cycle. Figure 2-2 shows a limited number of F-, H-, and J-Class units can meet the CO_2 standard based of 800 lb/MWh, with little or no margin, based on suppliers' heat rate at ISO conditions and adjusted for mean detriments. The use of the mean adjustment is corroborated by real-world data.

Section 3. CO_2 Emission Rate Trends per Air Markets Program Data

Introduction

Section 3 reports trends in CO_2 emissions per MWh for both simple cycle and combined cycle units calculated from EPA's AMD. Data acquired from the AMD as used by (a) EPA to develop the 2024 Phase 1 Greenhouse Gas (GHG) New Source Performance Standards NSPS emission limits are presented, and (b) this study are both addressed. Differences in the universe of units evaluated are considered.

Both the EPA and this study derived databases of simple and combined cycle units that commenced duty in 2015 or later.[29] These databases considered all operating units, but for simple cycle only units operating at capacity factors of 20% or greater are considered in the evaluation. For combined cycle units, all but six operated at a capacity factor of 40% or greater and the units that operated at less than 40% capacity factor are excluded from the evaluation. The maximum CO_2 emission rate observed over the series of 12-month rolling averages since unit inception is calculated using the data sources listed in Section 2.

Reference Database

The database used by EPA differs from that utilized in this study. As described in Section 2, EPA's is comprised of 87 simple cycle and 59 combined cycle operating units.[30] This study identified 146 simple cycle and 69 combined cycle operating units. For simple cycle units that operate at 20% capacity factor or greater, EPA identified 17, while this study identified 23 units. Regarding combined cycle, all but six units in each database assembled by EPA and this study operated for at least one year above 40% capacity factor. Most of the difference in the population of the two databases appear to be due to a large number of units entering commercial service since 2021 that are not captured in the previous rulemaking by EPA.

Table B-1 in Appendix B lists the units in EPA's database not addressed in this study; Table B-2 lists units addressed in this study not considered by EPA.

Operating Features

Before considering the CO_2 emission rates of simple and combined cycle units, the characteristics of duty factor and operating factor are compared in Figures 3-1

[29] Units entering service in 2015 and thereafter likely reflect state-of-the-art technology, but (for the most recent of these units) may not capture the long-term role of component degradation with service time. Adequate margin in selecting CO_2 rates would address this uncertainty.
[30] EPA-HQ-OAR-2023-0072-0060_attachment_6

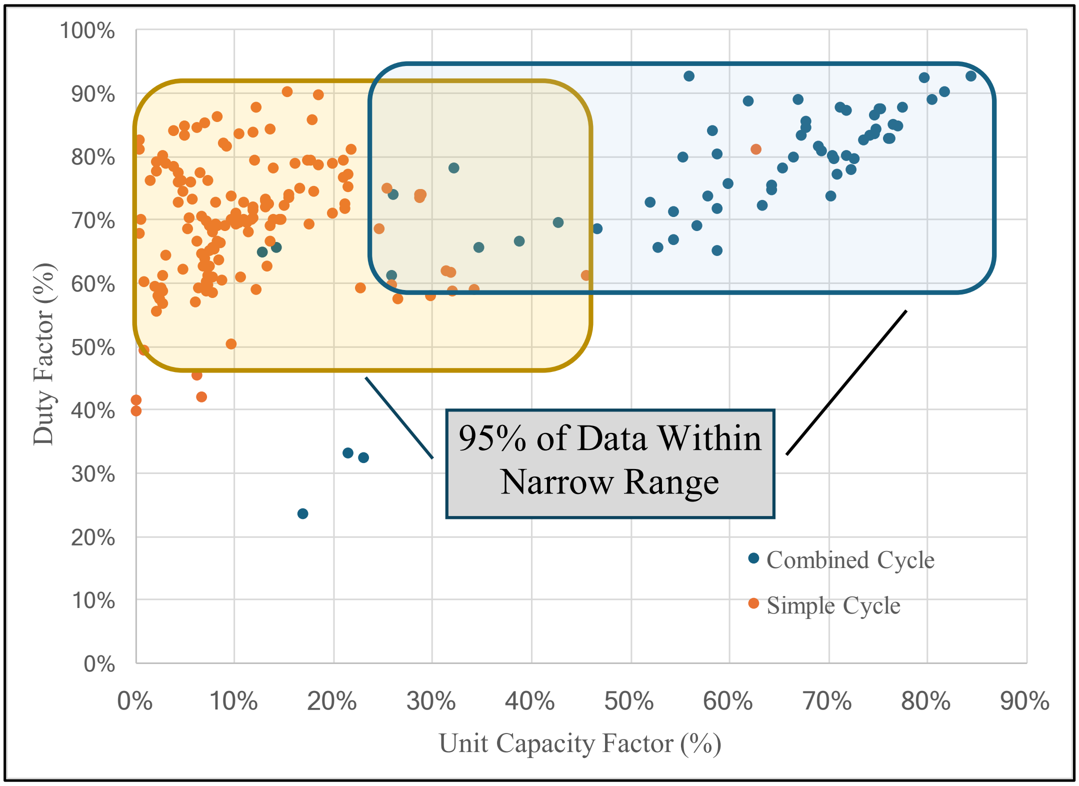


Figure 3-1. Combustion Turbine Operating Factor vs. Capacity Factor

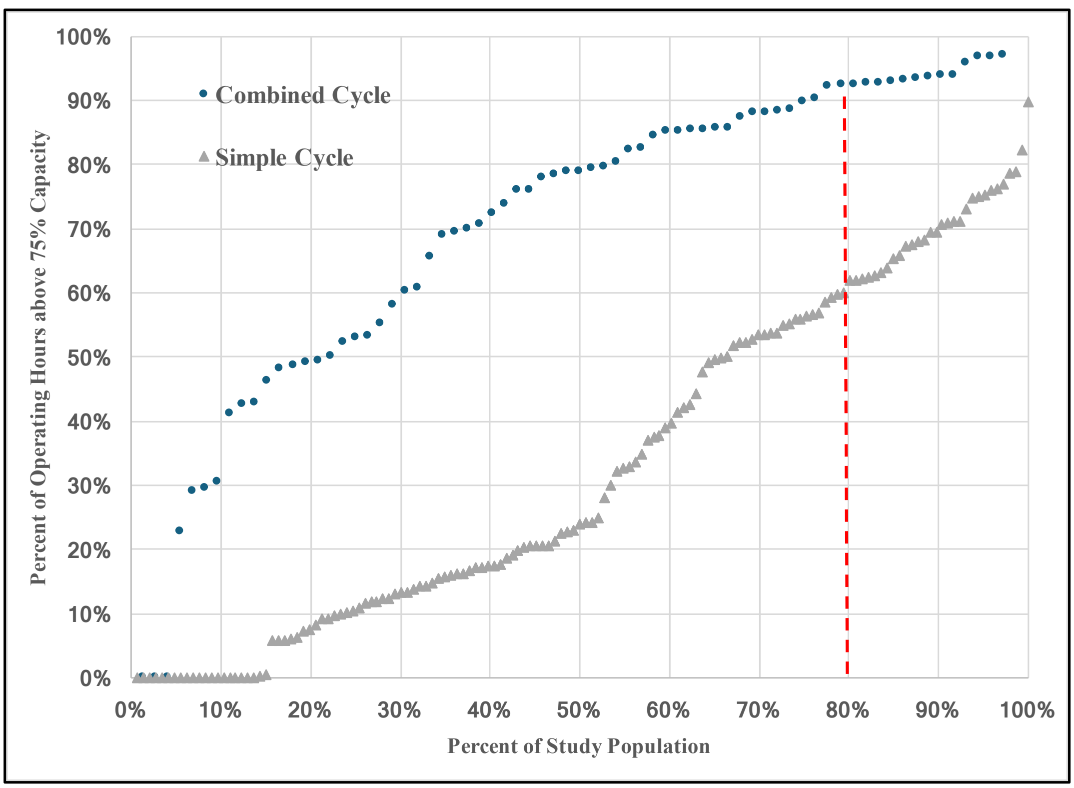


Figure 3-2. Percent Operating Hours Exceeding 75% Capacity: Simple, Combined Cycle

Figure 3-1 compares duty factor (what EPA calls duty cycle) and capacity factor for simple and combined cycle units addressed in this study, while Figure 3-2 reports the units' operations above 75% capacity factor. Figure 3-1 shows that although simple cycle units operate at much lower capacity factors than combined cycle, both types of units operate predominantly at high loads. The figure shows 95% of simple cycle units operate on average at 50 to 92% of maximum capacity (i.e., a duty factor of 50 to 92%). Combined cycle units exhibit a similar trend – 95% of units operate at an average of 58 to 94% of maximum capacity (i.e., a duty factor of 58 to 94%).

Figure 3-2 presents the cumulative frequency distribution of operating hours for simple and combined cycle units. Combined cycle units expend significant operating time at greater than 75% capacity – 80% of the units operate for 93% of the time as such. Eighty percent of the simple cycle units expend 60% of operating time at more than 75% capacity.

Additional discussion is presented according to each operating cycle as follows.

Simple Cycle

This study identified 146 simple cycle units firing natural gas from EIA and EPA sources as candidates for evaluation. Of this population, 30 units have operated between 20 and 40% capacity factor for at least one year, generating at least one relevant 12-month rolling average CO_2 emission rate. The maximum CO_2 emission rate for these 30 units over the qualifying 12-month rolling average periods is presented in Figure 3-3 as a function of unit nameplate generating capacity.

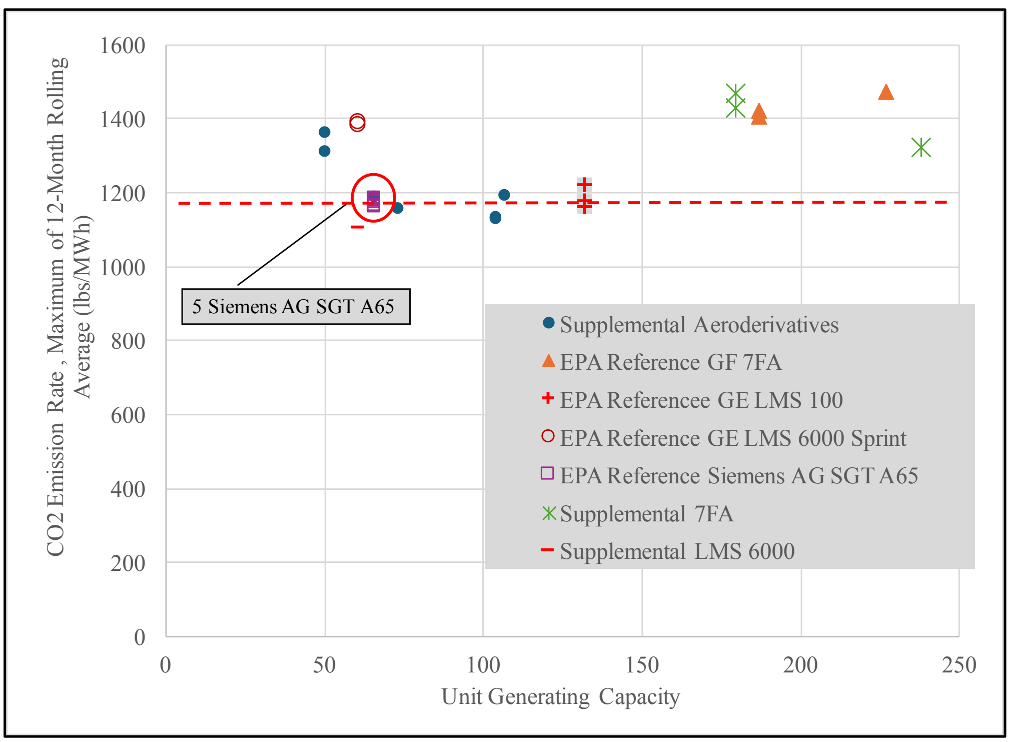


Figure 3-3. CO_2 Emissions Rate vs. Nameplate Capacity: 30 Simple Cycle Units Operating Between 20 and 40% Capacity Factor

The Figure 3-3 legend identifies data designated by EPA as references for the 2024 Phase 1 standard for simple cycle units operating at intermediate load. The legend also identifies the supplementary units introduced by this study. Notably, all of the units that can meet the intermediate load CO_2 performance standard are aeroderivative. Six of the 16 units cited by EPA are found to operate at or below the Phase 1 rate of 1,170 lbs/MWh (although 3 exceed by only 2 to 8 lbs/MWh). Three of the 14 supplemental units introduced by this study emit at less than the standard.

Combined Cycle

A total of 69 combined cycle generating units are identified from the EIA and EPA data and evaluated by this analysis. Of these, eight operated at an average 12-month capacity factor calculated over their operating years as less than 40%.

Figure 3-4 presents the maximum 12-month rolling average CO_2 emission rate (lbs/MWh) as a function of the nameplate generating capacity for units operating over 40% capacity factor. Of the 61 units in Figure 3-4, a total of 26 (42%) operated at CO_2 emissions rates that meet the 2024 Phase 1 GHG NSPS CO_2 emissions limit of 800 lbs/MWh. The average of all units in Figure 3-7 is 835 lbs/MWh. Notably, there are few combined cycle units that generate less than 250 MW capacity – and only one of a capacity of 100 MW or less. All of them emitted above the performance standard selected in the 2024 rule.

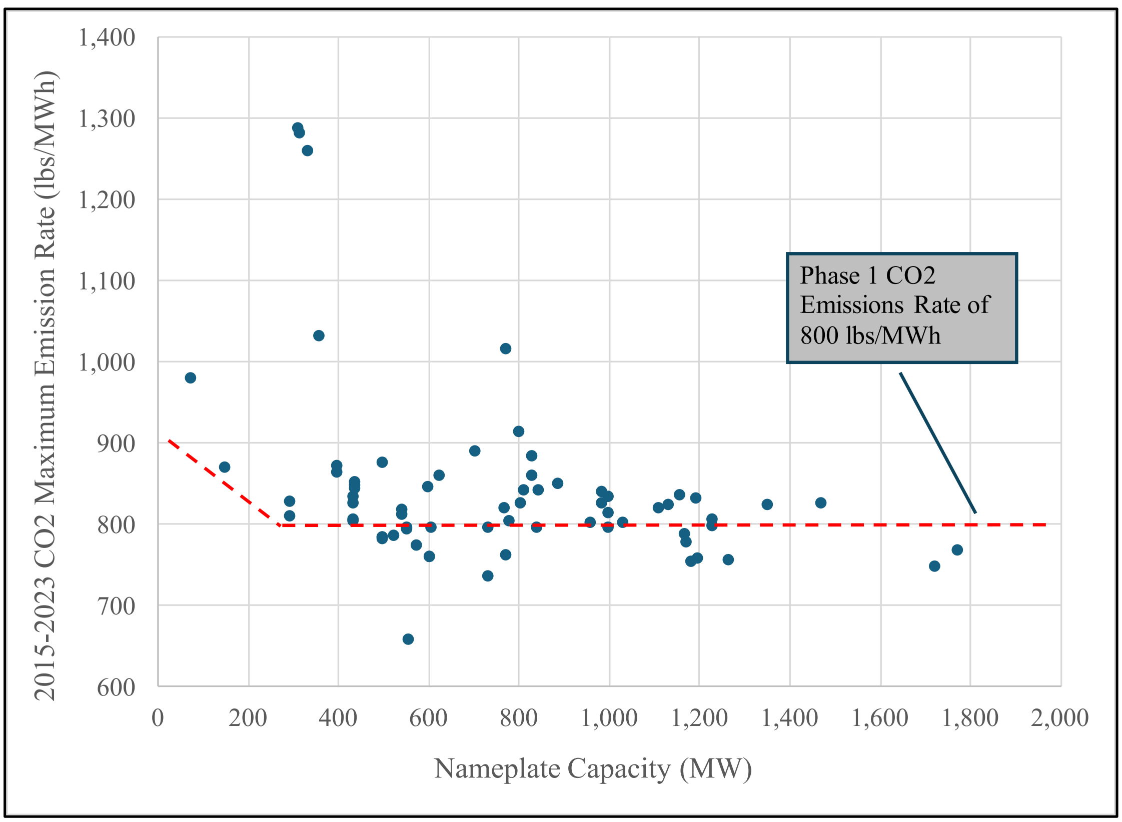


Figure 3-4. CO_2 Emissions Rate vs. Nameplate Capacity: Combined Cycle Units

Observations

The simple cycle and combined cycle databases used for this study identified more units than used by EPA and found more operating in the qualified range of capacity factors. The most notable difference is for simple cycle, in which 146 units identified as possible reference candidates, in contrast to 87 by EPA. Screening these units for capacity factor above 20%, the EPA database yielded 16 units while this study identified 30. This study also evaluated a greater number of combined cycle units – 69 compared to 59 cited by EPA. All but 8 units operated at a 12-month rolling average capacity factor of 40% and greater. The differences in the databases employed by EPA and this study appear mostly due to inclusion by the latter of numerous units that entered service in the last four years. Additional observations are offered as follows:

General

Although simple and combined cycle units exhibit very different capacity factors, their duty cycle is similar. For both categories of units, the duty cycle ranges from approximately 60% to more than 90%, showing that when in service these units tend to operate at high load.

Simple Cycle

CO_2 emission rates reported using AMD are generally higher than those calculated from suppliers' specifications, even when accounting for the real-world operating factors that negatively impact heat rate presented in Section 2. For approximately 65% of the units evaluated in this study, the maximum of the 12-month rolling average CO_2 emission rate exceeds the 1,170 lbs/MWh rate; no units exceeding approximately 175 MW range are able to comply with the 2024 Phase 1 intermediate-load emission standard. A description of how CO_2 emission rates are affected on design basis, focusing on the aeroderivative class versus F-Class, J- and H-Class, is addressed in Section 4. Only turbines entering service in the last 10 years are included in this analysis, thus long-term degradation of these units could not be determined from reported data. This uncertainty will likely further complicate meeting the standard.

Combined Cycle

Similar to simple cycle, CO_2 emission rates for combined cycle CTs reported using AMD are generally higher than those calculated from suppliers' specifications, including the mean and maximum margins presented in Section 2. For 26 of the 62 units operating at a 12-month average capacity factor of 40% or higher, the maximum of the 12-month rolling average CO_2 emission rate exceeds the 800 lbs/MWh rate. Consequently, 42% of 2015+ units do not achieve the output-based Phase I Base Load Subcategory CO_2 emission rate limit of 800 lbs/MWh. A description of how CO_2 emission rates are affected on design basis, focusing on the aeroderivative class versus F-Class, J- and H-Class, is addressed in Section 4.

Section 4. Critique of EPA Emission Rate Selection Methodology

EPA described in the final GHG rule the methodology by which the Phase 1 NSPS CO_2 emission performance standards are selected for both simple cycle (i.e., intermediate load units) and the combined cycle (i.e., base load units).[31] EPA's database employs 87 simple cycle and 59 combined cycle units; this study evaluated 146 simple cycle and 72 combined cycle units.[32]

The methodology for selecting these Phase 1 CO_2 emission rates is reviewed for both simple and combined cycle units.

Simple Cycle

EPA considered 16 units in their database to select a feasible CO_2 emission rate. Significantly, all were of aeroderivative design – with two exceptions, both GE 7FA turbines.

EPA determined the maximum 12-month average for each unit over the years of duty. For the 16 subject units, the CO_2 emission rate ranged from 1,156 to 1,470 lbs/MWh, with an average of 1,241 lbs/MWh. EPA acknowledges that most of the reference population is aeroderivative designs, with some units employing "intercooling" to lower compressor parasitic power, thereby increasing electricity generated and improving net heat rate. EPA also acknowledges that intercooling is not broadly applicable due to the need for a cooling tower and additional plant footprint.

Nonetheless, EPA in selecting a CO_2 emission rate of 1,170 lbs/MWh cites three reference aeroderivative turbine designs: (a) GE LMS100, (b) Siemens SGT-A65, and (c) GE LM6000. The relevant CO_2 emission rate data reported by EPA for these units show about half comply with the Phase 1 emission limit.[33] EPA did not identify any differences in design or operation that differentiated the noncompliant units from the compliant units.

This approach is deficient. First, within the three aeroderivative models that the EPA selected to base the standard on, eight out of a total of 16 units do not meet that standard. It is unclear why half of the turbines designated as references fail to standard – perhaps due to their operating history and other factors. These units' thermal efficiency is inherent to their design and cannot be

[31] 89 Fed. Reg. at 39,946-48.

[32] EPA's database does not include generating units that entered commercial service after 2020; no rational is cited. This analysis, being able to access data through 2024, could include units that operated in 2021-2023 and have adequate data to calculate at least 12 datapoints of 12-month rolling averages. Consequently, this study was able to utilize 78 additional units (69 simple cycle, 9 combined cycle).

[33] See EPA-HQ-OAR-2023-0072-0060_attachment_6, Worksheet "Chart Data", columns N, O, and Q.

changed. Some factors that can affect these units' 12-month rolling average CO_2 emission rate are out of their operators' control. These include site conditions and the associated ambient temperatures over a 12-month period, and hardware degradation between scheduled maintenance cycles. Most – if not all –- operators follow recommended maintenance practices, and thus have no control of the inherent degradation of the units and the associated compromise in thermal performance and whether such performance losses are recoverable between maintenance cycles. The operator has control of how to run the unit, but in practice market demand determines the dispatch and therefore the frequency of load changes, startup/shutdown events, etc.

EPA does not appear to have evaluated why half the aeroderivative CTs of the models referenced to set the performance standard did not meet that standard, and whether—even theoretically—these units could have done anything to meet the standard.

Second, EPA's reliance on only three specific aeroderivative models is even more problematic. Figure 4-1 presents the theoretical heat rate specified by the supplier (i.e., full-load, ISO conditions) for a sample of aeroderivative and intermediate capacity frame turbines broadly available in the U.S. Figure 4-1 calls out the three aeroderivative turbine designs designated by EPA as the basis of the 1,170 lb/MWh standard for intermediate-load simple-cycle turbines.

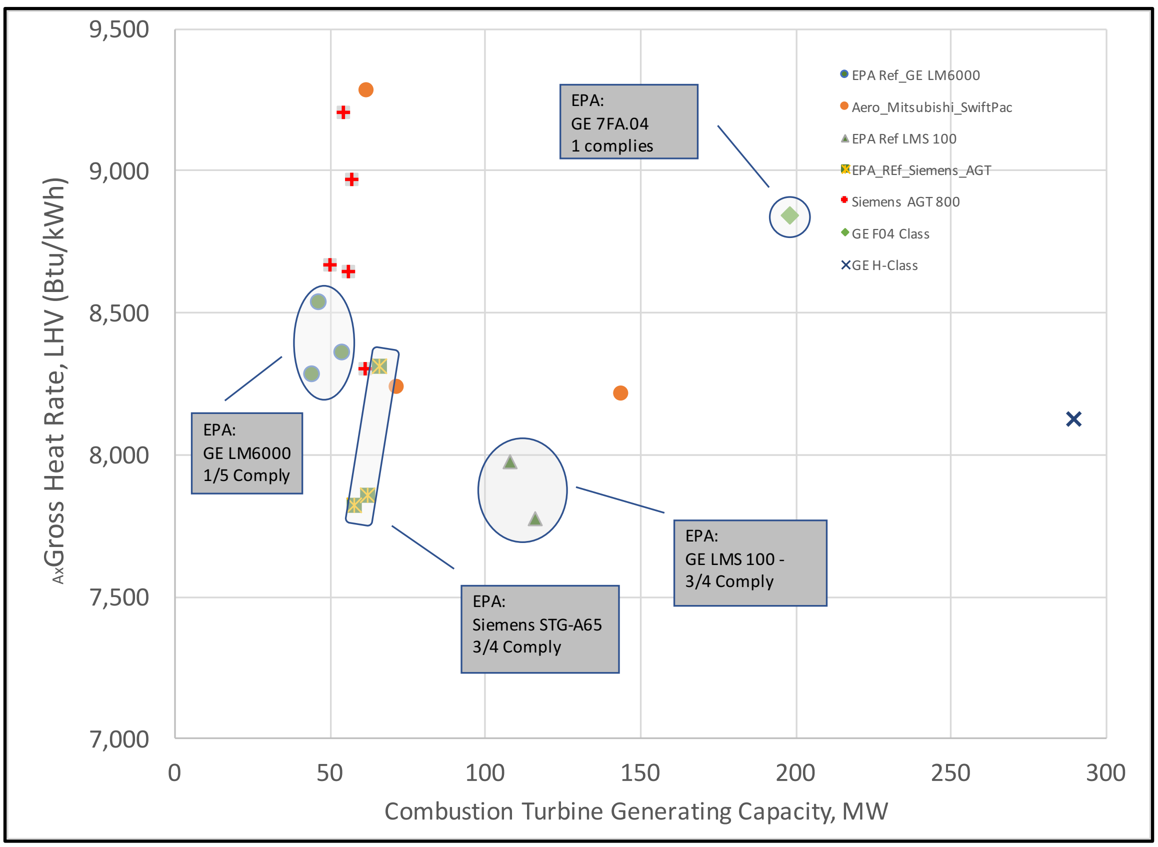


Figure 4-1. Combustion Turbines Suppliers' Specification of Gross Heat Rate: Aeroderivative and Frame Design of 50-300 MW

Putting aside the fact that half of the referenced model units did not meet the standard selected by EPA, any other CT model with an inherent (i.e., specification) heat rate exceeding that of the three aeroderivative models that EPA selected as the basis of the performance standard likely cannot meet the standard (at least not under operating duty and conditions similar to those experienced by the reference units). This includes many other aeroderivative models, as well as all E-Class and F-Class frame CTs, and all but the largest H-Class and J-Class frame CTs. All of these models are, effectively, limited to operating at low load (i.e., less than 20% capacity factor) because they cannot meet the intermediate load performance standard.

Figure 4-1 shows:

- EPA selected the two turbines with the lowest specified heat rate - the Siemens SGT-A65 and GE LMS100 to set the simple cycle CT CO_2 standard for units in the intermediate load subcategory. A third turbine – the GE LM6000 – presents similarly low specified heat rate in comparison to the remainder of the aeroderivative population. Almost without exception, the heat rates of all other aeroderivative-class turbines are higher. Establishing a 1,170 lb/MWh CO_2 emission rate standard effectively prohibits the use of aeroderivative-class turbine on the market for intermediate load duty, except for the three models favored by EPA.

- Many frame design turbines of 180-300 MW of generating capacity – representing likely candidates for simple-cycle applications in the U.S. – exhibit higher heat rates (and thus CO_2 emission rates). These turbines are desirable options for utilities due to their size, operating costs, and other operational factors. Several utilities have placed current orders for these units for several years out. EPA by setting the standard at 1,170 lb/MWh is effectively prohibiting the construction of most frame-design turbines with a capacity of 180-300 MW for intermediate load duty.

The aeroderivative design category does not represent the entire population of simple-cycle CTs. There are numerous differences in the design of aeroderivative compared to frame turbines – and not all the features of the former can be generalized or extrapolated to the latter. Most notably, aeroderivative turbines, due to their limited generating capacity and physical size, can utilize inlet compressors capable of delivering extremely high inlet pressures for combustion. This unique feature compromises EPA's near-exclusive use of this category as the reference case for simple cycle CO_2 emissions. The turbine inlet pressure is extremely important for this Brayton cycle – unlike the Rankine cycle deployed for fossil fuel-fired boilers and steam turbines, the simple cycle CT significantly benefits from high inlet pressure, elevating thermal efficiency. Inlet compressors for aeroderivative turbines elevate air pressure by a factor of 45-to-1 over ambient inlet pressure. Limits imposed by compressor suppliers on the maximum compressor blade "tip speed" prevent creating such high inlet pressures for frame turbines.[34] EPA did not identify high turbine inlet pressures as a component of BSER; clearly, this design feature influenced the choice of "highly efficient" units. However, as previously noted, the larger frame

---

[34] Compressor blade maximum tip speed is determined by the material strength and aerodynamic limits, which restricts rotational speed and the dimensions – and thus the power output - of the turbine. See *Gas Turbine Design Philosophy*, GE Power Generation, GE-3434D.

turbines requiring higher blade tip speed prevent this performance-enhanced feature from being applied on frame units.

Figure 4-2 compares the turbine inlet pressure ratio for aeroderivative and frame design turbines as a function of heat throughput. In the context of this discussion, the turbine inlet pressure ratio is the ratio of the air pressure delivered to the turbine combustor, relative to ambient air. This critical ratio for aeroderivative turbines (blue data and trend line) approaches 45, while for frame turbines this metric is limited to 25 (orange data and trend line).

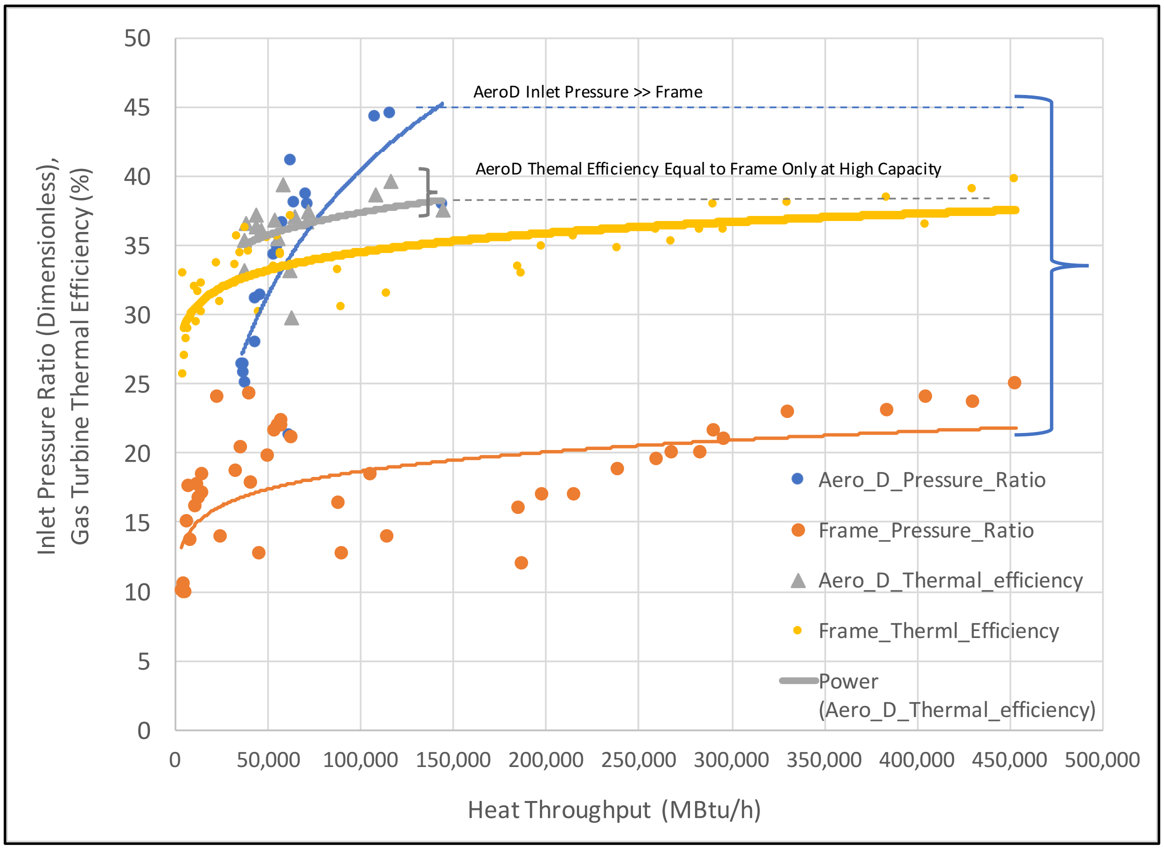


Figure 4-2. Combustion Turbine Inlet Pressure Ratio, Thermal Efficiency: Aeroderivative, Frame Designs

Figure 4-2 also shows the suppliers specified (inherent) thermal efficiency for each category of turbines. The figure shows that aeroderivative designs (gray data and trend line) enjoy higher thermal efficiency than frame designs (yellow data and trend line). Figure 4-2 also shows that the turbine inlet pressure ratio for frame turbines is well below that of aeroderivative – in many cases by half. As a result, the specified thermal efficiency of frame turbines in this category is less than aeroderivative by 2-4 percentage points. H- and J-Class units exhibit thermal efficiency approaching 40% – but only for these largest capacity turbines.

In summary, EPA's methodology of basing simple cycle CO_2 emission rates on aeroderivative turbines is flawed, as it allows the high inlet turbine pressure ratio achievable only on these smaller generating capacity units to drive the theoretical thermal efficiency of the CT and, therefore, its CO_2 emissions rate. Within the aeroderivative category, EPA selected among the most efficient units on which to base the standard. However, operating data show that the standard is not universally attained (in fact, it is attained by half of the aeroderivative population). EPA did not account for differences in units that could – and those that could not - attain the Phase 1 Intermediate Load limit.

Combined Cycle

EPA reviewed the emission rate data from 59 units in their database to select Phase 1 CO_2 emission standards for combined cycle units. EPA recognized the combined cycle CO_2 emission rate is affected by several design decisions, such as the arrangement of the combustion turbine, the HRSG, and the steam turbine, and means for cooling (wet or dry tower). Table A-2 in the Appendix presents examples of various arrangements – in addition to the most common arrangement of one combustion turbine/HRSG aligned with one steam turbine (1 x 1), the arrangement of two combustion turbines and HRSGs and one steam turbine (2 x 1) can generate greater power and extract higher thermal efficiency. This combined cycle arrangement is important in evaluating CO_2 emission rate.[35] EPA also recognized the operating point on the load curve – either near full nameplate capacity or at minimum load – drives the CO_2 rate.

EPA evaluated data from the 59 units operating since 2015 and determined the maximum 12-month rolling average of the population. The EPA reports 12-month rolling CO_2 emission rates ranging from 720 to 920 lbs/MWh, with an average of 810 lbs/MWh. EPA recognized that low-emitting units had features not applicable to the broad population of units, such as the Okeechobee Clean Energy Facility and the Dresden plant. These units' CO_2 emission rate averaged 770 lbs/MWh, enabled by a 2 x 1 arrangement and wet mechanical cooling towers, both of which reduce heat rate and CO_2 emission rate. Further, Okeechobee operates primarily at high load which further enables low CO_2 emission rates over a long averaging period (such as 12 months). Since most combined cycle units will likely be required to load follow during their lifetime, a limit based on high load operation is not broadly applicable to all operating cycles for most units covered by the NSPS.

Still, EPA singled out the Dresden plant as a reference unit, upon which EPA ultimately based its Phase 1 standard of 800 lb CO_2/MWh (for units larger than 2,000 MBtu/h):

> *.....the EPA has determined that the Dresden combined cycle EGU demonstrates that an emissions rate of 800 lb CO2/MWh-gross is achievable for all new large combined cycle EGUs with an acceptable compliance margin. Therefore, the EPA is finalizing a phase 1 standard of performance of 800 lb CO2/MWh-gross for large base load combustion turbines (i.e., those with a base load rating heat input greater than 2,000 MMBtu/h) based on the BSER of highly efficient combined cycle technology.*[36]

---

[35] The 2 x1 arrangement increases thermal efficiency but is also enhances operating flexibility by providing for online power generation while one combustion turbine undergoes maintenance and repair. Operating in this mode reduces thermal efficiency and increases output-based CO_2 emission rate. The Subpart TTTTa baseload emission limit should not prevent operation in this mode.

[36] 89 Fed. Reg. at 39,947.

The Dresden Plant is an unusual choice as a reference. The two GE 7FA combustion turbines precede two Voght high pressure HRSGs, and a single GE steam turbine – a 2 x 1 array. The original design F-Class turbines have been upgraded with GE Advanced Gas Path hardware.[37] This hardware is reported by GE to increase the combustion turbine thermal efficiency by 1.2% with a further potential increase in steam side thermal efficiency pending higher turbine effluent gas flow and higher gas temperature.[38] Also, the facility employs wet mechanical cooling towers, which lower heat rate and CO_2 emission rate. Although the use of wet cooling towers is not prohibited, their water use can complicate permitting in many areas.

Using the 59 units, EPA developed a database reflecting the conventional 1x1 arrangement and dry cooling tower by "adjusting" CO_2 emission from units with multi-shaft arrangement (increasing CO_2 by 1%) and wet cooling (increasing CO_2 by 1.4%).[39] EPA also recognized that operation at low load elevates CO_2 emission rate. Consequently, EPA used historical data from each unit describing CO_2 emission rate as a function of load to project any increase in emission at 40% capacity. Figure 4-3 presents data from the Dresden Plant used for this purpose.[40]

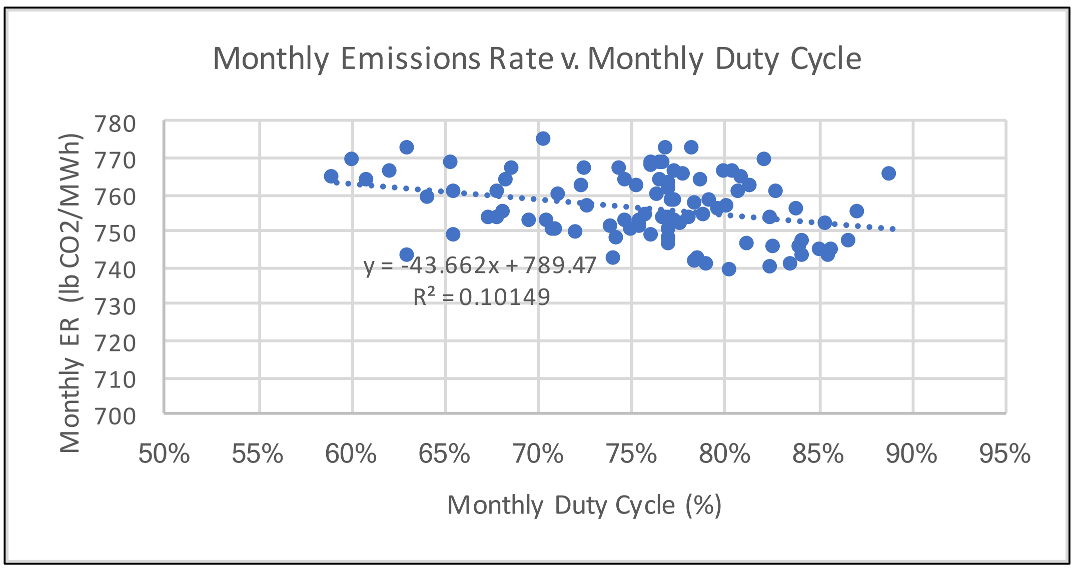


Figure 4-3. Example of Data Evaluation, Correlation Used for Dresden Plant Evaluation

There is no analysis in the 2024 rulemaking of whether the Dresden CO_2 emission performance is representative of what combined cycle units generally can achieve. First, Dresden is an F-Class based combined-cycle unit. It is not representative of smaller, E-Class and aeroderivative-based combined cycle units. In addition, the Dresden CO_2 data is not representative of the bulk

[37] AEP, personal communication, July, 2025.
[38] https://www.ge.com/news/press-releases/ges-advanced-gas-path-upgrades-generate-775-million-total-customer-value-annually
[39] CO_2 emissions from units with multi-shaft arrangements was elevated by 1% to translate to a 1 x 1 arrangement, and CO_2 from units with wet cooling tower was increased by 1.4% to account for a dry cooling tower.
[40] Adjustment factors to account low load (40% generating capacity) operation are derived for reference units in EPA_HQ-OAR-2023-0072-0060_attachment_4. See Worksheet Dresden 1A.

of operating F-Class and larger CT-based combined cycle units. This is evident from examining Figure 2-2, which presents the calculated CO_2 emission rate based on the suppliers' specification, and a "mean" adjustment of 12.5%. The CO_2 emissions in this figure for a 602-MW F-class combined cycle in 2 x 1 configuration is shown as 850 lbs/MWh. It should be noted that the value of 24% adjustment is implied by Figure 2-4 for the F-Class based population, approximating not the "mean" adjustment but the maximum. Also, Figure 2-4 shows a relatively high standard deviation of 171 lbs/MWh, implying approximately 6 units can emit at 751 lbs/MWh or less. This means the Dresden data resides in the lowest statistical cohort of F-Class combined cycle data.

Figure 4-4 depicts the data previously presented in Figure 3-4, but plotted as a function of capacity factor. The Dresden CO_2 emission rate of 771 lbs/MWh is called out on the figure for an annual capacity factor that averages 70% for the relevant operating years. As Figure 4-4 shows, there are approximately 10 units in the combined cycle population that emit CO_2 at a rate lower than Dresden; the vast majority of units in the database emit at higher rates. The increment provided by elevating the rate to 800 lbs/MWh does not significantly improve the margin for compliance for these units.

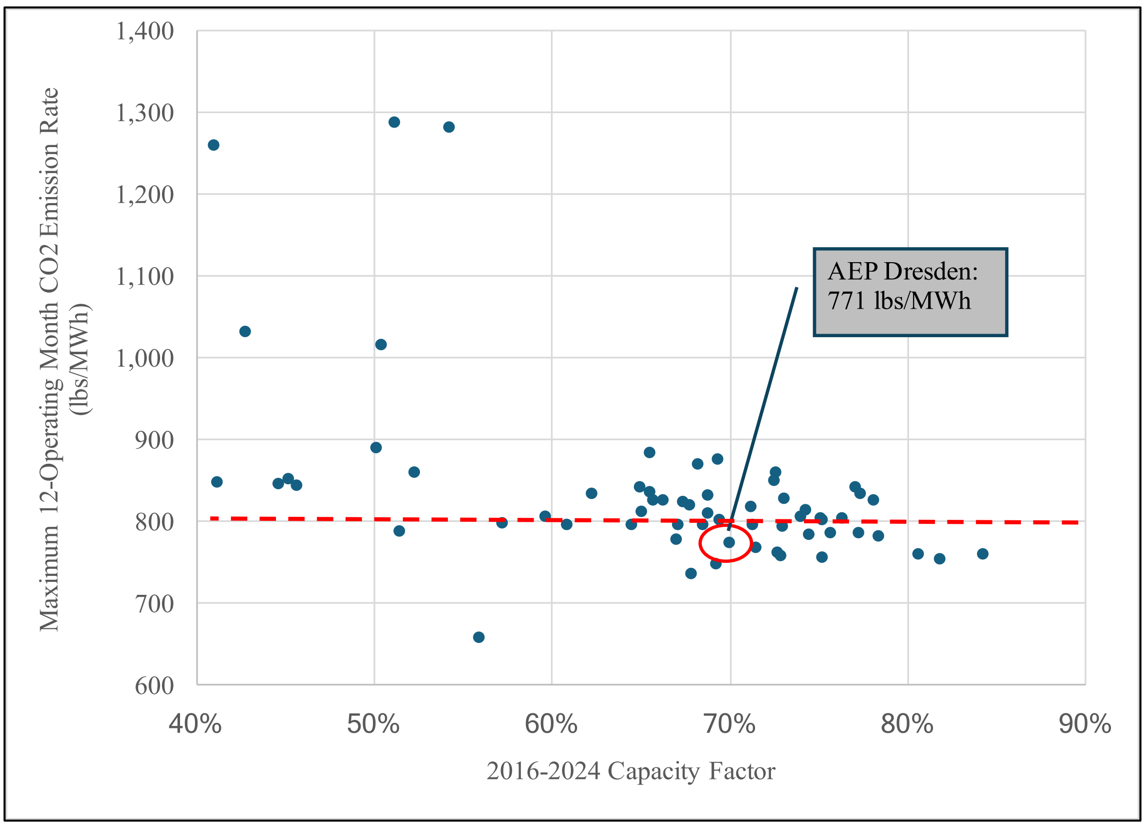


Figure 4-4. CO_2 Emissions from the Combined Cycle Population: Role of Dresden

EPA does not offer an analysis into the 2024 record as to why they determined any new combined-cycle unit ought to be able to achieve the CO_2 emission rate achieved by Dresden. As this study emphasizes, the 12-month rolling average efficiency (and, therefore, CO_2 emissions rate) of a combustion turbine is affected not just by the inherent efficiency of the unit, but also by operating conditions (i.e., elevation; average ambient temperature; unavoidable degradation; air inlet fouling; and condenser conditions) as well as operating duty (not just average capacity factor, but more importantly average duty factor; frequency of startup and shutdown; frequency and rate of load changes; etc.). Operating conditions are outside the control of the operator entirely. Operating duty is theoretically subject to operator control, though it is largely dictated by grid demand and constraints. EPA selected Dresden as representative, without analysis of whether Dresden itself would be able to meet the CO_2 emission rate EPA selected were Dresden located at a higher altitude, or operated at higher ambient temperature, or at a different duty (within the base load category). Nor did EPA analyze why the majority of operating combined cycle units in the database emitted CO_2 at a higher rate than Dresden. Without these analyses, there is no basis for concluding that any new unit should be able to meet the CO_2 rate that Dresden achieved under its own operating conditions and duty.

It is also clear that no combined-cycle unit with a base load rating less than 2,000 MBtu/h in the available database achieves the sliding-scale standard of 800 to 900 lb CO_2/MWh).

Conclusions

Simple Cycle. The 2024 Phase 1 output-based CO_2 emission performance standard for intermediate load turbines of 1,170 lbs/MWh for simple-cycle CTs operating at intermediate load is derived almost exclusively from aeroderivative design turbines, for which inlet turbine pressure ratio – among other factors unique to aeroderivative design – cannot be replicated on frame units. The ability to deliver inlet air pressure at a ratio of 45-to-1 (compared to ambient) that cannot be replicated on large frame engines due to a design limitation of compressors (per maximum blade tip speed). Such aeroderivative units are not representative of the larger frame-type units that could be deployed. Further, the three specific reference units represent an extreme edge of the thermal performance envelope for all simple-cycle CTs. Even within the aeroderivative models selected by EPA, not all units demonstrate compliance with the standard.

Combined Cycle. The combined cycle's 2024 Phase 1 CO_2 emission rate of 800 lbs/MWh (for units larger than 2,000 MBtu/h) is based on projection of thermal performance of a unit that is not representative of the turbine population. Without an analysis of why the vast majority of combined-cycle CTs in the database never met the selected standard, EPA cannot conclude any new unit should be able to meet the usually low CO_2 emission rate achieved by an outlier unit.

Section 5. Critique of Cost Evaluation: Simple, Combined Cycle LCOE Equivalency

The EPA's decision to select a 40% capacity factor as the threshold for the base load category is derived from a cost evaluation of the levelized cost of electricity (LCOE) for simple and combined cycle units.[41] In effect, EPA set the emissions standard for the base load subcategory (800-900 lb/MWh) to be achievable by combined-cycle CTs only; as a result, simple-cycle CTs, under the 2024 rule, are prohibited from operating at more than 40% capacity factor.

Section 5 critiques EPA's evaluation on several accounts. First, the analysis requires comparing performance and cost of simple and combined cycle units of identical generating capacity – for which a source does not exist in the available literature.[42] Thus, EPA elects to "create" four new reference cases, requiring up to four "adjustments" or "extrapolations" each of which introduces error. EPA does not account for these errors and the resulting uncertainty in its analysis. Second, for each of the four new reference cases, EPA selects a narrow range of input conditions that determine results (i.e. unit lifetime and natural gas price) which may not reflect future applications. Small changes to these inputs can substantially alter the results.

This section reviews EPA methodology and proposes an alternative approach. Moreover, regardless of the approach, small changes in assumptions yield significant changes in the LCOE analysis. This suggests that the deterministic LCOE analysis that EPA used to set the 40% capacity factor threshold for base load is not supported.

EPA Methodology

An overarching observation is that generating plant cost estimates are constantly evolving in response to the market. Capital cost estimates for both simple and combined cycle units have escalated in recent years, and may continue to do so pending supply chain issues. Generalized studies from entities such as the National Energy Technology Laboratory (NETL) and the Energy Information Administration (EIA) may not always accurately reflect the current economic climate, much less the economic climate in the next decade and beyond.

EPA references an NETL report that develops cost and performance data for a variety of natural gas-fired generating units.[43] These reference cases range from 50 MW aeroderivative turbines to several variants of combined cycle units with F-Class and H-Class turbines. The relevant

[41] Efficient Generation: Combustion Turbine Electric Generating Units Technical Support Document, Docket ID No. EPA-HQ-OAR—2023-0072, April 2024. At p. 31. Hereafter 2024 Efficient Generation TSD.
[42] Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, National Energy Technology Laboratory, May 2023.
[43] Ibid.

comparison is the LCOE for simple cycle versus combined cycle units at the same generating capacity.

The four generating capacities EPA selected for comparison are as follows:

- 100 MW. NETL provides the simple cycle design, with EPA creating the combined cycle version by "scaling" data from other sources.

- 50 MW. NETL results enable the extraction of a nominal 50 MW simple cycle design from the reference case. The combined cycle case is created by "scaling" cost and performance from reference units to extremely small scale.

- F-Class (375 MW). The NETL report provides the combined cycle reference case; the cost and performance for the CT in simple cycle is scaled.

- H-Class (560 MW). NETL provides the H-Class combined cycle reference; the cost and performance for the CT in simple cycle is scaled.

These four comparisons are developed as follows:

Aeroderivative Cases

The steps EPA cites to create 50 MW and 100 MW combined cycle units are as follows:

<u>Define New HRSG/Steam Turbine Cost</u>. EPA uses conventional "power-scaling scaling" laws to adopt cost for steam components from F-Class and H-Class units to the 50 and 100 MW capacity. The use of this method to scale cost by a factor of ten violates DOE/NETL standard practice, as advised in the *2013 Scaling Quality Guidelines* that power-law exponents be used with caution. [44] Specifically, DOE/NETL caution that "…..*there is a large percentage difference between the scaling parameters. This is particularly true for the major equipment items.* The use of this methodology to scale by more than a factor of 10 is beyond the conventional range.

<u>Implement Cost "Deducts" to Account for Scope Differences</u>. The HRSG and steam turbine costs for the F- and H-Class units exhibit features not typical of small aeroderivative-based combined cycle. Thus, capital costs must be reduced, as an auxiliary boiler (2.2%) is not required for fast-start, and the lower steam pressure HRSG and steam turbine (3.9% reduction) are also considered. A further cost "deduct" of 40% for the HRSG was adopted to account for lower heat throughput, as these smaller units use intercooling which reduces the heat removed.

To estimate fixed and variable operating and maintenance costs, EPA extrapolated those costs developed for the larger F-Class and H-Class units.

---

[44] Quality Guidelines for Energy Systems Studies, Capital Cost Scaling Methodology, DOE/NETL DOE/NETL DOE/NETL-341/013113, January 2013. At 18.

Each of these adjustments can introduce an error of 10% or more. Perhaps most significant is the use of a power-scaling law to translate capital cost from one generating capacity to another. There are two flaws in EPA's application. First, EPA uses the power-scaling law well outside the advised limit. The cost for steam-side equipment is scaled from the 375 MW F-class or 560 MW H-class units to 50 and 100 MW aeroderivative units. As noted in the 2013 DOE/NETL Scaling Guideline, the use of conventional power-law scaling methodology introduces significant risk when there is a large difference between the reference and the target capacity.[45]

Second, the scaling "exponent" of 0.6 represents conventional practice and does not necessarily represent the values relevant for thick-walled, high-pressure components.[46] The technical literature on cost scaling describes a wide range of exponents depending on equipment type. Specifically, a classic engineering treatment of cost evaluation states that most scaling exponents can range from 0.27 to 1;[47] and many "cluster" around 0.6 and it is convenient in certain cost-estimating actions to adopt "six-tenths" for the power law. The selection of a scaling exponent per this criterion is not a rigorous basis for a cost study with national policy implications. Regarding the use of the "sixth-tenth" exponent, Peters and Timmerhaus note:

> *the application of the 0.6 rule-of-thumb for most purchased equipment is an oversimplification of valuable cost concept since the actual values of the cost capacity factor vary from less than 0.2 to greater than 1.0 as shown in Table 5. Because of this, the 0.6 factor should only be used in absence of other information*.[48]

For power generation, the Electric Power Research Institute (EPRI) Technical Assessment Guide recommends scaling the cost of power generation equipment by using exponents that vary from 0.24 to 0.28.[49] Exponents of this value are appropriate for scaling the cost of entire power-generating facilities – including foundations, high-pressure steam components, and precision equipment such as steam turbines.

A major cost adjustment for which little basis is presented is the 40% reduction in HRSG costs due to the use of inter-stage cooling.

As an aside, comparison of 50 MW and 100 MW units is likely not relevant. As EPA explains, an owner of a 50 or 100 MW simple cycle will utilize this unit to meet different mandates in terms of ramp rate and would not consider a 100 MW combined cycle unit.

---

[45] Ibid. At 18. There are limitations on the ranges that can accurately be addressed by the scaling approach. There can be step changes in pricing at certain equipment sizes that may not be captured by the scaling exponents. Care should be taken in applying the scaling factors when there is a large percentage difference between the scaling parameters. This is particularly true for the major equipment items.
[46] EPA notes "The rule of six-tenths is a generic approach to estimating economies of scale". See 2024 TSD, footnote 110.
[47] *Plant Design and Economics for Chemical Engineers, Fourth Edition*, Peters M.S. and Timmerhaus K.D. McGraw Hill International Editions, Chemical and Petroleum Engineering, 1991. See page 170, Table 5.
[48] Ibid. Page 169.
[49] EPRI Technical Assessment Guide, Electricity Supply – 1993, EPRI TR-102276-V1R7, Volume 1: Rev. 7. See page 8-11.

F-, H-Class Comparison

The NETL cases of CC1A-F and CC1A-H are combined cycle reference cases at 375 MW and 560 MW respectively. EPA extracts the simple cycle generating unit cost and performance and adjusts it to a comparable generating capacity. EPA employed the following steps.

<u>Adjustment 1</u>. "Subtract" the cost of components dedicated to the steam cycle and associated hardware. The result is a simple cycle cost for F- or H-Class unit.

<u>Adjustment 2</u>. EPA utilizes steam side costs from a 2009 World Bank Study, which projects steam cycle equipment costs derived from 1996 to 2003, to refine the combined cycle costs of F-Class and H-Class.[50] The reference chart on page 32 of the Technical Support Document[51] could not be identified in the source document. This step could introduce significant error.

<u>Adjustment 3</u>. EPA estimated fixed cost and the fixed and variable operating and maintenance costs for the new combined cycle unit by extrapolating the NETL reference cases by relative heat inputs between the NETL and new reference cases.

Every one of these adjustments and estimates relies on assumptions that can substantially influence the results, as well as engender a fair amount of uncertainty.[52] EPA then selected a 30-year unit lifetime and natural gas price of $4.43/MBtu to determine LCOE.

The projected capital cost for these new reference cases contains numerous uncertainties which should be considered in the significance of the conclusions. Every one of these adjustments and estimates relies on assumptions that can influence the results substantially and promote uncertainty. Table 5-1, extracted from the TSD, shows that – particularly at a 40% capacity factor – the difference in cost range is from "zero" to 2%, which is decidedly small in the context of the assumptions and adjustments.

---

[50] *Study of Equipment Prices in the Power Sector*, Energy Sector Management Assistance Program, Technical Paper 122/09, January 2009. Hereafter 2009 Equipment Prices Study

[51] *Efficient Generation: Combustion Turbine Electric Generating Units Technical Support Document*, Docket ID No. EPA-HQ-OAR-2023-0072, April 2024.

[52] It should be noted the explanation of the steps executed by EPA as described by the *2024 Efficient Generation TSD* are not clear and do not portray an understanding of the EPA's actions. Specifically, the description presented does not describe how data from the *2009 Equipment Prices Study* are used in lieu of the cost available describing steam side components as presented in the F-Class and H-Class cases of the 2023 NETL study.

Table 5-1. Comparison of LCOE: EPA Manufactured Reference Cases

	Steady State LCOE ($/MWh)							
Capacity Factor (%)	F-Class Combined Cycle	F-Class Simple Cycle	H-Class Combined Cycle	H-Class Simple Cycle	100 MW Aeroderivative Combined Cycle	100 MW Aeroderivative Simple Cycle	50 MW Aeroderivative Combined Cycle	50 MW Aeroderivative Simple Cycle
5%	308	237	268	205	428	380	506	448
10%	166	136	146	119	229	207	267	242
20%	96	86	85	76	130	121	147	139
30%	72	69	65	62	96	92	107	104
40%	60	61	54	55	80	78	87	87
50%	55	56	48	50	70	69	75	77
60%	48	53	44	47	63	64	67	70
70%	45	50	41	45	58	59	62	65
80%	43	49	39	44	55	56	57	61

Alternative Approach

A 2024 EIA analysis[53] is a better reference study for this purpose. This 2024 study contains one reference case that can be used without adjustment; only one "case" needs to be created by extrapolating costs over a small range. EPA cites this 2024 EIA work but does not utilize it.

This EIA work (conducted by Sargent & Lundy) developed capital and operating costs for two reference cases employing an H-Class combustion turbine. A simple cycle design generating 419 MW at a heat rate of 8,873 Btu/kWh is represented by Case 4, with a Case 6 combined cycle generating 627 MW at a heat rate of 6,222 Btu/kWh (comprised of a 453 MW combustion turbine and 192 MW steam turbine). The Case 6 combined cycle design can be extrapolated from 627 MW to the Case 4 capacity of 419 MW, within the advised application of scaling laws.

The comparison of simple versus combined cycle units at approximately 450 MW reflects the present commercial marketplace. For example, among the combined cycle commercial offerings in Appendix A Tables A-1 and A-2 are Siemens simple and combined cycle units employing the SGT6-8000HL combustion turbine at comparable generating capacities. GE offers a simple and combined cycle unit using the GE HA.02 combustion turbine, generating 384 MW in simple cycle and 573 MW in combined cycle. These commercial offerings are well reflected by the reference cases cited by this study.

Table 5-2 presents two cases relevant for this analysis at 419 MW. The cost and performance characteristics for the EIA H-Class Case 4 and the adjusted Case 6 to match the 419 MW output are summarized. Capital costs are scaled as are fixed and variable O&M costs.

[53] Energy Information Agency, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, January 2024.

Table 5-2. Referenced Cases per Energy Information Administration Performance, Cost

Variable	**Case 4: SC, H-Class**	**Case 6: CC, H-Class**	**Case 6 Adjusted per Output**
Capacity, MW	419	627	419
Capital, $/kW)	838	921	
Scaling exponent: 0.6			1,082
Scaling exponent: 0.5			1,127
Heat Rate (Btu/kWh)	9142	6226	6226
Fixed O&M, $/kW-yr	6.87	16.46	20.14
Var O&M ($/MWh)	1.24	3.33	4.07

Table 5-2 demonstrates the uncertainty inherent in the input assumptions, by reporting capital scaled by using both EPA's selection a "0.6" exponent, and a value of "0.5" – a difference that reflects scaling for high pressure, thick walled components. Notably, the use of "0.5" versus "0.6" lowers the capital cost of the combined cycle from $1,127/kW to $1,082/kW – a 4% difference, which influences the outcome.

Figure 5-1 presents results of calculations reporting the LCOE (as $/MWh) from the EIA study. Three options are addressed: the 419 MW simple cycle (Case 4), the 627 MW combined cycle (Case 6), and an extrapolated "new" combined cycle unit of 419 MW combined cycle (extrapolated Case 6). The LCOE is presented as a function of capacity factor. Figure 5-1 results are presented for generating capacity, combined cycle capital cost, and natural gas price that differ very slightly from those employed by EPA. Specifically, these are slightly shorter lifetime (25 years), higher capital cost (resulting from the use of a 0.5 scaling factor), and a natural gas price ($4.00/MBtu). These represent small changes from EPA's input and are at least equally representative of future conditions.

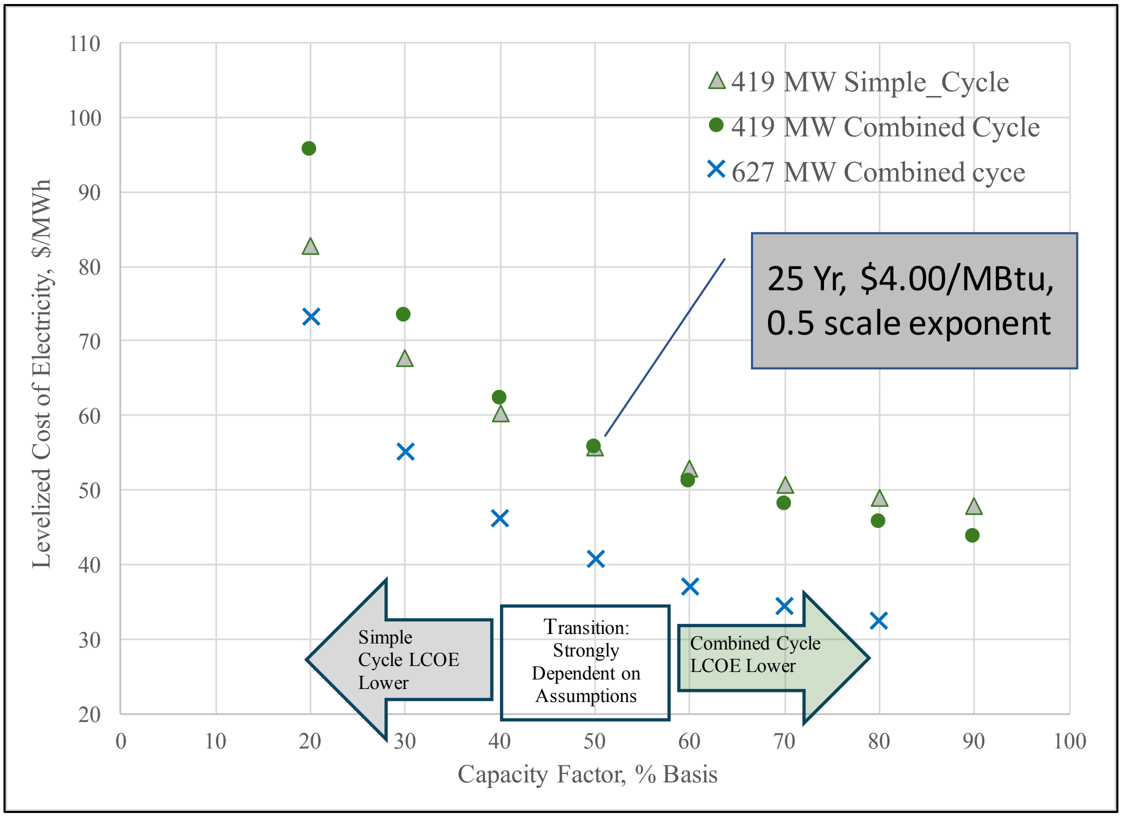


Figure 5-1. LCOE Equivalent per Adjusted EIA Analysis

Figure 5-1 shows that, using these factors, the LCOE from a simple cycle remains lower than that of a combined cycle up to a capacity factor of 52%.[54] The LCOE from the 627 MW (Case 6) combined cycle unit is significantly lower for the same 25-year lifetime and $4.00/MBtu natural gas costs, enabled by strong economies of scale.

Conclusions

EPA's conclusion that at 40% capacity factor the LCOE of a future combined cycle unit equates to that of simple cycle is highly uncertain, and based on assumptions that may not reflect future duty. EPA's use of an NETL study and the need to implement up to 4 "adjustments" to create new reference cases can introduce significant error, and bias the results to favor the combined cycle.

An alternative cost evaluation using a 2024 EIA study requires minor scaling of cost to derive comparable reference cases. The use of these EIA-derived reference cases and a 25-year unit life, natural gas cost of $4.00/MBtu, and a "scaling" exponent in agreement with literature for high-pressure components shows simple cycle LCOE lower than combined cycle up to 52% capacity factor.

[54] Exactly replicating EPA's inputs of a 30-year lifetime, natural gas cost of $4.43/MBtu, and the "default" scaling exponent shows simple cycle LCOE less than combined at 52% capacity factor.

Due to uncertainties introduced by EPA's methodology and the selection of key input values, using 40% capacity factor to define the base load segment of generation is not justified. The evaluation of simple cycle versus combined cycle LCOE described in this report highlights flaws in EPA's analysis. The methodology proposed by this report, not requiring the large number of extrapolations, is as reasonable as EPA's and justifiably supports a 52% threshold. Moreover, NSPS is forever. The economics of producing electricity could change. It may not be appropriate for EPA to mandate that simple-cycle CTs can never be used for base load operations (at whatever level EPA selects for this load subcategory).

Appendix A. Reference Supplier Combustion Turbine Data

Table A-1. Simple Cycle Units

	Turbine Supplier/Model	Output (MW)	Heat rate (Btu/kWh, LHV)
J-Class			
Mitsubishi	M501JAC	453	7755
H-Class			
Ansaldo	GT36	563	7935
Siemens	SGT6-8000HL	440	7898
GE	7HA.03	430	7884
GE	7HA.02	384	8009
Siemens	SGT6-8000H	328	8530
GE	7HA.01	290	8120
G-Class			
Mitsubishi	M501GAC	283	8531
F-Class			
Ansaldo	GT26	370	8322
Siemens	SGT6-5000F	260	8530
GE	7F.05	239	8871
GE	7F.04	201	8873
GE	6F.03	88	9277
E-Class			
Siemens	SGT6-2000E	119	9611
GE	7E.03	90	10107
Mitsubishi	M501DA	113	8930
Aeroderivative			
Mitsubishi	FT4000SwiftPac 140	144	8209
GE	LMS100 PA+	117	7702
Mitsubishi	FT4000SwiftPac 70	71	8232
Mitsubishi	FT4000SwiftPac 60	62	9281
GE	LM6000 DLE PF+	54	8277
GE	LM6000 SAC PG	54	8666

Table A-2. Combined Cycle Units

Class			Array	Output (MW)	Heat Rate (Btu/kWh, LHV)
J-Class	Mitsubishi	M501JAC	1 x 1	664	5332
			2 x 1	1332	5315
H-Class	Ansaldo	GT36	1 x 1	800	5451
			2 x 1	1605	5433
	Siemens	SGT6-8000HL		440	5416
	GE	7HA.03	1x1	648	5342
			2x1	1298	5332
		7HA.02	1 x 1	573	5381
			2 x 1	1148	5365
	Siemens	SGT6-8000H	1x1	465	5530
			2x1	960	5530
	GE	7HA.01	1x1	438	5481
			2x1	880	5453
G-Class	Mitsubishi	M501GAC	1x1	427	5640
			2x1	856	5652
F-Class	Ansaldo	GT26	1 x 1	540	5594
			2 x 1	1083	5575
	Siemens	SGT6-5000F	1 x 1	387	5725
			2 x 1	775	5715
	GE	7F.05	1 x 1	379	5667
			2 x 1	762	5640
		7F.04	1 x 1	309	5716
			2 x 1	602	5675
		6F.03	1x1	135	5998
			2x1	272	5994
E-Class	Siemens	SGT6-2000E	1x1	178	6354
			2x1	356	6354
	GE	7E.03	1x1	140	6514
			2x1	283	6454
	Mitsubishi	M501DA	1 x 1	167.4	6193
			2 x 1	336.2	6083
Aero-D	Mitsubishi	FT4000SwiftPac 140	1 x 1	180	6682
	GE	LMS100 PA+	1 x 1	137	6567
			2 x 1	247	6555
	Mitsubishi	FT4000SwiftPac 70	1 x 1	89.3	6734
	Mitsubishi	FT4000SwiftPac 60	2 x 1	85	6878
	GE	LM6000 DLE PF+	1 x 1	54	8277
	GE	LM6000 SAC PG	1 x 1	54	8666

Appendix B. Units Not in EPA Study

Table B-1. Units Excluded from EPA Data Base

plant_id	plant_name	Units	State	Cycle	In Service Date
3	Barry	1	AL	C	2023
56	Lowman Energy Center	1	AL	C	2023
136	Seminole (FL)	1	FL	C	2023
6061	R D Morrow	1	MS	C	2023
55460	Indeck Niles Energy Center	1	MI	C	2022
57185	Cricket Valley Energy	3	NY	C	2020
58001	Panda Temple Power Station	1	TX	C	2015
58478	LEPA Unit No. 1	1	LA	C	2016
59220	Wildcat Point Generation Facility	1	MD	C	2018
60356	South Field Energy	2	OH	C	2021
60903	Salem Harbor Power Development	2	MA	C	2018
60925	Montgomery County	1	TX	C	2021
60927	Lake Charles Power	1	LA	C	2020
61028	Hickory Run Energy Station	1	PA	C	2020
62192	Blue Water Energy Center	1	MI	C	2022
47	Colbert	3	AL	S	2023
141	Agua Fria	2	AZ	S	2022
492	South Plant	5	CO	S	2023
641	Gulf Clean Energy Center	4	FL	S	2021
1378	Paradise	3	KY	S	2023
3456	Newman	1	TX	S	2023
10350	Greenleaf 1	1	CA	S	2022
55129	Desert Basin	2	AZ	S	2022
56298	Roseville Energy Park	2	CA	S	2022
56350	Colorado Bend Energy Center	2	TX	S	2023
57943	Lonesome Creek Station	3	ND	S	2015
60387	Invenergy Nelson Expansion LLC	2	IL	S	2023
1	Astoria Station	1	SD	S	2021
61242	Tres Port Power, LLC	1	TX	S	2019
61966	Victoria Port Power II LLC	2	TX	S	2022
62548	SJRR Power LLC	2	TX	S	2022
63259	Delta Energy Park	1	MI	S	2022
63335	HO Clarke Generating	3	TX	S	2021
63688	Topaz Generating	10	TX	S	2021
64383	Braes Bayou Plant	8	TX	S	2022
65372	Mark One Power Station	6	TX	S	2022
65373	Brotman Power Station	6	TX	S	2023