March 18, 2019

U.S. Environmental Protection Agency
EPA Docket Center
1200 Pennsylvania Avenue NW
Washington, DC 20460

Submitted Electronically via Regulations.gov

Attn: Docket ID No. EPA–HQ–OAR–2013–0495
RE: Comments of Environmental Defense Fund on EPA's Proposed Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 83 Fed. Reg. 65,424 (Dec. 20, 2018).

On behalf of its over two million members and supporters, the Environmental Defense Fund ("EDF") submits the attached comments opposing the Environmental Protection Agency's ("EPA's" or the "agency's") December 20, 2018, proposed rule[1] (or "Proposal") to weaken the current new source performance standards for greenhouse gas emissions from fossil fuel-fired power plants[2] (or "2015 Final Rule") and allow new coal-fired power plants to emit far greater amounts of harmful climate and air pollution. These comments are supplemental to two joint comment letters being filed by EDF and other public health and environmental organizations on issues pertaining to climate science and to EPA's legal basis for regulating climate pollution from fossil fuel-fired power plants.[3] In addition to two reports by Andover Technology attached to this filing,[4] EDF is also submitting a separate appendix of materials that are cited to in these comments.[5]

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[1] Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 83 Fed. Reg. 65,424, (Dec. 20, 2018) [hereinafter "Proposal"].
[2] 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) [hereinafter "2015 Final Rule"].
[3] Joint Comments of Environmental and Public Health Organizations on Issues Pertaining to the Endangerment Finding in EPA's Proposed Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units: Comments Pertaining to the Endangerment Finding, Docket ID No. EPA–HQ–OAR–2013–0495, (Mar. 18, 2019); Joint Comments of Environmental and Public Health Organizations on Climate Science and Climate Change As They Pertain to EPA's Proposed Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA–HQ–OAR–2013–0495, (Mar. 18, 2019).
[4] Andover Technology Partners, NEW SOURCE PERFORMANCE STANDARDS FOR COAL STEAM EGUS (February 28, 2019) [hereinafter ANDOVER 2019 REPORT]; Andover Technology Partners, NATURAL GAS COMBINED CYCLE NEW SOURCE PERFORMANCE STANDARDS (Feb. 28, 2019).
[5] Appendix of Environmental Defense Fund to Comments Regarding EPA's Proposed Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric

We urge EPA to withdraw this Proposal and strengthen the 2015 Final Rule to better protect communities from climate and health risks. EPA's proposal would place no meaningful limits on carbon pollution from new coal-fired power plants, and even gestures towards the possibility of leaving carbon pollution from these plants entirely unregulated under section 111 of the Clean Air Act. Moreover, the Proposal was published mere weeks after the end of the comment period on EPA's proposed rollback of the Clean Power Plan—another harmful proposed rule that would eviscerate our nation's only federal limits on climate pollution from existing fossil fuel-fired power plants. Like EPA's proposed "replacement" for the Clean Power Plan, this Proposal is deeply damaging to public health and welfare, rests on a fatally deficient record, and represents an abdication of EPA's legal obligations under the Clean Air Act.

This Proposal comes at a time when increasing numbers of individuals are seeing their lives devastated by hurricanes, wildfires, drought, extreme heat waves, and other hazards linked to climate change.[6] Vulnerable populations such as the elderly, children, low-income communities, and communities of color are most at risk and often least-equipped to respond.[7] We are now able to draw a clearer line between climate pollution and the impacts to communities than ever before.[8] The record supports *strengthening* the current standards for new power plants,[9] and the urgent threat of climate change clearly counsels in favor of protective standards; yet EPA proposes to leave communities defenseless.

EPA does not—and cannot—dispute the risk to human health and the environment posed by climate change, yet it attempts to obscure the issue. The preamble of the proposed rule does not mention the term "climate change" at all, and EPA's economic impact analysis devotes a mere one paragraph to remind us that EPA's standing conclusion is that "elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare" and that "[s]ince 2009, other science assessments suggest accelerating trends."[10] Indeed expert agencies of this Administration—including EPA—jointly contributed to the Fourth National Climate Assessment released in November 2018, which only underscored the urgent threat posed by climate change. That Assessment highlighted that "[d]ecisions that decrease or increase emissions over the next few decades will set into

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Utility Generating Units, Docket ID No. EPA–HQ–OAR–2013–0495, (Mar. 18, 2019) (submitted via flash drive delivered to EPA Docket Center).

[6] *See, e.g.,* John Schwartz, *'Like a Terror Movie': How Climate Change Will Cause More Simultaneous Disasters*, N.Y. TIMES (Nov. 19, 2018), https://www.nytimes.com/2018/11/19/climate/climate-disasters.html.

[7] U.S. GLOBAL CHANGE RESEARCH PROGRAM, IMPACTS, RISKS, AND ADAPTATION IN THE UNITED STATES: FOURTH NATIONAL CLIMATE ASSESSMENT, VOL. II 36 (Nov. 2018), https://nca2018.globalchange.gov/.

[8] *Id.* at 58-59 ("The impacts and costs of climate change are already being felt in the United States and changes in the likelihood or severity of some recent extreme weather events can now be attributed with increasingly higher confidence to human-caused warming.").

[9] 2015 Final Rule, 80 Fed. Reg. at 64,548. (showing standards for coal-fired power plants could be strengthened); Andover Technology Partners, NATURAL GAS COMBINED CYCLE NEW SOURCE PERFORMANCE STANDARDS (Feb. 28, 2019) (attached) (showing standards for NGCC plants could be strengthened).

[10] EPA, ECONOMIC IMPACT ANALYSIS FOR THE REVIEW OF STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS, EPA 425/R-18-005 2-6 (Dec. 2018) [hereinafter NSPS Economic Impact Analysis].

motion the degree of impacts that will likely last throughout the rest of this century, with some impacts (such as sea level rise) lasting for thousands of years or even longer."[11]

EPA has a legal obligation under the Clean Air Act—and a moral responsibility—to ensure that the pollution driving these destructive impacts from any new fossil fuel-fired power plants is reduced to the "maximum practicable degree."[12] Fossil fuel-fired power plants are the leading contributor to carbon pollution among stationary sources,[13] and even one new coal-fired power plant could operate for decades and individually emit millions of tons of carbon pollution each year.[14] Controlling pollution from coal fired-power plants is also essential to protect fenceline communities from other harmful air pollution, including $PM_{2.5}$, NO_X, and SO_X. It is deeply misleading for EPA to suggest that this rulemaking is of no significance because it expects few, if any, new coal-fired power plants to come online, particularly as this Administration simultaneously works to prop up coal-fired generation with actions such as the proposed replacement of the Clean Power Plan,[15] the Department of Energy's coal bailout proposal,[16] and EPA's attack on the Mercury and Air Toxics Standards.[17]

The difference between the current standards and the proposed standards is stark. The current standards reduce carbon pollution from a new coal-fired power plant by 16 to 23 percent, consistent with reductions that can be achieved using highly-effective partial carbon capture and sequestration ("CCS"). In contrast, most existing coal-fired power plants are already out-performing the standard that EPA has proposed.[18] Under the Proposal, for a 600 MW facility, EPA expects emissions of CO_2 will rise by 1.1 million short tons per year and emissions of SO_2 will rise by 500 short tons per year relative to the current standard.[19] EPA fails to properly account for these lost benefits and its economic impact analysis presents an unlawfully one-sided account that underestimates costs and arbitrarily fails to monetize the anticipated harm from increased CO_2 and SO_2 pollution.

EPA seeks to weaken the current standards of performance based on a proposed new determination that supercritical and subcritical steam conditions, rather than partial CCS, are the best system of emission reduction ("BSER"). But, as our comments detail, under the mandates of section 111(b), EPA cannot reasonably determine that supercritical and subcritical steam conditions are a *better* system of emission reduction than partial CCS—much less that that they

[11] U.S. GLOBAL CHANGE RESEARCH PROGRAM, IMPACTS, RISKS, AND ADAPTATION IN THE UNITED STATES: FOURTH NATIONAL CLIMATE ASSESSMENT, VOL. II at 1351 (Nov. 2018), https://nca2018.globalchange.gov/.
[12] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 437 (D.C. Cir. 1973).
[13] EPA, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS (1990-2016), at ES-6, tbl. ES-2 (Apr. 12, 2018).
[14] Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1,430, 1,455 (Jan. 8, 2014) (EPA explained as the basis for its 2015 Final Rule that "the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year. . .").
[15] Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 82 Fed. Reg. 48,035, (Oct. 16, 2017).
[16] Department of Energy, Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (Oct. 10, 2017).
[17] National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review, 84 Fed. Reg. 2,670 (Feb. 7, 2019).
[18] Andover Technology Partners, NEW SOURCE PERFORMANCE STANDARDS FOR COAL STEAM EGUS (February 28, 2019).
[19] NSPS Economic Impact Analysis, *supra* note 10 at 2-3.

are the *best* system. As EPA concluded in the 2015 Final Rule after reviewing a robust technical record, partial CCS is adequately demonstrated and is of reasonable cost. Since that determination, even more large-scale CCS projects have come online and costs have continued to decline. Partial CCS affords air pollution benefits that far exceed supercritical and subcritical steam conditions—which have been in use since the 1970s and are hardly the advanced technology that Congress intended to promote through the Clean Air Act.

EPA now proposes to find that partial CCS technology is not of reasonable cost or adequately demonstrated, but centers its reasoning around "worst case" configurations for new power plants that are extremely unlikely to occur, that EPA has not substantiated in the record, and in some cases have never been demonstrated. Throughout the Proposal, EPA dismisses partial CCS as the BSER based on unsupported assumptions that new power plants will utilize the least efficient, most resource-intensive configurations (including combinations of fuel and cooling technology that have never been utilized together), will locate in those areas of the country least amenable to CCS technology, and will fail to take advantage of readily available opportunities to offset costs. The Clean Air Act, however, does not require EPA to establish new source performance standards based on such remote and implausible scenarios, and doing so is inconsistent with the statute's aim to secure the greatest pollution reductions practicable.

As our comments explain, EPA's new cost analysis contains fatal errors, including use of transportation and storage costs and capacity factors that artificially inflate the costs of partial CCS; an arbitrary focus on absolute versus relative costs that fails to make a legal determination that the industry would be unable to survive the additional incremental costs as it has demonstrated capacity to do; and an arbitrary dismissal of the potential for enhanced oil recovery, 45Q tax credits, and expected cost declines for CCS technology to alleviate the cost of compliance. EPA also repeatedly makes the unreasonable assumption—contrary to its own record—that new coal-fired power plants will be built in restructured electricity markets. Given current market conditions, new coal-fired power plants are likely only to appear in regulated markets, where owners and operators would only consider coal instead of more economical and lower-emitting sources for reasons unrelated to cost competitiveness. EPA fails ever to overcome its conclusion, based on the record for the 2015 Final Rule, that this industry can readily absorb the capital costs of partial CCS and that the resulting cost of electricity is similar to that for non-natural gas baseload technologies comparable to coal. Thus EPA falls short of making the operative legal finding required to show that the costs of partial CCS are not reasonable.[20]

We also address EPA's unsupported new assertion that partial CCS is not adequately demonstrated, and explain why the availability of water resources and geologic sequestration sites does not place significant constraints on the geographic availability of partial CCS. EPA's new determination that geologic sequestration sites are not widely available throughout the United States has no factual basis, and is contradicted both by the extensive record underlying the 2015 Final Rule and subsequent information. Further, EPA completely fails to acknowledge or rebut its finding in the 2015 Final Rule that the widespread availability of transmission

[20] *Portland Cement Ass'n. v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975) (costs are reasonable unless "the costs of meeting standards would be greater than the industry could bear and survive" or if "[t]he industry has [] shown inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed.")

infrastructure, as well as non-CCS technologies that enable new coal-fired power plants to comply with the current standard, make the standard "achievable by fossil fuel-fired steam generating units for all fuel types, under a wide range of conditions, and throughout the United States."[21] EPA's claims regarding water availability are equally meritless: EPA provides no data or analysis to support its assertion that arid regions of the United States lack sufficient water resources to support partial CCS. Moreover, EPA artificially inflates the water requirements for partial CCS and fails to consider demonstrated methods to reduce water consumption that allow owners and operators to implement partial CCS even in areas where water is scarce.

EPA also fails to duly consider other alternatives such as co-firing with natural gas, integrated gasification combined cycle technology (IGCC), or natural gas combined cycle technology (NGCC) as the best system of emission reduction. Even if EPA could reasonably conclude that supercritical and subcritical steam conditions were the best system of emission reduction, our comments and supporting analysis show that the standards of performance EPA proposes based on this system are far too weak. Power plants can readily achieve greater emission reductions using this 50-year-old technology (and are doing so), and the Proposal therefore does not comport with section 111's mandate that EPA set standards that control emissions by reflecting what is "achievable" using the "best system."

For all the reasons we present in these comments, EPA must withdraw the Proposal and strengthen the current standards to ensure all air pollution emitted from fossil fuel-fired power plants is properly controlled to the maximum practicable degree.

We appreciate your careful consideration of these comments. Please direct any inquiries regarding these comments to Tomás Carbonell, Director of Regulatory Policy at EDF, at tcarbonell@edf.org or 202-572-3610.

Respectfully submitted,

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[21] 2015 Final Rule, 80 Fed. Reg. at 64,513.

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Attachments

- Andover Technology Partners, New Source Performance Standards for Coal Steam EGUs (Feb. 28, 2019)
- Andover Technology Partners, Natural Gas Combined Cycle New Source Performance Standards (Feb. 28, 2019)

I. EPA Has Authority to Regulate GHG Emissions from Fossil-Fuel Fired EGUs Without Making a New Endangerment Finding

We join and fully support the separate comments submitted to this docket by a coalition of environmental and public health organizations,[22] responding to EPA's statements that it "will consider comments on the correctness of the EPA's interpretations and determinations and whether there are alternative interpretations that may be permissible," specifically as to "whether the Agency does have a rational basis for regulating CO_2 emissions from new coal-fired electric utility steam generating units and whether it would have a rational basis for declining to do so at this time."[23] Here, we provide additional analysis indicating that the agency's previous approach to determining that it has a rational basis to regulate GHGs emitted by this source category is sound. EPA has correctly not reopened this approach, nor has it proposed any alternatives to it.[24] It would be unlawful for the agency to finalize any alternative approach.

In 2015, EPA concluded that it possesses authority to regulate GHG emissions from fossil fuel-fired EGUs under section 111 for two reasons: (1) there was no new evidence calling into question its determination that "GHG air pollution may reasonably be anticipated to endanger public health and welfare"; and (2) fossil fuel-fired EGUs have a "high level of GHG emissions."[25] These considerations hew closely to the statutory factors that inform the decision whether to list a source category in the first place—namely, whether the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[26] In fact, the agency confirmed that, even if it were required to issue endangerment and significant contribution findings under this provision in order to regulate GHGs emitted by EGUs, the same information that underpinned its rational basis conclusion would support such findings.[27]

This approach, which closely parallels the listing analysis but does not require formal endangerment or cause-or-contribute findings, is legally sound. The statute is clear that a formal endangerment finding is required to initially list a sector to be regulated under section 111—and is also clear that such a finding is *not* required before regulating additional harmful pollutants from a previously-listed sector.[28] Because Congress did not provide specific criteria for regulating additional pollutants from a source category that is already listed under section 111, it is reasonable to look to the statutory factors that trigger regulation initially when deciding

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[22] Joint Comments of Environmental and Public Health Organizations on Issues Pertaining to the Endangerment Finding in EPA's Proposed Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units: Comments Pertaining to the Endangerment Finding, Docket ID No. EPA–HQ–OAR–2013–0495, (Mar. 18, 2019).
[23] Proposal, 83 Fed. Reg. at 65,432 n.25.
[24] *See id.*
[25] 2015 Final Rule, 80 Fed. Reg. at 64,530.
[26] 42 U.S.C. § 7411(b)(1)(A).
[27] 2015 Final Rule, 80 Fed. Reg. at 64,350.
[28] *See Russello v. U.S.*, 464 U.S. 16, 23 (1983) ("Where Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally in the disparate inclusion or exclusion.") (alterations omitted).

whether to require reductions of other pollutants.[29] Indeed, the statutory factors for listing a source category—the endangerment and cause-or-contribute findings—provide a floor for when EPA *must* regulate an additional pollutant from a listed source category under the rational basis inquiry. It would be irrational to fail to regulate an additional pollutant simply because a source category was already listed, if the same evidence regarding that pollutant would have triggered a formal listing of that source category had the source category not previously been listed. Thus, it would be arbitrary for the agency to decline to regulate a pollutant on the basis of considerations wholly unrelated to the harms that pollutant poses or the quantities in which it is emitted from a particular source category.

Under section 111, EPA lists a source category based on its findings as to endangerment and significant contribution and then regulates one or more pollutants from the source category.[30] The agency need not conduct a separate rational basis inquiry in developing standards for the pollutants evaluated in the endangerment and contribution findings, because those findings consider the same questions as the rational basis inquiry, and by specifying the process Congress has clearly enunciated what is required for listing and therefore logically relevant to any decision whether to regulate a pollutant under section 111. The rational basis inquiry is a direct outgrowth of the listing process and the findings made in that process—considering whether the pollutant may endanger public health or welfare and whether the source category causes or contributes significantly to emissions of that pollutant in quantities that are dangerous. The rational basis inquiry, with its foundation in the more formal listing process, therefore ensures that EPA regulatory actions are rational and non-arbitrary, as is required under the CAA.[31]

For all these reasons, the agency's approach to deciding whether to regulate an additional pollutant from a source category was correct in 2015 and remains valid today. EPA rightly has not proposed to alter this approach.

II. EPA's Proposed Withdrawal of its 2015 Determination that Partial Carbon Capture and Sequestration Constitutes the Best System of Emission Reduction for New Coal-Fired Electric Generating Units is Unlawful and Arbitrary.

Under section 111(b) of the Clean Air Act, the Administrator is required to establish federal standards of performance for new sources which "reflect[] 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*."[32] The requirement to fully consider each of these factors applies both when the Administrator is issuing new standards and when she is revising previously-issued standards.[33]

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[29] *See White Stallion Energy Ctr., LLC v. EPA*, 748 F.3d 1222, 1236 (D.C. Cir. 2014), *rev'd on other grounds sub nom. Michigan v. EPA*, 135 S. Ct. 2699 (2015) ("EPA reasonably relied on the [statutory] criteria to inform its interpretation of the undefined statutory term. . . . ").
[30] 42 U.S.C. § 7411(b)(1)(A)-(B).
[31] *See id.* § 7607(d)(1)(C), (d)(9)(A).
[32] *Id.* § 7411(a)(1), (b)(1) (emphasis added).
[33] *Id.* § 7411(b)(1)(B).

The statute and case law provide that the Administrator "must" determine the "best" system by balancing factors including the "amount of air pollution" reduced by application of the system,[34] the "cost" of application of the system, "any nonair quality health and environmental impact" of application of the system, the "energy requirements" of application of the system,[35] and how application of the system encourages "technological innovation."[36] The Administrator must then "identify the emission levels that are 'achievable'" using the best system.[37]

In order to determine the "best" system of emission reduction, EPA must necessarily consider and compare alternative systems—including any system currently in place—and explain why EPA's newly chosen system is *better*. *Cf. Nat'l Hells Canyon Ass'n v. Fed. Power Comm'n*, 237 F.2d 777, 784 (D.C. Cir. 1956) (in the context of the Federal Power Act, "the word 'best' is of course superlative and suggests comparison of two or more applications for licenses under § 4(e)."). Bedrock principles of environmental law similarly require EPA to consider reasonable alternatives and explain why the chosen course is better than those alternatives. *See, e.g.*, *Del. Dep't of Nat. Res. v. EPA*, 785 F.3d 1, 18 (D.C. Cir. 2015) ("Because EPA too cavalierly sidestepped its responsibility to address reasonable alternatives, its action was not rational and must, therefore, be set aside."); *Allied Local & Reg'l Mfrs. Caucus v. EPA*, 215 F.3d 61, 80 (D.C. Cir. 2000) ("To be regarded as rational, an agency must also consider significant alternatives to the course it ultimately chooses."); *Neighborhood TV Co. v. FCC*, 742 F.2d 629, 639 (D.C. Cir. 1984) (reviewing courts must "ensure that the agency took a 'hard look' at all relevant issues and considered reasonable alternatives to its decided course of action") (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 41–43 (1983)).

When revising a standard of performance, then, EPA must explain why the new standard is the "best" in consideration of all the statutory factors. This includes explaining why the current standard no longer reflects the "best" system. *See, e.g.*, *State Farm,* at 48 ("We have frequently reiterated that an agency must cogently explain why it has exercised its discretion in a given manner . . . ."). When an agency issues a new policy which "rests upon factual findings that contradict those which underlay its prior policy" or "when its prior policy has engendered serious reliance interests" the agency must "provide a more detailed justification than what would suffice for a new policy created on a blank slate."[38] In this case the agency must provide "a reasoned explanation . . . for disregarding facts and circumstances that underlay or were engendered by the prior policy."[39]

EPA claims that the "primary reason" it is now revising its selection of the BSER "is the high costs and limited geographic availability of CCS."[40] This contradicts the factual and legal findings EPA made in the 2015 Final Rule, when it determined that "[b]ased on consideration of relevant cost metrics in the context of current market conditions, the EPA concludes that the

[34] *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981).
[35] 42 U.S.C. § 7411(a)(1), (b)(1)(B).
[36] *Sierra Club*, 657 F.2d at 346.
[37] *Id.* at 330 (quoting 42 U.S.C. § 7411(a)(1)).
[38] *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515 (2009).
[39] *Id.* at 516.
[40] Proposal, 83 Fed. Reg. at 65,426.

costs associated with the final standard are reasonable"[41] and that "[b]oth deep saline and oil and gas formation types [in which geologic sequestration is feasible] are widely available in the United States."[42] As explained further in this section of the comments EPA arbitrarily fails to justify—and cannot justify—a finding that the current standard of performance based on partial CCS is not achievable or that partial CCS is not adequately demonstrated, and falls far short of showing that the newly proposed BSER represents the best balance of the statutory factors.

"An adequately demonstrated system 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."[43] Courts have noted that "section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present . . . ."[44] And "an achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption."[45] As EPA found in the 2015 Final Rule, the current standards easily meet these requirements and EPA provides scant new factual information or reasoned analysis to support overturning those findings now.

Below, we address EPA's claims regarding the cost and geographic availability of the current BSER, and explain why EPA's proposal to reverse its determination that partial CCS is the BSER is arbitrary. In violation of core administrative law principles, EPA fails to "examine the relevant data and articulate a satisfactory explanation for its action, including a 'rational connection between the facts found and the choice made'" and here offers "an explanation for its decision that runs counter to the evidence before the agency" and thus the Proposal cannot stand.[46]

Even further, the proposed rule fails to properly consider other important factors. In particular, courts have read the legislative history of section 111 to authorize EPA to balance long-term environmental effects, growth, cost savings, and technology incentives.[47] In the Proposal, EPA arbitrarily fails to consider the long-term environmental benefits that could be achieved by promoting CCS and spurring increased research, development, and utilization of this technology, which could help further drive down costs and achieve greater emissions reductions. Many commenters have noted that with support from government policies such as the 2015 Final Rule, CCS could see continued advancements that will help it grow commercially.[48]

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[41] 2015 Final Rule, 80 Fed. Reg. at 64,558.
[42] *Id.* at 64,576.
[43] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).
[44] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).
[45] *Essex Chem.*, 486 F.2d at 433–34.
[46] *State Farm*, 463 U.S. at 43 (quoting *Burlington Truck Lines, Inc. v. U.S.*, 371 U.S. 156, 168 (1962)).
[47] *See, e.g.*, *Sierra Club*, 657 F.2d at 331.
[48] GLOBAL CCS INSTITUTE, THE GLOBAL STATUS OF CCS 33 (2018) ("Once policy confidence is in place, long-term capital investments can be made and the virtuous cycle of investment and cost reduction will accelerate."); INTERNATIONAL ENERGY AGENCY, A POLICY STRATEGY FOR CARBON CAPTURE AND STORAGE 6 (2012), https://www.iea.org/publications/freepublications/publication/policy_strategy_for_ccs.pdf ("The scale of potential future deployment of CCS is enormous. . . . Deploying CCS requires policy action; it is not something that the market will do on its own."); Brief of Amici Curiae Technological Innovation Experts Nicholas Ashford, M.

Most critically, EPA fails to consider the environmental costs and air pollution impacts of its proposal to weaken a key safeguard against the urgent threat of climate change. EPA's decision to select a BSER that results in a less protective standard of performance over a more protective option, which, as it previously found, is "technically feasible . . . [,] available at reasonable cost, does not have collateral adverse non-air quality health or environmental impacts, and does not have adverse energy implications,"[49] is a clearly arbitrary determination and an abuse of its discretion to weigh the statutory factors in determining the "best" system of emission reduction.

A. EPA Admits that CCS Technology Is Commercially Available, Underscoring that Partial CCS Is Adequately Demonstrated

EPA fails to show that partial CCS is not "adequately demonstrated." If anything, CCS technology has only continued to advance and become more commercially available since the 2015 Final Rule. In formulating the current standards, EPA determined CCS to be adequately demonstrated on the basis of examination of EGUs that had or were utilizing carbon capture technology, the existence of commercial vendors offering carbon capture technology with performance guarantees, and public pronouncements by industry and technology developers' of their confidence in the feasibility and availability of CCS technologies.[50]

This evidence is more than sufficient to show that partial CCS is "adequately demonstrated" within the meaning of section 111(a). Courts have made clear that a BSER need not "be in actual routine use somewhere."[51] Moreover, EPA is permitted to "make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry."[52] Furthermore, confirming the technology-forcing purpose of section 111, the courts have held that EPA has authority "to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard."[53] And, EPA is permitted to "compensate for a shortage of data through the use of other qualitative methods, including the reasonable extrapolation of a technology's performance in other industries."[54]

Despite there being no requirement that the chosen system be commercially available, EPA acknowledges in the Proposal that CCS is available through commercial vendors, demonstrating its commercial availability.[55] EPA admits that the carbon capture technology is in

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Granger Morgan, Edward Rubin, and Margaret Taylor in Support of Respondents at 6–23, *North Dakota v. EPA*, No. 15-01381 (D.C. Cir. Dec. 21, 2016) (No. 1652263).

49 2015 Final Rule, 80 Fed. Reg. at 64,548.

50 *Id.* at 64,548–58.

51 *Portland Cement Ass'n*, 486 F.2d at 391 (quoting S. REP. NO. 91-1196 (1970)).

52 *Id.* at 391 (quoting *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)).

53 *Sierra Club*, 657 F.2d at 364.

54 *Lignite Energy Council v. EPA*, 198 F.3d 930, 933–34 (D.C. Cir. 1999).

55 Proposal, 83 Fed. Reg. at 65,444 (explaining without contesting EPA's previous finding that CCS technology is commercially available).

commercial use at the Boundary Dam and Petra Nova facilities.[56] Contrary to EPA's suggestions in the Proposal, these projects have only achieved greater success as time has passed, as explained below. Indeed, a major industry publication has stated that:

> [a]s demonstrated by Petra Nova (and Boundary Dam before it), the challenges for CCUS deployment are largely commercial, not technical. While scope exists for further technological progress, CCUS has been proven to be a viable climate mitigation technology. The stall in CCUS deployment has come about due to a market failure: without a requirement or strong incentive to significantly reduce CO_2 emissions there is little or no incentive for the private sector to develop and deploy CCUS technology.[57]

It is reasonable for EPA to consider that there will be continued advancements in this technology that will ease its utilization by any new coal-fired EGUs that do become subject to the standards, particularly given the rapid progress that has already helped propel CCS across the globe.

Around the world, there are 18 large-scale CCS facilities in commercial operation, five more are under construction, and 20 additional facilities are in various stages of development.[58] Since 2015, projects have continued to come online and achieve new milestones, creating yet more evidence that partial CCS is adequately demonstrated. Below is a description of just some of these projects that further demonstrate the feasibility of CCS.

- FuelCell Energy and ExxonMobil are working on a project at the hybrid coal/natural gas Barry plant in Alabama that will use carbonate fuel cells to separate methane and 90 percent of the CO_2 which can be used to generate electricity or be sequestered.[59]
- China National Petroleum Corp.'s Jilin Oil Field CO_2 EOR Demonstration Project has been in operation since 2009 and captures CO_2 from a natural gas processing plant using post-combustion capture with MEA absorption capture technology (which uses the solvent monoethanolamine to remove CO_2). It has continued to expand operations and in 2018 reached a storage capacity of 0.6 million tons of carbon dioxide annually and became the 18th large scale CCS facility in operation around the world.[60]
- Xinjiang Dunhua Oil Technology Co., Ltd. began capturing 100,000 tons of CO_2 annually from the Dunhua Methanol Plant in 2015 using post-combustion capture for use in enhanced oil recovery.[61]

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[56] *Id.* EPA states that it relied on a NETL report with analysis based on "the CO_2 removal system designed by Shell Cansolv, the system currently in full-scale commercial use at the Boundary Dam facility." NSPS Economic Impact Analysis, *supra* note 10 at 3-21.

[57] Liam McHugh, *Petra Nova Demonstrates Technical Potential – But that's Just One Side of the Coin*, WORLD COAL ASSOCIATION (June 20, 2018), https://www.worldcoal.org/petra-nova-demonstrates-technical-potential-thats-just-one-side-coin.

[58] GLOBAL CCS INSTITUTE, *supra* note 48, at 12.

[59] Matthew N. Eisler, Fuel Cells Finally Find a Killer App: Carbon Capture, IEEE Spectrum (May 29. 2018), https://spectrum.ieee.org/green-tech/fuel-cells/fuel-cells-finally-find-a-killer-app-carbon-capture.

[60] *Jilin Fact Sheet: Carbon Dioxide Capture and Storage Project*, MIT CARBON CAPTURE & SEQUESTRATION TECHNOLOGIES PROGRAM, http://sequestration.mit.edu/tools/projects/jilin.html (last updated Sept. 30, 2016); Joanna Sampson, *China "Setting the Pace" as it Establishes World's 18th Large-Scale CCS Facility*, GAS WORLD (Aug. 13, 2018), https://www.gasworld.com/china-establishes-worlds-18th-ccs-facility/2015265.article.

[61] GLOBAL CCS INSTITUTE, *supra* note 48, at 49.

- Sinopec Qilu Petrochemical CCS project is a large-scale facility currently in construction and expected to begin testing in 2019. The initial phase allows post-combustion capture of 0.4 million metric tons of CO_2 per year with a long-term target of 0.5 million metric tons of CO_2 per year by 2021 for use in enhanced oil recovery. It involves retrofit to an existing coal/coke water slurry gasification unit at a fertilizer plant.[62]
- Yanchang Petroleum in 2017 began construction of a large-scale CCS facility that will capture more than 400,000 metric tons per year of CO_2 from two coal to chemicals plants.[63]
- The Illinois Industrial Carbon Capture and Storage Project began operations in 2017, collecting 1 million tons of CO_2 per year from an ethanol production plant and storing it in a deep underground sandstone reservoir. [64]
- NET Power in May 2018 achieved first fire of its 50 megawatt thermal supercritical carbon dioxide CO_2 demonstration power plant and test facility in La Porte, Texas, designed to produce low-cost natural gas electricity with near-zero emissions.[65] Net Power uses oxy-combustion and recycles the CO_2 produced through combustion back to the combustor multiple times.[66]
- Japan's Tomakomai CCS hydrogen production unit has successfully captured and stored 200,000 metric tons of CO_2 since 2016.[67]
- Toshiba's Saga City CCS plant began commercial operation in 2016. The plant utilizes post-combustion capture to collect CO_2 emissions from waste incineration for cultivation of crops and algae, capturing 10 tons of CO_2 per day.[68]
- The Integrated Coal Gasification Fuel Cell Combined Cycle (IGFC) at the Osaki CoolGen project began demonstrations of oxygen-blown IGCC in 2017, began construction of the CO_2 capture unit in 2018 and will began full-scale demonstration operations of oxygen-blown IGCC with CO_2 capture in 2019.[69]

Research and development in combination with knowledge acquired and built upon from prior CCS projects means plants can now implement CCS more efficiently, at lower cost, and more easily than ever before. This shows in the feasibility study of retrofitting the 305MW coal-fired Shand Power Station with post-combustion CCS, which anticipates cost reductions of 67

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[62] Facilities Database, GLOBAL CCS INSTITUTE, CO_2RE, https://co2re.co/FacilityData (last visited Mar. 15, 2019) (Sinopec Qilu Petrochemical CCS entry in table).
[63] *Yanchang Petroleum's Large-Scale CCUS Facility Enters Construction in China*, HYDROCARBON PROCESSING (Mar. 20, 2017), https://www.hydrocarbonprocessing.com/news/2017/03/yanchang-petroleum-s-large-scale-ccus-facility-enters-construction-in-china.
[64] Press Release, Dep't of Energy, DOE Announces Major Milestone Reached for Illinois Industrial CCS Project (Apr. 7, 2017), https://www.energy.gov/fe/articles/doe-announces-major-milestone-reached-illinois-industrial-ccs-project.
[65] David Roberts, *That Natural Gas Power Plant with No Carbon Emissions or Air Pollution? It Works.*, VOX (June 1, 2018), https://www.vox.com/energy-and-environment/2018/6/1/17416444/net-power-natural-gas-carbon-air-pollution-allam-cycle.
[66] *Technology*, NET POWER, https://www.netpower.com/technology/ (last visited Mar. 15, 2019).
[67] GLOBAL CCS INSTITUTE, *supra* note 48, at 20, 62.
[68] *Giving CO_2 an Economic Value: Carbon Capture Technology Helps Recycle Waste into Resources*, TOSHIBA ENERGY SYSTEMS & SOLUTION CORPORATION (Mar. 14, 2018), https://www.toshiba-energy.com/en/thermal/topics/ccu.htm.
[69] Press Release, Osaki CoolGen Corporation, Osaki CoolGen Project (Apr. 2, 2018), https://www.osaki-coolgen.jp/en/news/pdf/20180402.pdf.

percent compared to implementation at Boundary Dam, involves a special design to integrate better with renewables and at variable load, and features a special heat-rejection design that removes the requirement for additional water.[70]

B. The Latest Information on the Petra Nova and Boundary Dam Facilities Supports EPA's Prior Determination that CCS Is Adequately Demonstrated

In its effort to cast doubt on the technical feasibility of partial CCS, EPA attempts to criticize or distinguish two partial CCS projects: Boundary Dam and Petra Nova.[71] But the agency's analyses of these projects is misleading and fails to reflect the substantial documentation of the feasibility of CCS that the performance of these projects provides.

With respect to Boundary Dam, a post-combustion carbon capture project retrofit to an existing coal-fired power plant in Saskatchewan, the sole operational problems that EPA identifies pertain to "multiple issues with the performance of the capture technology during its first year of operation (2014–15)."[72] EPA proceeds to "solicit[] comment on whether Boundary Dam's first-year operational problems cast doubt on the technical feasibility of fully integrated CCS."[73]

The Proposal's reference to first-year performance issues, presented with almost no explanation or analysis, is highly misleading. As EPA found and documented in its 2016 decision denying reconsideration of the 2015 Final Rule, in Boundary Dam's initial year of operation, "the CO_2 capture system is operating successfully, the unit meets the Canadian performance standard of CO_2 emissions (which is more stringent than the U.S. standard) and it is producing more CO_2 for enhanced oil recovery than called for by contract. Operational issues in the first year of operation were related largely to ancillary systems and not to the carbon capture system, and appear to have been successfully resolved."[74] SaskPower itself directly addressed these misplaced concerns in an amicus brief submitted in support of the 2015 new source performance standards (NSPS).[75] SaskPower stated that it had "anticipated issues as it moved from commissioning the process to ongoing full time standard operations,"[76] and that "[t]he

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[70] International CCS Knowledge Centre, THE SHAND CCS FEASIBILITY STUDY PUBLIC REPORT x-xi (Nov. 2018), https://ccsknowledge.com/pub/documents/publications/Shand%20CCS%20Feasibility%20Study%20Public%20_Full%20Report_NOV2018.pdf.
[71] Proposal, 83 Fed. Reg. at 65,444. As the Proposal acknowledges, problems that arose at another CCS project, the Kemper plant in Mississippi, were not related to the CCS component. *Id.* It therefore cannot be used to rebut viability of CCS technologies.
[72] *Id.*
[73] *Id.*
[74] EPA, BASIS FOR DENIAL OF PETITIONS TO RECONSIDER THE CAA SECTION 111(B) STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC UTILITY GENERATING UNITS 7 (2016).; *see also id.* at 8 to 12 (documenting these findings). In fact, much of the downtime incurred in the initial year of operation was due to a cracked storage tank—not the type of development which raises issues regarding the feasibility of the control technology. *Id.* at 8.
[75] *See* Brief of Amicus Curiae Saskatchewan Power Corporation, Operator of Boundary Dam Carbon Capture and Storage (CCS) Facility, in Support of Respondents, *North Dakota v. EPA*, No. 15-1381 (D.C. Cir. Dec. 22, 2016) (No. 1652543).
[76] *Id.* at 7.

operational issues faced are not a unique experience with any industrial process."[77] While the CCS facility experienced some outages for maintenance, "[t]hese outages were, and will be, part of the normal two-year cycle of planned maintenance outages that all SaskPower's coal-fired units undergo."[78]

Even if EPA were accurately characterizing Boundary Dam's first-year performance, it would be arbitrary and capricious for EPA to base its analysis entirely on that time period, considering that the unit has operated successfully for several subsequent years. In 2018, the Boundary Dam CCS facility achieved 94 percent availability (excluding periods when it was offline due to non-CCS-related issues at the power plant).[79] The facility captured over 625,000 metric tons of carbon in 2018, and has captured approximately 2.5 million metric tons of carbon over its lifetime so far.[80]

The Proposal also seeks to raise questions about the Petra Nova project in Texas—a CCS retrofit that was brought online on time and on budget, and completed without a single lost-time incident[81]—on the grounds that "it has not demonstrated the integration of the thermal load of the capture technology into the EGU steam generating unit (*i.e.*, boiler) steam cycle."[82] EPA does not explain why this in any way calls the BSER into doubt, other than to ask whether an EGU with a fully integrated carbon capture system could operate when the carbon capture system is not operating. The Proposal contains no evidence that this would be problematic, nor does it account for the experience of the fully integrated steam cycle at Boundary Dam, which has demonstrated the capacity of the plant to produce power even during those periods when the carbon capture system was offline.[83] And as discussed above, the first-year operational issues at Boundary Dam were largely unrelated to the carbon capture system, and were entirely unrelated to integration of the steam cycle.

The Proposal's pessimistic take on existing CCS projects—aside from being highly inaccurate—also fails to consider that EPA's BSER determination under section 111 must include "consideration of technological innovation."[84] Specifically, EPA has authority "to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved

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[77] *Id.* at 9.
[78] *Id.* at 8.
[79] *See BD3 Status Update: December 2018*, SASKPOWER (Jan. 11, 2019), https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-december-2018.
[80] *Id.*
[81] Sonal Patel, *Capturing Carbon and Seizing Innovation: Petra Nova Is POWER's Plant of the Year*, POWER MAGAZINE (August 1, 2017), https://www.powermag.com/capturing-carbon-and-seizing-innovation-petra-nova-is-powers-plant-of-the-year/.
[82] Proposal, 83 Fed. Reg. at 65,444.
[83] *See BD3 Status Update: December 2017*, SASKPOWER (Jan. 8, 2018), https://www.saskpower.com/about-us/our-company/blog/2018/03/bd3-status-update-december-2017 (containing graphs indicating that the power plant generated electricity even when no carbon was being captured); *see also BD3 Status Update: June 2017*, SASKPOWER (July 6, 2017), https://www.saskpower.com/about-us/our-company/blog/2018/03/bd3-status-update-june-2017 (indicating that the power plant could resume post-maintenance operations before the carbon capture system did).
[84] *Sierra Club*, 657 F.2d at 346; *see also* 2015 Final Rule, 80 Fed. Reg. at 64,556 ("[A]ll components of CCS are fully integrated at Boundary Dam.").

performance necessary to meet the standard."[85] As SaskPower wrote with respect to Boundary Dam, "The lessons learned during this time will be helpful for any future carbon capture and storage projects, whether undertaken by SaskPower or another party, which should result in reduced costs and even better and more reliable performance."[86] But the Proposal disregards the reality that CCS technology is advancing, and is appropriate for the new projects to which the 2015 Final Rule currently apply.[87]

In the Proposal, EPA has also requested comment on whether the government support provided for the Boundary Dam and Petra Nova projects "raises concerns as to the extent to which developers are willing to accept the risks associated with the operation and long-term reliability of CCS technology." As shown above, Boundary Dam does not raise doubts about the operation and long-term reliability of CCS technology, and EPA does not even suggest as much about Petra Nova. In the Response to Comments accompanying the 2015 Final Rule, EPA directly addressed questions about the role of government support. For instance, EPA observed that, even if that support was originally dedicated to supporting technologies that were not yet "viable" or "in commercial service," "that does not reflect the state of these technologies today."[88] Furthermore, "major types of energy used to generate electricity are routinely the beneficiaries of government subsidies or support," and therefore subsidies are not "conclusive that the technology is not or will not be commercially viable."[89] Indeed, the private sector provided the vast majority of funding for both Boundary Dam[90] and Petra Nova.[91] This investment in these advanced facilities is a strong, tangible sign of private sector interest in the further development and deployment of this technology.[92]

C. EPA Arbitrarily Ignores the Exorbitant Environmental Costs and Minimal Emission Reductions Achieved by Selecting Supercritical and Subcritical Steam Conditions as the BSER

Given this robust support for the feasibility of CCS, it is arbitrary and capricious for EPA to instead determine that supercritical and subcritical steam conditions alone are a *better* system than partial CCS—much less the "best" system. The courts have consistently held that EPA must

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[85] *Id.* at 364.
[86] Brief of Amicus Curiae Saskatchewan Power Corporation, *supra* note 75, at 9. In confirmation, the Petra Nova plant demonstrated an innovative means of shifting the geometry of the absorber from a round to a rectangular-style vessel, allowing extrapolation to a very large size. Patel, *supra* note 81.
[87] *See* Section II.A, *supra*, for a more detailed discussion of technological advances in CCS.
[88] EPA, STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FROM NEW STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS: RESPONSE TO COMMENTS ON JANUARY 8, 2014 PROPOSED RULE at 2-129 to -30 (Aug. 3, 2015) [Hereinafter RESPONSE TO COMMENTS ON 2014 PROPOSED RULE].
[89] *Id.* at 2-133.
[90] *Boundary Dam Integrated Carbon Capture and Storage Demonstration Project*, NATURAL RESOURCES CANADA, https://www.nrcan.gc.ca/energy/publications/16235 (last updated Jan. 5, 2016).
[91] *Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project*, MIT CARBON CAPTURE & SEQUESTRATION TECHNOLOGIES, https://sequestration.mit.edu/tools/projects/wa_parish.html (last updated Sept. 30, 2016); *Petra Nova – W.A. Parish Project*, DEP'T OF ENERGY, https://www.energy.gov/fe/petra-nova-wa-parish-project (last visited Mar. 12, 2018).
[92] Of course, federal funding in nascent pollution control technology is not unusual, and has led to signal successes in later commercial deployment. *See* Memorandum from Mike Laney, RTI International, on History of Flue Gas Desulfurization Use in United States – 1970-1976, at unnumbered p. 3 (July 11, 2015) [hereinafter History of FGD Use Memo] (federal funding for research and deployment of FGD scrubbers).

take into consideration the degree of air pollution reduction achieved when selecting the BSER[93] and that section 111 requires the "maximum practicable degree" of control of air pollution from new sources.[94] In line with the purpose of the Clean Air Act, courts have established that deference to EPA's choice of BSER will not extend to those situations where "the environmental . . . costs of using the technology are exorbitant."[95] The environmental costs of selecting supercritical and subcritical steam conditions as the BSER, and rejecting adequately demonstrated alternatives that would drive significantly greater reductions, clearly qualify as "exorbitant."

EPA's proposed new BSER clearly does not meet these statutory requirements or take any significant steps toward achieving environmental benefits. Failing to minimize carbon emissions from any new coal-fired power plants could be devastating to achieving emissions targets we must meet to prevent the worst impacts of climate change. According to expert reports based on the latest and best available climate science, the necessary emission target to achieve this goal is net zero emissions by mid-century.[96] This will require large and rapid emission reductions from fossil fuel-fired power plants, which are the largest source of greenhouse gases among stationary sources.[97] The need for EPA action is highlighted by reports that emissions from the power sector *rose* last year, despite the shift from coal-fired generation to less greenhouse gas-intensive natural gas plants.[98] Each new coal-fired power plant may operate for decades and individually emit millions of tons of carbon pollution each year.[99] Thus there is urgent need to ensure emissions from coal-fired power plants are reduced as much as possible—just as the Clean Air Act requires.

Yet, the BSER EPA now proposes relies upon technology that coal plants have been utilizing for decades. The resulting proposed standard would result in minimal, if any, pollution reductions from new coal-fired power plants compared to what coal-fired power plants are already achieving and far fewer reductions than what is eminently feasible under the current standards, which by definition represents a better system of emission reduction. As EPA acknowledges: "Close to 90 percent of the large coal-fired EGUs that have commenced operation since 2010 in the U.S. use either supercritical steam conditions or IGCC technology.

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[93] *Sierra Club*, 657 F.2d at 326 ("In any event, we can think of no sensible interpretation of the statutory words "best technological system" which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions.").
[94] *Essex Chem.*, 486 F.2d at 437 (citing Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970, 116 Cong. Rec. 42,384, 42,385 (1970)); *see also Sierra Club*, 657 F.2d at 326 (a standard of performance must "reduc[e] emissions as much as practicable.").
[95] *Lignite Energy Council*, 198 F.3d at 933.
[96] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, GLOBAL WARMING OF 1.5°C: SUMMARY FOR POLICY MAKERS 14 (2018), https://www.ipcc.ch/site/assets/uploads/sites/2/2018/07/SR15_SPM_version_stand_alone_LR.pdf.
[97] EPA, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS (1990-2016) at ES-6, tbl. ES-2 (2018), https://www.epa.gov/sites/production/files/2018-01/documents/2018_complete_report.pdf.
[98] *U.S. Energy-Related CO2 Emissions Increased in 2018 but Will Likely Fall in 2019 and 2020*, ENERGY INFO. ADMIN. (Jan. 28, 2019), https://www.eia.gov/todayinenergy/detail.php?id=38133.
[99] Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430, 1455 (proposed Jan. 8, 2014) [hereinafter 2014 Proposed Rule] (EPA explained as the basis for its 2015 Final Rule that "the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year").

The remainder of the capacity uses subcritical steam conditions."[100] EPA estimates the proposed BSER would achieve only a two percent reduction in emissions for large EGUs and nine percent for small EGUs.[101] As explained below and in the attached Andover Technology report, an analysis of the existing global fleet shows that the proposed standards for large units is only slightly lower than what the U.S. existing coal plant fleet is achieving on average (1900-2000 lb/MWh-gross)—facilities that on average have been in operation for *decades*; it is also, well above what the Japanese fleet is achieving on average (1700 lb/MWh-gross).[102] In comparison, the current standards require emissions reductions of 16 to 23 percent.[103] The economic impact analysis for the Proposal estimates that, compared to the proposed standard, the current standards would reduce emissions by 1.1 million tons per year at an illustrative power plant.[104] EPA's rejection of a standard that a massive record of evidence supports as being achievable and based on technology that has been adequately demonstrated is arbitrary in light of the significantly greater emission reductions available via CCS, particularly given the urgency of mitigating greenhouse gas pollution and reducing the risk of catastrophic climate changes.

EPA's proposal to find that supercritical/subcritical steam conditions represent the "best" system is also arbitrary because the agency has failed to take into account the monetized costs of harm to human health and the environment that result from increased pollution in its assessment of the costs and benefits of the proposal. As EPA admits, the metric of levelized cost of electricity (LCOE) it uses to judge the costs of the rule "represent[s] the cost to the generator and do[es] not reflect the additional social costs that are associated with emissions of greenhouse gases or other air pollutants."[105] Meanwhile, as described more fully in section III critiquing the economic impact analysis, EPA fails to quantify and monetize the loss of benefits from replacing the current standards with the Proposal—despite having monetized *both* costs and benefits in the 2015 Final Rule. EPA fails both to account for the cost of increased climate pollution as well as the lost benefits of reductions in other harmful air pollutants emitted from coal-fired power plants such as SO_2. As a result, EPA's proposal neglects the agency's mandate under section 111 to evaluate the amount of emission reduction achieved when determining the BSER,[106] and arbitrarily "fail[s] to consider an important aspect of the problem."[107] Were EPA to consider the cost of the additional pollution risked under this proposal (as it properly must under the law), the analysis would clearly show that the environmental cost of selecting supercritical and subcritical steam technology as the BSER is "exorbitant."

D. The BSER Selected in the Proposal Would Fail to Promote Advanced Technology

i. Selection of BSER Should Take into Account Promotion of Advanced Technology

[100] Proposal, 83 Fed. Reg. at 65,448.
[101] *Id.*
[102] Andover Technology Partners, New Source Performance Standards for coal steam EGUs at 8-9 (Feb. 28, 2019).
[103] 2015 Final Rule, 80 Fed. Reg. at 64,513.
[104] NSPS Economic Impact Analysis, *supra* note 10 at 2-3.
[105] *Id.* at 3-23.
[106] *See Sierra Club,* 657 F.2d at 326.
[107] *State Farm*, 463 U.S. at 43.

As EDF and other organizations explained in comments on the proposal for the 2015 Final Rule,[108] EPA is required to consider promotion of advanced technology as part of selecting the BSER. The legislative history of section 111 and the relevant case law affirm the Clean Air Act's aim of utilizing and promoting advanced technology that can protect the public from dangerous pollution. It is clear that partial CCS exemplifies Congress's view of an "adequately demonstrated"[109] technology and would be consistent with the promotion and utilization of advanced technology.

For instance, in the context of section 111, the Senate Report on the Clean Air Act Amendments of 1977 discussed the need "to assure the use of available technology and to stimulate the development of new technology."[110] The D.C. Circuit has also found that EPA must consider technological innovation when setting standards under section 111:

> Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.[111]

The agency may thus promulgate standards that reflect "improved design and operational advances" that industry has yet to realize at scale, "so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard."[112] That is true even if the standard is "set at a level that is higher than has been actually demonstrated over the long term by currently operating" technology.[113] Moreover, EPA can "extrapolat[e] . . . a technology's performance in other industries," and look beyond domestic facilities to those used abroad.[114]

EPA itself cited much of the relevant legislative history and case law in the 2015 NSPS. For example, the agency noted that,

> The Senate Report to the original section 111 likewise makes clear that it was not intended that the technology "must be in actual routine use somewhere." Rather, the question was whether the technology would be available for installation in new plants.[115]

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[108] *See* Environmental Defense Fund et al., Comment Letter on Proposed Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units (May 9, 2014).
[109] 42 U.S.C. § 7411(a)(1).
[110] S. REP. NO. 95-127, at 171 (1977).
[111] *Sierra Club*, 657 F.2d at 346.
[112] *Id.* at 364; *see also Portland Cement Ass'n v. EPA (Portland Cement III)*, 665 F.3d 177, 190 (D.C. Cir. 2011) (EPA properly based the NSPS for new cement kilns on a recent and more efficient model, even though many older kilns still existed that did not utilize the same technology).
[113] *Sierra Club*, 657 F.2d at 364.
[114] *Lignite Energy Council*, 198 F.3d at 934 & n.3.
[115] 2015 Final Rule, 80 Fed. Reg. at 64,556 n.241 (quoting S. REP. NO. 91-1196 (1970)).

In making this acknowledgment, EPA paraphrased a view of section 111 articulated by the D.C. Circuit just a few years after Congress passed the Clean Air Act Amendments of 1970.[116]

ii. The 2015 Final Rule's Standard Spurs Deployment and Advancement of CCS Technology

Consistent with congressional intent, the 2015 BSER promotes the development and deployment of more advanced and effective pollution-control technology. While EPA meticulously detailed why partial CCS already met the BSER requirements at the time of its selection, the agency also noted that the rule would support technological innovation.[117]

The effect on technological development was further elucidated in the amicus brief of technological innovation experts in litigation over the 2015 Final Rule.[118] Amici described the effectiveness of "demand-pull" policies, or regulations that increase demand for technologies that achieve a particular level of performance. Amici explained that "'[d]emand-pull' regulation is particularly important to incentivize the use of pollution-control technology."[119] Without such policies, technological innovation may be stymied by an "incentive gap" that results when polluting businesses are allowed to externalize the costs of pollution and therefore are not induced to install pollution-control technologies.[120] Regulations aimed at protecting health, safety, and the environment tend to have positive impacts on technological development.[121] This effect has a proven track record in the specific context of standards of performance for EGUs under section 111, so it is highly relevant to this Proposal.[122] Another example of this can be seen in the development and deployment of flue gas desulfurization scrubbing technology in the electricity generating sector, where:

> the existence of national government regulation for SO_2 emissions control stimulated innovation. The patent analysis in this dissertation shows that national regulation is a more effective stimulant of inventive activity than national legislation in support of air pollution abatement research alone, with no regulatory requirements. A second policy implication of this work is that regulatory stringency appears to be particularly important as a driver of innovation, both in terms of inventive activity and in terms of the communication processes involved in knowledge transfer and diffusion.[123]

Even before the amicus brief was submitted, EPA was fully aware of amici's research, which the agency cited in the 2015 Final Rule.[124] The agency concluded that "quantifiable technological improvements can be shown to occur solely on the basis of the experience of

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[116] *See Portland Cement Ass'n*, 486 F.2d at 391.
[117] 2015 Final Rule, 80 Fed. Reg.64,514 ("[I]mplementing partial CCS as the BSER in this rule is likely to further boost research and development in CCS technologies, making the implementation even more efficacious and cost-effective, while providing a competitive, low emission future for fossil fuel-fired steam generation.").
[118] *See* Brief of Amici Curiae Technological Innovation Experts, *supra* note 48.
[119] *Id.* at 16.
[120] *Id.*
[121] *See id.* at 16–17.
[122] *See id.* at 10–11.
[123] History of FGD Use Memo, *supra* note 92, at unnumbered p. 8.
[124] *See, e.g.*, 2015 Final Rule, 80 Fed. Reg. at 64,575 n.364.

operating an environmental control technology forced into being by government actions."[125] Of course, with respect to partial CCS, the control technology already exists and is being utilized. The impact of the 2015 Final Rule would be to increase deployment and spur further advancements in a proven, operational technology.

The amici also raised a point that we elaborate upon below: that the costs of partial CCS—already reasonable at the time of the 2015 Final Rule—would continue to decline as adoption increased. This follows the typical pattern for technology costs, which are highest for "first-of-a-kind" installations and decline for "next-of-a-kind" and more mature "Nth-of-a-kind" installations.[126] Amici conclude that CCS is already at the "next-of-a-kind" phase, and "the costs of implementation in power plant contexts are declining with each successive deployment."[127] EPA explicitly recognized this trend in the 2015 Final Rule when determining the costs of partial CCS to be reasonable for inclusion in the BSER.[128] Based on their analysis of historical trends for the costs of pollution-control technology, amici found it "reasonable to expect future CO_2 capture costs" to be "lower than those predicted by EPA" in the 2015 rule.[129] A recent feasibility study provided additional confirmation that that CCS costs have declined dramatically since the projects that EPA evaluated for the 2015 Final Rule.[130]

iii. Rollback of the 2015 Standard Will Hamper CCS Development

If the 2015 BSER promotes technological innovation, then the regressive nature of the proposed BSER could thwart it. EPA's proposal would yield a standard of performance even weaker than what many sources are already meeting today.

EPA repeatedly acknowledged the need to promote advanced technology throughout the rulemaking for the 2015 Final Rule. For example, in the Response to Comments, EPA provided, "As stated both at proposal and in the preamble to the final rule, promotion of technological innovation is a purpose of section 111 NSPS, and is grounded in the language of the statute, as well as in explicit legislative history."[131] EPA further stated, "As discussed at 79 FR 1465-66 and at III.H of the preamble to the final rule, the D.C. Circuit has held, with substantial support in the legislative history that an aspect of determining if a system of emission reduction is 'best' includes whether the system promotes technological innovation."[132] The superficial

[125] *Id.* at 64,575.
[126] *See* Brief of Amici Curiae Technological Innovation Experts, *supra* note 48, at 17. An excellent example is the capital and operating and maintenance costs of flue gas desulfurization scrubbers, which costs dropped dramatically in the decade flowing their initial (regulatory-mandated) deployment. History of FGD Use Memo, *supra* note 92, at unnumbered pp. 7, 9.
[127] Brief of Amici Curiae Technological Innovation Experts, *supra* note 48, at 18. The current Proposal makes a passing reference to "next-of-a-kind" costs, without analyzing their relevance to the BSER determination. Proposal, 83 Fed. Reg. at 65,447 n.97.
[128] 80 Fed. Reg. at 64,570-71 ("Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology.").
[129] Brief of Amici Curiae Technological Innovation Experts, *supra* note 48, at 21.
[130] *See Cost of Capturing CO2 Drops 67% for Next Carbon Capture Plant*, INTERNATIONAL CCS KNOWLEDGE CENTER (Nov. 28, 2018), https://ccsknowledge.com/news/cost-of-capturing-co2-drops-67-for-next-carbon-capture-plant.
[131] RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 2-29.
[132] *Id.* at 2-55.

consideration that EPA gives to technological innovation in the Proposal—a brief speculation about the possible international impact of the proposed BSER[133]—does not constitute a meaningful analysis and renders the Proposal arbitrary and capricious. EPA does not even compare the international impact of the proposed BSER to that of the 2015 BSER.

While the current Proposal includes a few references to the statute's goal of promoting advanced technology,[134] the agency does not meaningfully incorporate that goal into its decision-making. To the contrary, EPA attempts to wave away this required consideration through its "authority to weigh this against the other factors."[135] EPA then offers the unsupported speculation that, "[a]lthough supercritical technology is already developed, establishing it as the basis for control requirements in the U.S. for new and reconstructed sources would help establish it in other nations, resulting in a reduction in global CO_2 emissions."[136] EPA's purported concern for the effect of U.S. action on international climate mitigation efforts would support the adoption of more protective standards, not weakening the standards currently in place. Moreover, as explained below, EPA's proposed standards would allow *more* pollution than is being emitted by the average coal-fired generating unit in the European Union, China, and Japan.[137] Developers seeking to build efficient units in other countries would find better models than U.S. units meeting the proposed standard. The Proposal's glib discussion of international impacts provides no support for the agency's assertions that weakening the standards would lead to a "reduction in global CO_2 emissions," nor could the agency provide a plausible rationale as to why that would be the case.

EPA's reasoning, taken to its logical conclusion, implies that Congress's goal of promoting advanced technologies through a standard applying to new and modified sources is fulfilled as long as a standard of performance is better than the worst-performing *existing* units in the world, and—theoretically—some nations might therefore be inspired by the feeble BSER adopted here (though, inexplicably, not by the numerous examples of better-performing units both in the U.S. and abroad). For a Congress that aimed to improve air quality, that logic is implausible on its face, and it wholly ignores EPA's mandate to establish a BSER that incorporates pollution-reduction measures that are "adequately demonstrated" and "best" for the domestic sources that the agency regulates.

The Proposal utterly fails to address whether its BSER would promote technological innovation domestically. Indeed, the proposed BSER appears completely severed from any consideration of technologies that would allow the U.S. to help avert the worst impacts of climate change. The United States Mid-Century Strategy for Deep Decarbonization envisions a significant long-term potential for CCS, but not for fossil fuel-fired generation that does not capture its carbon pollution.[138] The Mid-Century strategy also notes that CCS in conjunction

[133] Proposal, 83 Fed. Reg. at 65,448.
[134] *E.g.*, *id.* at 65,434.
[135] *Id.* at 64,448.
[136] *Id.*
[137] Andover Technology Partners, New Source Performance Standards for Coal Steam EGUs, at 2 (Feb. 28, 2019).
[138] THE WHITE HOUSE, UNITED STATES MID-CENTURY STRATEGY FOR DEEP DECARBONIZATION 47 (2016), https://obamawhitehouse.archives.gov/sites/default/files/docs/mid_century_strategy_report-final.pdf ("Coal and natural gas power plants can continue to play a major role in the U.S. electricity system if their associated CO_2 emissions are captured and prevented from being released into the atmosphere.").

with certain forms of bioenergy offers an opportunity for negative emissions.[139] And it highlights the potential use of CCS in the industrial sector.[140] The Proposal does not discuss whether reversing the current BSER determination would prevent or discourage power companies from adopting CCS technologies that may provide the only path forward for fossil fuel-fired generation in a carbon-constrained world. Moreover, the Proposal fails to consider that CCS innovation for the power sector could have broader benefits by helping spur the deployment of CCS and driving reduced climate pollution across multiple sectors. The Clean Air Act, and section 111 in particular, embraces cross-sector fertilization of pollution-reduction opportunities.[141] It is arbitrary for EPA not to consider effects on future fossil fuel generation in a carbon-constrained world, and on other sectors, before rolling back the 2015 BSER. The proposed BSER would not promote technological innovation in the power sector, offers no benefits to other sectors, and does not fit into any plausible scenario for meaningfully mitigating climate change in the U.S. or abroad.

The Proposal's lack of meaningful analysis of the harmful impacts to technology advancement from selecting the proposed BSER reflects an unlawful failure to consider an important aspect of the issue.[142]

E. EPA's Revised Analysis Concluding that Partial Carbon Capture and Sequestration Is Too Costly Is Unreasonable and Arbitrary.

As discussed in detail below, the Proposal's conclusion that partial CCS is excessively costly to serve as the BSER for steam EGUs rests on a deeply flawed analysis, and is arbitrary and unlawful. To begin, the Proposal's conceptual framework for evaluating the costs of partial CCS is divorced from the statutory purpose of section 111 and manifestly unreasonable. Both the 2015 Final Rule and the Proposal recognize that new coal-fired steam EGUs are economically uncompetitive throughout the country and would only be contemplated for reasons unrelated to cost-competitiveness, such as fuel diversity. The 2015 Final Rule properly concluded that the costs of a new steam EGU with partial CCS are well within the range of other non-natural gas baseload resources that power companies rely on for fuel diversity, and therefore acceptable in light of the market realities facing coal. In contrast, the Proposal arbitrarily cites concerns about harming the competitive position of new coal-fired EGUs—despite the fact that no new coal-fired EGUs are likely to be built in competitive markets—as a reason to discard partial CCS as the BSER. This reasoning is internally inconsistent and, taken to its logical conclusion, would imply that *no* additional costs can be justified in assessing the BSER for new steam EGUs. This approach is not only arbitrary, it is contrary to EPA's obligation under section 111 to ensure that new sources of pollution minimize emissions to the "maximum practicable degree,"[143] and untethered from the case law holding that the costs of a BSER will be upheld so long as they are not "exorbitant" or greater than the industry can bear and survive.[144]

[139] *See id.*
[140] *See id.* at 65.
[141] *See, e.g., Lignite Energy Council*, 198 F.3d at 934.
[142] *State Farm*, 463 U.S. at 43.
[143] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 437 (D.C. Cir. 1973) (citing Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970, 116 Cong. Rec. 42384, 42385 (1970));
[144] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant."); *Portland Cement Ass'n. v. Train*, 513

The Proposal's reassessment of the costs of partial CCS is equally flawed and arbitrary. As we explain below, EPA uses unrealistic and unsupported assumptions about the costs of transport and storage of CO_2, and the anticipated capacity factor of CCS-equipped EGUs, to arbitrarily inflate the costs of a new steam EGU with partial CCS. Further, EPA arbitrarily ignores a range of factors that could substantially reduce the expected costs of new CCS-equipped EGUs—including continued learning effects resulting from ongoing deployment of CCS; the impact of the recently-expanded 45Q tax credit for carbon sequestration projects; and EOR revenues. And EPA arbitrarily invokes prior New Source Review permitting decisions rejecting CCS in project-specific circumstances that are legally and factually irrelevant to the question of whether partial CCS is the BSER for new steam EGUs.

i. EPA's Revised Cost Analysis Unreasonably and Arbitrarily Relies on the Current Uneconomic Status of New Coal-Fired Electric Generation to Justify Exempting Future Units from Critically Needed Greenhouse Gas Control Requirements.

A key piece of context, in determining what control costs are reasonable for the coal-fired EGU sector is that it is currently uneconomical to construct and operate a new coal-fired EGU, even without considering controls designed to reduce greenhouse gases. *See* Proposal, 83 Fed. Reg. at 65,427 (explaining that "recent EPA and EIA analyses project there to be, at most, few new, reconstructed or modified sources that will trigger the provisions EPA is proposing."); 2015 Final Rule, 80 Fed. Reg. at 64,563 ("Even in the absence of the standards of performance for newly constructed EGUs, substantial new construction of uncontrolled fossil steam units is not anticipated under existing prevailing and anticipated future economic conditions.").

Though new coal-fired EGUs are not economically competitive in current and projected future energy markets, EPA recognizes that such units may be built because "future realizations could deviate from these expectations as a result of changes in wholesale electricity markets, federal policy intervention, including mechanisms to incorporate value for onsite fuel storage, or substantial shifts in energy prices."[145] Furthermore, even if market conditions for new coal-fired electric generation remain unfavorable, EPA concludes that utilities may elect to construct new coal-fired EGUs to provide "fuel diversity."[146] Such diversity could serve "as a hedge against the possibility of natural gas prices far exceeding projections."[147] In sum, EPA indicates that it expects a new coal-fired EGU will be built only if market conditions change, or construction of a new coal-fired EGU provides some other benefit that justifies paying an above-market price for electricity.

Nonetheless, EPA now proposes to find that partial carbon capture and sequestration is too costly to qualify as BSER due primarily to the impact that the increased cost would have on

F.2d 506, 508 (D.C. Cir. 1975) (Court suggesting standards will be upheld unless "the costs of meeting standards would be greater than the industry could bear and survive.").

[145] Proposal, 83 Fed. Reg. at 65,427.

[146] *Id.* at 65,436.

[147] 2015 Final Rule, 80 Fed. Reg. at 64,513. An otherwise uneconomical coal-fired EGU may also be built to enable a company to "co-produce both power and chemicals, including capturing CO_2 for use in enhanced oil recovery (EOR) projects." *Id*. at 64,513-14.

"economic dispatch" of new coal-fired units under current energy market conditions, i.e., because controls would make coal-fired electricity more expensive, a new coal-unit would be dispatched less and therefore lower revenues would be realized.[148] Given that a new coal-fired EGU is already uneconomical absent a subsidy or some other offsetting benefit adding value to this generation apart from revenues, EPA's attempt to utilize those same existing market conditions to rule out partial carbon capture and sequestration —and in practice, *any* meaningful pollution control—without acknowledging its inconsistency or explaining why the additional costs of CCS are unreasonable is unlawful and arbitrary.

If a new coal-fired EGU's competitiveness in current energy markets were the benchmark for reasonable control costs under Clean Air Act section 111(a)(1), then the fact that construction of a new coal-fired EGU is already uneconomical would mean that *no* greenhouse gas control costs would be reasonable. Such outcome would be entirely inconsistent with Congress's intent for Clean Air Act section 111 to attain "elimination of new pollution problems" by ensuring that new sources are "controlled to the maximum extent possible to prevent atmospheric emissions."[149] Especially in light of Congress' express intent for Clean Air Act section 111 to regulate "power plants burning coal" so as "to prevent the occurrence anywhere in the United States of significant new air pollution problems arising from sources,"[150] EPA's selection of a cost analysis metric that automatically eliminates as too costly any significant greenhouse gas control requirement on new coal-fired EGUs is an unreasonable application of EPA's obligation under section 111 to prevent pollution from new power plants.[151]

When EPA promulgated its 2015 rule, it acknowledged the "unusual circumstances" under which "the record, and indeed simple consideration of electricity market economics, demonstrates that non-economic factors such as fuel diversity are likely to drive any construction of new coal-fired generation."[152] In particular, EPA's record only identified interest or consideration of new coal power in regulated energy markets that use an integrated resource planning process, not open energy markets where cost is the overriding decision factor and new coal plants cannot compete against natural gas-powered facilities.[153] Accordingly, EPA developed a cost analysis metric under which it "reject[ed] more stringent options that would impose potentially excessive costs," but took into account that "higher costs can be viewed as reasonable when costs are not a paramount factor in new coal capacity decisions."[154] Significantly, EPA rejected using coal's competitiveness with natural gas as a metric for considering costs because even in the absence of the new rule, power providers "considering costs alone" would choose natural gas over coal for new intermediate or baseload generation due to the "competitive current and projected price" of natural gas.[155] Instead, EPA reasonably considered costs when setting the 2015 standard by assessing how much a power provider would

[148] Proposal, 83 Fed. Reg. at 65,438.
[149] S. Rep. No. 91-1196, at 12.
[150] H. Rep. No. 91-1146 (1970).
[151] *See also id.* (identifying "electric generating plants" as facilities that "must be controlled to the maximum practicable degree regardless of their location and industrial operations" and declaring that "implicit consideration of economic factors in determining whether technology is 'available' should not affect the usefulness of this section.").
[152] 2015 Final Rule, 80 Fed. Reg. at 64,559.
[153] *Id.*
[154] *Id.*
[155] *Id.* at 64,563.

be willing to pay for "fuel diversity," and the percentage by which the use of carbon capture and sequestration technology would increase the capital cost of a new coal-fired EGU.[156]

Now, though EPA's view of the uneconomical nature of new coal-fired EGUs remains unchanged, EPA declares that its failure to account for "economic dispatch" in its 2015 analysis was erroneous. According to EPA, "[i]n deregulated markets, a new coal-fired EGU must compete directly against all other forms of generation, including existing coal-fired EGUs and natural gas combined cycle units," and consideration of economic dispatch impacts in its cost analysis is "a more refined representation of the BSER determination."[157] But EPA certainly was aware of the concept of "economic dispatch" when it promulgated the 2015 NSPS.[158] Thus, EPA's 2015 decision not to consider how its BSER determination would impact economic dispatch was not an oversight. EPA appropriately chose not to consider the impact of increased control costs on a coal-fired EGU's competitiveness in de-regulated energy markets vis-à-vis natural-gas-fired units because EPA recognized that this is not the factor driving a power supplier's decision to construct a new coal-fired EGU.[159]

In contrast, EPA now unreasonably rejects partial CCS on concerns regarding its competitiveness in deregulated markets—despite the dearth of evidence that a new coal power plant would be built in a deregulated market in the first place. Notably, the proposed rule never articulates any cost concerns in the context of a regulated market.

Contrary to EPA's assertion, EPA's attempt to integrate "economic dispatch" into its cost analysis is not a "refine[ment]" of its original analysis.[160] Rather, EPA's new proposal would reverse the agency's 2015 determination that because coal-fired EGUs already are not competitive with natural gas-fired EGUs, such cost-competitiveness is not a relevant cost metric for determining whether control costs are reasonable. Yet, EPA fails to explain why it now views cost-competitiveness vis-à-vis natural-gas fired EGUs as relevant. Notably, EPA concedes "that the projections it made in conjunction with its promulgation of the 2015 rule remain generally correct,"[161] and that "current utility forecast models continue to project that few, if any, new coal-fired power plants will be built in the U.S. in the subsequent decade."[162] EPA says nothing to refute its 2015 conclusion that new coal-fired EGUs are not competitive with natural gas-fired EGUs under current and anticipated market conditions and that "non-economic factors such as a desire for fuel diversity will likely drive future development of any coal-fired EGUs."[163] EPA's failure to offer a reasoned explanation for its changed position regarding the relevance of cost-competitiveness with natural gas-fired EGUs to its BSER selection renders its proposal arbitrary and unlawful. *See, e.g.*, *State Farm*, 463 U.S. at 56–57 (agency "must supply a reasoned analysis" to support changed position) (internal citations omitted).

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[156] *Id.* at 64,560.
[157] Proposal, 83 Fed. Reg. at 65,438–39.
[158] *See, e.g.*, 2014 Proposed Rule, 79 Fed. Reg. at 34,862 (considering "economic dispatch" when proposing carbon standards for existing EGUs).
[159] *See* 2015 Final Rule, 80 Fed. Reg. at 64,559; *see also id.* at 64,569 (reiterating that "no steam electric EGU would be cost competitive even without [coal capture and sequestration].").
[160] Proposal, 83 Fed. Reg. at 65,439.
[161] *Id.* at 65,427.
[162] *Id.* at 65,436.
[163] 2015 Final Rule, 80 Fed. Reg. at 64,596.

Equally without merit is EPA's argument that it can reject carbon capture and sequestration as BSER because it would make new coal-fired EGUs uncompetitive with existing coal-fired EGUs.[164] First, though EPA asserts that requiring new coal-fired EGUs to utilize carbon capture and sequestration would cause too much disparity between the cost of operating a new, well-controlled EGU versus the cost of operating an existing uncontrolled coal-fired EGU, this problem would only arise if EPA abdicated its authority (and in fact, its legal responsibility) to effectively regulate existing sources. Specifically, where EPA promulgates a standard of performance for *new* sources that addresses a pollutant that is not a criteria pollutant or a hazardous air pollutant under Clean Air Act section 112, EPA is required to regulate emissions of that same pollutant from *existing* sources. That statutory requirement addresses exactly the concern that EPA raises here: that existing coal-fired EGUs typically employ no greenhouse gas controls because "unlike other environmental controls, there is limited regulatory requirements or incentive to reduce GHG emissions aside from the NSPS requirements."[165] EPA cannot rely on its failure to properly implement Clean Air Act 111(d) as its basis for refusing to require new coal-fired EGUs to employ effective greenhouse gas controls pursuant to Clean Air Act section 111(b). Such an outcome plainly would contravene Congress' intent to require "[t]he maximum use of available means of preventing and controlling air pollution" in order to "eliminat[e] … new pollution problems while cleaning up existing sources."[166]

Another reason, EPA's claim that selecting carbon capture and sequestration as BSER would make new coal-fired EGUs uncompetitive with existing coal-fired EGUs is meritless is because, as EPA concedes, even if new coal-fired EGUs were economically competitive with existing coal-fired EGUs, they still would not be competitive with natural gas-fired EGUs. Thus, competitiveness with existing coal-fired EGUs plainly is not the driver in any determination as to whether to construct a new coal-fired EGU. Rather, as explained in EPA's 2015 rulemaking and not refuted by EPA in its new proposal, a decision to construct a new coal-fired EGU would be driven by *non-economic* factors.[167] Indeed, while EPA concedes that the primary such factor would be a power producer's desire to achieve fuel diversity, EPA admits that its concern regarding competitiveness with existing coal-fired EGUs would arise "in markets with significant quantities of coal-fired generation"[168]—in other words, in markets where adding a new coal-fired EGU would do nothing to promote fuel diversity. Thus, even if EPA's concern regarding a new coal-fired EGU's competitiveness with existing coal-fired EGUs was a relevant metric for its BSER cost analysis—which it is not—EPA's concerns are unlikely to be realized because it is unlikely that an uneconomical coal-fired EGU would be constructed where a significant percentage of electricity is already generated from coal.

Ultimately, it is EPA's responsibility to elucidate a non-arbitrary methodology for considering costs when promulgating a standard of performance under Clean Air Act § 111(b). While EPA has wide discretion in selecting an appropriate cost analysis methodology, "consideration of economic factors in determining whether technology is 'available' should not

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[164] Proposal, 83 Fed. Reg. at 65,439.
[165] *Id.* at 65,439 n.73.
[166] S. Rep. No. 91-1196, at 12.
[167] *See* 2015 Final Rule.
[168] Proposal, 83 Fed. Reg. at 65,439.

affect the usefulness of [Section 111].”[169] Here, where construction of a new source in the regulated category would be unjustified but for consideration of factors other than cost-competitiveness, it is fundamentally unreasonable for EPA to select a cost metric that turns on whether increased control costs would make new sources even more economically uncompetitive without explaining why that factor is relevant or comparing additional costs to other generation sources that provide fuel diversity. Use of this cost metric arbitrarily disregards the factors that EPA itself has determined would drive a decision to construct a new coal-fired EGU and contravenes Congress’s intent by making virtually any control costs appear to be unreasonable.

Further—and at a more basic level—nowhere in the Clean Air Act is EPA authorized to evade its responsibility to address air pollution that endangers human health and welfare in order to advantage or preserve a method of production that is higher emitting than alternative methods of production of the same product. To the contrary, the directive of Congress in Section 111 is for EPA to identify the “best system of emission reduction”—which should advantage and deploy methods of producing a product that are lower emitting than alternative methods. In this instance, the clear outcome of this statutory directive is the identification of carbon capture as a best system of emission reduction. Citing the need to preserve coal generation without greenhouse gas pollution controls as a reason to weaken the existing standards of performance when pollution controls exist as do alternative, lower-emitting methods of generating electricity reflects the agency’s fundamental rejection of its obligations under the Act.

ii. EPA’s Suggestion that Nuclear and Biomass Are Not Appropriate Benchmarks in Evaluating the Cost of Partial CCS is Arbitrary and Capricious

In 2015, EPA compared the levelized cost of electricity from coal-fired EGUs equipped with partial CCS with that of nuclear plants. The agency noted that “[t]he utility industry and electricity sector regulators often use levelized costs as a summary measure for comparing the cost of different potential generating resources,” and that “[u]se of the LCOE as a comparison measure is appropriate where the facilities being compared would serve load in a similar manner.”[170] This rationale for comparing LCOEs is supported by the case law interpreting CAA section 111, and is consistent with the real-world practice of power companies.

The D.C. Circuit has explained that Congress intended that EPA secure the greatest quantity of emission reductions feasible without imposing an exorbitantly costly standard on the regulated industry.[171] Although the relevant industry here is the electric power sector, EPA has developed a standard tailored for coal-fired EGUs. Because power companies themselves consider the LCOEs of different generating resources when making investment decisions, and because both coal-fired and nuclear generation provide baseload power and are close substitutes that may directly compete with each other both in power markets and as potential investments by

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[169] S. Rep. No. 91-1196, at 12.
[170] 2015 Final Rule, 80 Fed. Reg. at 64,561.
[171] *See Lignite Energy Council*, 198 F.3d at 933 (“EPA’s choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.”); *Portland Cement Ass’n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975) (noting EPA’s decision not to impose costs that were “greater than the industry could bear and survive”); *Essex Chem. Corp.*, 486 F.2d at 437 (noting Congress’s “intent that new plants be controlled to the ‘maximum practicable degree’”).

power companies, it would be reasonable for EPA to compare the LCOE of coal-fired generation with partial CCS to that of nuclear generation (as it did in the 2015 Final Rule).

Beyond providing baseload power, the record for the 2015 Final Rule and more recent information confirm that other commonalities between coal-fired and nuclear generation further justify comparing their LCOEs in assessing the costs of the BSER. Power companies regard both coal and nuclear power as enhancing fuel diversity in their resource mix, and have acknowledged the value they place on fuel diversity in recent integrated resource plans submitted to state regulators. For example, Georgia Power Company observed that its new nuclear units would "bring needed base load capacity *and even greater fuel diversity and energy benefits* to the Company's fleet."[172] Similarly, it argued in a discussion of controls and upgrades for its coal-fired generation units that this resource is a "reliable part of the fleet, maintaining essential fuel diversity."[173] Tucson Electric Power Company envisioned replacing coal-fired generation with small nuclear reactors because "coal and nuclear resources provide the same service (fully dispatchable load serving resources), and [nuclear generation is] a means of *maintaining some resource diversity in the absence of coal-fired generation*."[174] Thus, at least some power companies view coal-fired and nuclear generation as close substitutes in providing fuel diversity, and it was therefore appropriate for EPA to compare the LCOEs of these resources when conducting its BSER analysis for coal-fired power plants in 2015.[175]

Relatedly, utilities have argued that coal-fired and nuclear generation offer a hedge against potential volatility in the prices of other fuels. Georgia Power asserted in its plan that well-controlled coal-fired EGUs would "position[] [the company] to be able to respond to future increases or volatility in the cost of natural gas."[176] South Carolina Electric & Gas Company has likewise pointed to nuclear energy as having benefits in terms of price stability.[177] Likewise, when Florida Power & Light received an operating license in 2018 from the Nuclear Regulatory Commission to construct two new reactors at Turkey Point, company representatives said, "We felt this was an important thing for our customers all along. It gives us an option. . . . It is very important for us to have diverse sources of fuel. Nuclear is very stable in terms of fuel prices."[178] EPA correctly noted this common feature of coal and nuclear power when comparing the LCOEs of a nuclear power plant and a coal-fired EGU with partial CCS in 2015.[179]

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[172] GEORGIA POWER CO., GEORGIA POWER COMPANY'S 2013 INTEGRATED RESOURCE PLAN AND APPLICATION FOR DECERTIFICATION OF PLANT BRANCH UNITS 3 AND 4, PLANT MCMANUS UNITS 1 AND 2, PLANT KRAFT UNITS 1-4, PLANT YATES UNITS 1-5, PLANT BOULEVARD UNITS 2 AND 3, AND PLANT BOWEN UNIT 6 at 1-8 (2013) (emphasis added) [hereinafter Georgia Power IRP].
[173] *Id.* at 1-18.
[174] TUCSON ELECTRIC POWER, TUCSON ELECTRIC POWER COMPANY'S 2017 INTEGRATED RESOURCE PLAN 273 (2017) (emphasis added).
[175] 2015 Final Rule 80 Fed. Reg. at 64,563.
[176] Georgia Power IRP, *supra* note 172, at 1-7.
[177] SCE&G, Combined Application for Certificate of Environmental Compatibility, Public Convenience and Necessity and for a Base Load Review Order for the Construction and Operation of a Nuclear Facility at Jenkinsville, South Carolina, Ex. H, at 7 (2008).
[178] Susan Salisbury, *NRC to Issue License for Two New Reactors at Turkey Point*, THE PALM BEACH POST (Apr. 5, 2018), https://www.palmbeachpost.com/news/nrc-issue-license-for-two-new-reactors-turkey-point/A7xO1JMcLKGxFwbwkTTxXL/.
[179] 2015 Final Rule, 80 Fed. Reg. at 64,563.

Thus, although power companies are not currently developing new coal-fired EGUs because of the availability of more cost-competitive alternatives, any power company that did consider a new coal-fired power plant would likely do so on the basis of fuel diversity, price hedging, ability to operate as a baseload source, and related considerations. EPA appropriately recognized in the 2015 Final Rule that power companies would likely consider nuclear generation as an alternative for the same reasons.

Against the available evidence, EPA's new attempt to distinguish nuclear generation as an inappropriate cost comparator for a new coal-fired power plant falls flat. Although the agency correctly recognizes that nuclear generation results in lower air pollution than coal-fired EGUs with partial CCS,[180] the Proposal provides no evidence as to how that impacts power companies' evaluations of the LCOE of these two resources.

Further, EPA overlooks that there are potential unpriced costs associated with nuclear generation which might offset any premium associated with lower air emissions, such as costs associated with waste disposal and decommissioning. Some of these risks may be priced into nuclear generation through insurance premiums or may be ameliorated through the promise of indemnities from the federal government under the Price-Anderson Act.[181] Nevertheless, to the extent that EPA considers the environmental attributes of potential substitute generation resources in its cost analysis, it cannot credit the fact that nuclear generation is zero-emitting and simultaneously ignore the potential costs of nuclear generation. It would be arbitrary to rule out nuclear generation for purposes of cost comparison based on its environmental savings over coal-fired generation without also considering its costs.

In addition, EPA's decision in 2015 to compare the LCOE of new biomass and new coal-fired generation with partial CCS was reasonable, because biomass EGUs are another form of non-natural gas baseload generation.[182] The Proposal dismisses that comparison because "[b]iomass-fired EGUs are smaller in scale and not as closely analogous to coal-fired generation as is nuclear power."[183] EPA's rationales for reversing its position are arbitrary. First, EPA's claim that the largest biomass-fired EGU outside the U.S. is less than 300 MW is incorrect: the Drax power station in the United Kingdom, for example, has multiple biomass-fired generating units with a combined capacity of 2.6 GW.[184] In addition, the United Kingdom's Ironbridge power station was converted from coal to biomass in 2012, and operated entirely on biomass with a generating capacity of 740 MW until it ceased operations in 2015.[185] These examples show that large biomass-fired power stations are feasible to operate and provide energy services comparable to coal-fired power plants.

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[180] Proposal, 83 Fed. Reg. at 65,437 ("Nuclear projects have no emissions of criteria pollutants, hazardous air pollutants (HAPs), or GHGs.").
[181] *See Duke Power Co. v. Carolina Envtl. Study Grp.*, 438 U.S. 59, 64–65 (1978).
[182] 2015 Final Rule, 80 Fed. Reg. 64,562 n.276.
[183] Proposal, 83 Fed. Reg. at 65,473 (footnote omitted).
[184] Gaurav Sharma, *Utility of Agility: Drax Group Boss Plots Coal-Free Future for £1.5b U.K. Energy Outfit*, FORBES (Aug. 30, 2018), https://www.forbes.com/sites/gauravsharma/2018/08/30/utility-of-agility-drax-group-boss-plots-coal-free-future-for-u-k-energy-outfit/#37208bb01d37.
[185] Emily Gosden, *Ironbridge Power Plant Shut Down After 46 Years*, THE TELEGRAPH (Nov. 20, 2015), https://www.telegraph.co.uk/finance/newsbysector/energy/12008878/Ironbridge-power-plant-shut-down-after-46-years.html.

EPA's basis for dismissing the relevance of biomass EGUs is also in tension with the agency's claim that fuel diversity from nuclear generation is enhanced by its high capacity factor (and therefore higher dispatch).[186] The fact that biomass-fired EGUs are smaller than most other EGUs similarly suggests that coal-fired EGUs with partial CCS would provide greater fuel-diversity benefits through higher dispatch (and therefore be worthwhile to power companies at a higher LCOE) than biomass-fired EGUs. Whatever the merits of EPA's reasoning, it cannot rationally amplify the non-economic benefits of nuclear generation by considering nuclear's higher capacity factor and disregard the similar advantage that coal-fired generation has over biomass-fired generation by virtue of its higher average level of dispatch.

iii. Comparison with Nuclear and Biomass, Even with the Proposal's Improperly Inflated Cost Estimates, Demonstrates that Partial CCS is Reasonable Cost

If EPA uses the LCOE of either nuclear or biomass generation as a benchmark, as it did in the 2015 Final Rule, the agency must find the costs of partial CCS to be eminently reasonable *even using* the arbitrarily inflated cost estimate that is presented in the Proposal. The Proposal estimates that the LCOE associated with a supercritical pulverized coal EGU equipped with partial CCS is \$105.40/MWh,[187] after adjusting the assumptions for transportation costs, storage costs, and capacity factor that were utilized in the 2015 Final Rule. As explained in the subsequent section of these comments, this new estimate of the LCOE arbitrarily overstates the costs of partial CCS. Nonetheless, even this inflated cost estimate falls squarely within the range of current LCOEs for nuclear and biomass generation: according to the Proposal, LCOEs range from \$87-132/MWh for nuclear generation and from \$87-116/MWh for biomass generation.[188] It would be arbitrary for EPA to determine that partial CCS is not the BSER when its own estimate of the costs of CCS falls within the range of other non-natural gas baseload technologies that can substitute for coal.

iv. EPA's New Determination that the Costs of CCS Are Unreasonable Overstates the Costs of CCS and is Arbitrary and Capricious

EPA's reassessment of CCS costs in the Proposal involves adjustments to transportation and storage costs and capacity factors that are arbitrary and capricious and only serve to inflate costs. As we discuss in detail below, EPA relies on outdated cost data for transportation instead of using more recent estimates that better reflect the pipeline infrastructure for CCS capture. EPA also adopts the unrealistic assumption that each source of CO_2 will be paired with a single CO_2 storage location, instead of using the more reasonable assumption—supported by industry trends—that a proven geologic storage site would serve multiple sources of CO_2. This in turn drives up the per ton cost of storage. Finally, EPA adjusts its capacity factor assumption for a new coal-fired EGU with partial CCS downwards, arguing that higher costs due to CCS lead to a

[186] *See* Proposal, 83 Fed. Reg. at 65,437 ("[T]he incremental generating costs for nuclear projects are lower than those for coal-fired EGUs, thus, nuclear EGUs would be expected to provide more actual non-natural gas generation per amount of installed capacity.").
[187] *Id.* at 65,439.
[188] *Id.* at 65,436–37.

lower spot on the dispatch curve and hence lower capacity factor. Not only are EPA's assumptions of changes in dispatch order and reduced capacity factors unreasonable, but there are also several significant flaws in the agency's methodology that make its analysis arbitrary and capricious. Together, the combination of transportation and storage inflated cost adjustments and unsupported changes in capacity factor have the effect of increasing the final LCOE for new coal-fired EGUs with partial CCS by roughly 10%, with 75% of this increase due to the change in capacity factor.

1. EPA's Adjustments to Transportation and Storage Costs and Capacity Factors Artificially Inflate Costs

EPA uses an amended LCOE for new coal-fired EGUs with CCS based on adjustments it makes to the transportation and storage (T&S) costs and capacity factors used in the 2015 Final Rule. In the 2015 Final Rule, EPA relied on a fixed T&S cost for geologic storage of $11 per metric ton of CO_2.[189] EPA now proposes to adjust the T&S cost based on the amount of CO_2 captured using transport and saline storage cost models developed by the National Energy Technology Laboratory (NETL).[190] As shown in Table 1, using this new methodology, EPA estimates that costs increase substantially on a dollar per metric ton basis as the amount of CO_2 captured decreases.[191] According to EPA, T&S costs for a 16% CCS capture rate (which is the basis for the existing standard) would reach $29 per metric ton.[192] As shown in Figure 1, this translates to an increase in the final LCOE of $2.4/MWh, or about 2.5%, at 16% capture rate.

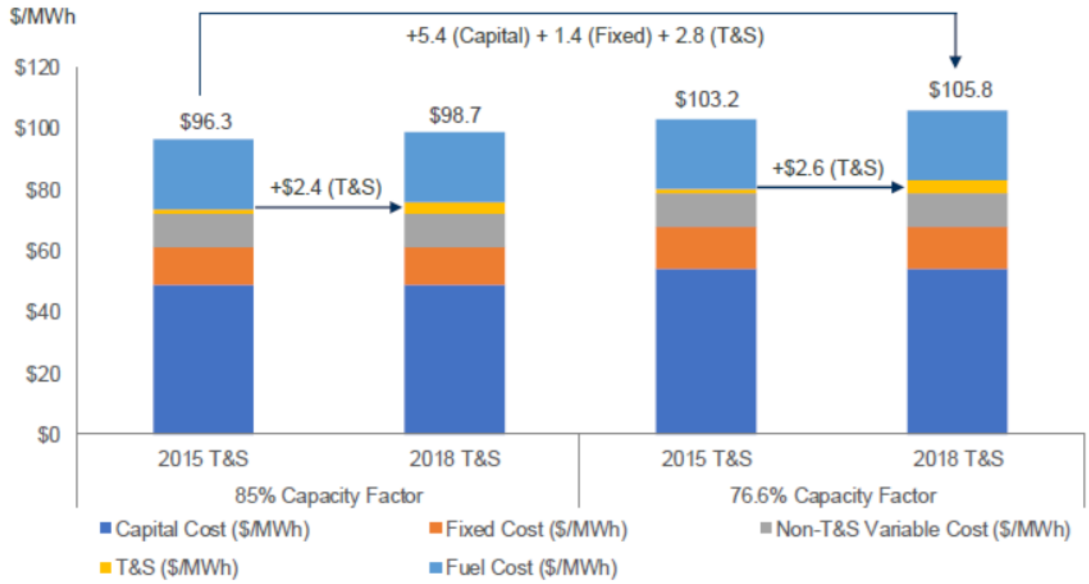
Table 1: EPA Transportation and Storage Costs[193]

Capture Rate	CO_2 Captured per Year (million metric tons)	Total T&S Cost (2016$ per metric ton)	Total T&S Cost (2016$ per MWh)
90%	4.2	9.6	8.4
72%	3.2	11	7.1
60%	2.6	12	6.2
48%	2.0	13	5.6
35%	1.4	16	4.8
16%	0.62	29	3.7

In addition to the adjustments to T&S costs, EPA also uses a lower capacity factor of 76.6% compared to its original 85% capacity factor. Without changing the T&S assumption, the capacity factor change increases the LCOE by $6.9/MWh or 7.2%. As shown in Figure 1, the combination of the T&S and the capacity factor change have the effect of increasing the final LCOE for new coal-fired EGUs with 16% CCS by $9.5/MWh or 9.9%. Of the $9.5/MWh increase, about 75% is the result of the change in capacity factor.

189 *Id.* at 65,438.
190 *Id.*
191 *Id.*; *see also* CO_2 Transport and Storage Costs (NETL Model) Technical Support Document available in EPA NSPS Proposal docket.
192 Proposal, 83 Fed. Reg. at 65,438.
193 *Id.*

Figure 1: Impact of Changing T&S Costs and Capacity Factor on LCOE[194]



a. *EPA's Assumptions on Transportation and Storage Overstate Costs*

When estimating transportation costs, EPA relies on costs drawn from a 2004 study by Parker.[195] Using the NETL transport model, EPA estimates a transportation cost of roughly $7 per metric ton at a 16% capture rate. However, as shown in Figure 2, using more recent 2011 costs by Rui as input in the NETL transport model yields lower transportation costs—less than $5 per metric ton at a 16% capture rate.[196] Rui's estimates are based on more recent cost data and therefore better reflect the pipeline infrastructure for CCS capture.[197]

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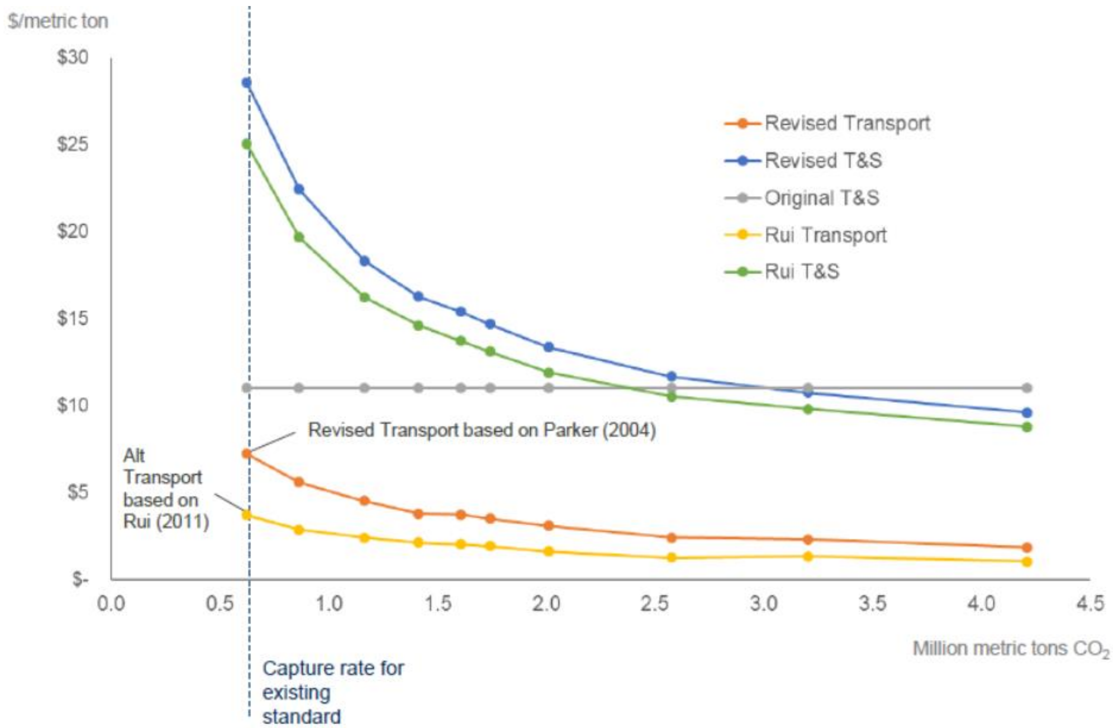
[194] Calculated using NAT. ENERGY TECH. LAB. & DEP'T OF ENERGY, COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS SUPPLEMENT: SENSITIVITY TO CO2 CAPTURE RATE IN COAL FIRED POWER PLANTS (2015).

[195] *See* NAT. ENERGY TECH. LAB., QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES: CARBON DIOXIDE TRANSPORT AND STORAGE COSTS IN NETL STUDIES 11 (2017).

[196] *See* NAT. ENERGY TECH. LAB., QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES: CARBON DIOXIDE TRANSPORT AND STORAGE COSTS IN NETL STUDIES (2017).

[197] EPA must of course account for new information and use best information available if it is to engage in reasoned decision-making. *See, e.g.*, *Catawba Cnty. v. EPA*, 571 F. 3d 20, 45 (D.C. Cir. 2009).

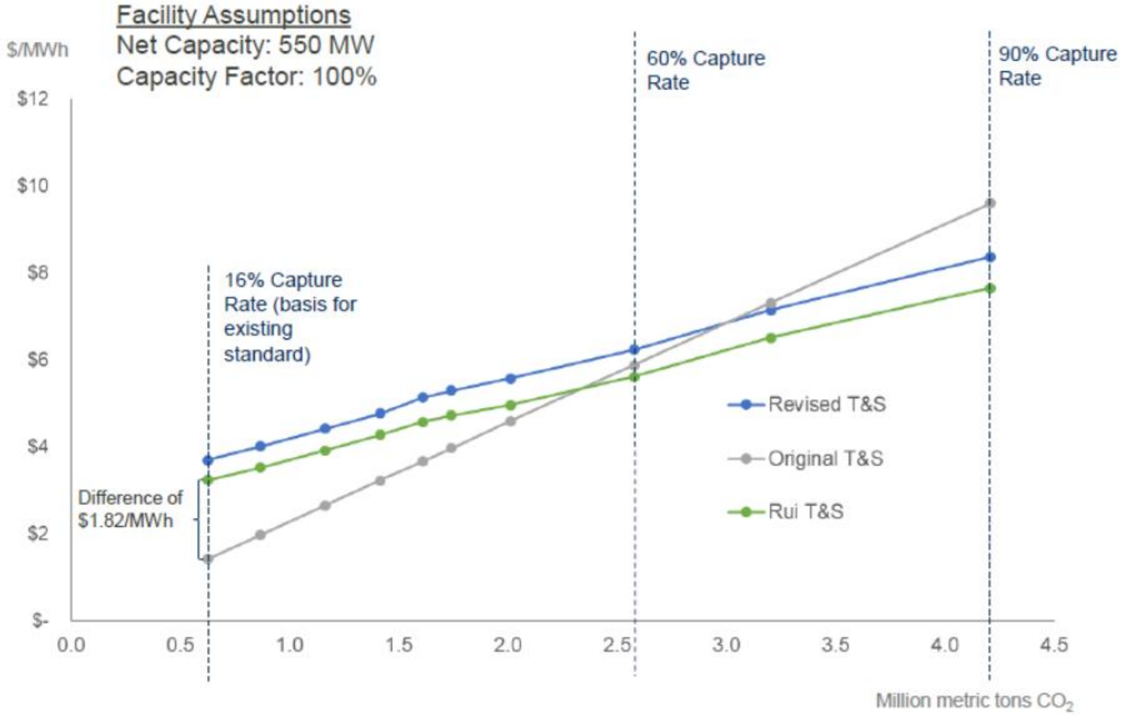
Figure 2: Estimated T&S Costs ($ per metric ton)[198]



As shown in Figure 3, this translates to a $0.45/MWh reduction in the costs reported in the Proposal for a new coal-fired EGU with 16% capture rate.

[198] *See* NAT. ENERGY TECH. LAB., QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES: CARBON DIOXIDE TRANSPORT AND STORAGE COSTS IN NETL STUDIES (2017) (assuming facility with 550 MW net capacity and 100% capacity factor).

Figure 3: Estimated T&S Costs ($/MWh)[199]



For storage costs, EPA assumes that each source of CO_2 will be paired with a single CO_2 storage location, rather than utilizing the more realistic assumption that a proven geologic storage site will accept captured carbon from multiple sources. EPA's assumption that each storage location will be paired with one and only one source drives up the per ton cost of storage by assigning all the costs associated with storage to a single CO_2 source. Of the capital costs and expenses NETL estimates for storing 0.62 million metric tons of CO_2, 17% do not scale with increasing volumes. These non-scaled costs include costs associated with reporting, stratigraphic test wells, and groundwater and vadose zone monitoring wells, which should be distributed across all the sources that are using the storage location.[200]

A far more reasonable storage assumption is to assume that a new coal-fired power plant with partial CO_2 capture will be just one of multiple sources delivering captured CO_2 to a storage location. Indeed, there are a number of ongoing trends within the industry that point toward the development of storage networks or hubs in the coming years, which would serve multiple sources of CO_2. For instance, there are several ongoing initiatives to develop CO_2 storage hubs:

- Project ECO2S is a collaboration working to develop a significant storage location adjacent to Mississippi Power's Kemper County energy facility in

[199] *Id.*
[200] In total, $51 million of capital costs and expenses are the same for storing the 0.62 million metric tons of CO_2 as they would be for storing 3.2 million metric tons of CO_2.

Mississippi.[201] The researchers have estimated costs of \$2 to \$4 per metric ton of CO_2 stored.[202]

- In May 2018, DOE announced the selection of three projects to inform the characterization and permitting of commercial-scale CO_2 storage facilities as part of Phase II of the CarbonSAFE initiative, part of DOE's Carbon Storage Program. These projects were selected from 13 projects funded in 2016 to study the pre-feasibility of storage complexes. The goal of CarbonSAFE is to develop hubs that can provide CO_2 storage services to multiple industrial and power sector sources of CO_2.[203] The three projects funded for Phase II include:
    - The Integrated Midcontinent Stacked Carbon Storage Hub, which has identified industrial and electric power facilities as potential sources of CO_2 for a facility in Kansas
    - Wabash CarbonSAFE, which is working to establish the feasibility of developing a commercial-scale geological storage complex at the Quasar Syngas LLC's Wabash Integrated Gasification Combined Cycle plant
    - Commercial-Scale Carbon Storage Complex Feasibility Study at Dry Fork Station, Wyoming – University of Wyoming (Laramie, WY), which aims to determine the feasibility of establishing a commercial-scale geological storage complex in Wyoming's Powder River Basin in the immediate vicinity of Basin Electric Power Corporation's Dry Fork Power Station

In addition to the above initiatives, the 45Q tax credits are expected to incentivize increased CCS deployment, further expanding storage options. According to a recent study by the Clean Air Task Force, the 45Q tax credits are expected to result in capture and storage of 49 million metric tons of CO_2 annually in 2030.[204] The development of storage locations to serve that demand would further lower storage costs for all CCS projects through learning and economies of scale. There is also the potential for CO_2 storage locations to develop to serve industrial sectors that could also be accessed by the power sector, for instance the potential for CCS at biorefineries to take advantage of credits from existing low-carbon fuel policies.[205]

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[201] DOE National Energy Technology Laboratory, Establishing An Early Carbon Dioxide Storage (ECO2S) Complex in Kemper County, Mississippi: Project ECO2S, Project Information (accessed March 6, 2019), https://www.netl.doe.gov/project-information?p=FE0029465.

[202] Riestenberg, David, Southern State Energy Board, CarbonSAFE: Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi: Project ECO2S, presentation at 2018 Carbon Storage and Oil and Natural Gas Technologies Review Meeting (August 2018), https://www.netl.doe.gov/projects/files/D-Riestenberg-CarbonSAFE-Project-ECO2S.pdf.

[203] DOE Office of Fossil Energy, Energy Department Selects Additional Carbon Storage Feasibility Projects to Receive Nearly \$30M in Federal Funding, Press Release (May 24, 2018), https://www.energy.gov/fe/articles/energy-department-selects-additional-carbon-storage-feasibility-projects-receive-nearly.

[204] Nagabhushan, Deepika and John Thompson, Clear Air Task Force, Carbon Capture & Storage in the United States Power Sector: The Impact of the 45Q Federal Tax Credits (February 2019), https://www.catf.us/wp-content/uploads/2019/02/CATF_CCS_United_States_Power_Sector.pdf.

[205] *See* Sanchez et al., *Near-Term Deployment of Carbon Capture and Sequestration from Biorefineries in the United States*, 115 PNAS 4875, 4879 (2018).

Existing coal-fired power plants with CCS such as Petra Nova and Boundary Dam have also taken advantage of enhanced oil recovery (EOR) opportunities. It is therefore reasonable to expect new coal-fired power plants installing CCS to look for similar opportunities to commodify captured CO_2 as opposed to developing new, dedicated storage locations.

If EPA were to adopt the reasonable and data-backed assumption that multiple sources could deliver captured CO_2 to a storage location when estimating storage costs—and would be expected to do so because by doing so they could significantly lower overall costs—it would find that the costs of storage are far lower than estimated in the Proposal. For instance, if EPA were to assume that each storage site were associated with just 2.6 facilities equivalent in size to EPA's model plant (capturing a collective total of 2.6 million metric tons CO_2 per year), its estimated cost of storage per metric ton would decline by 57%.[206] If EPA were to assume 4.2 such facilities per storage site, storage costs would be 64% lower.[207] Using such an approach for storage costs together with the lower transport costs based on Rui, T&S costs would decline from $28.57 per metric ton CO_2 to $11.46 to $12.97 per metric ton, assuming annual storage of 4.2 or 2.6 million metric tons CO_2, respectively. This is close to EPA's 2015 T&S cost of $11 per metric ton.

b. *EPA's Capacity Factor Adjustments Are Unreasonable and Inflate Costs*

EPA argues that higher costs resulting from partial CCS at new coal-fired EGUs lead to a lower spot on the dispatch curve and therefore a lower capacity factor.[208] EPA finds that capacity factors for coal-fired EGUs decrease by approximately 1.5% for each $1/MWh increase in variable operating costs.[209] Accordingly, EPA adjusts its original capacity factor assumption of 85% for a new coal-fired EGU with partial CCS to 76.6%.[210] As mentioned above, this adjustment contributes to 75% of the increase in the final LCOE.

First, EPA's assumptions of changes in dispatch order and reduced capacity factors are unreasonable since, as evidenced by the agency's own record, no one would build a new coal plant in a competitive market under current market conditions or based on economics alone. Indeed, EPA's reliance on fuel diversity as a reason why coal plants might be built is currently only supported with respect to regulated markets and cannot be reconciled with dispatch order concerns. In fact, in its calculation of the LCOE for new coal-fired EGUs with CCS (ranging from 30% to 90% CCS), the U.S. Energy Information Administration (EIA) assumes a capacity factor of 85%—consistent with EPA's original 2015 assumption.[211] EPA provides no evidence that any new coal plant would be built in a deregulated market context and in a regulated market, the utilities' economic dispatch order would not govern the construction decision. Rather the construction decision would be made through an Integrated Resource Plan where EPA's record

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[206] *See* NSPS Economic Impact Analysis at 2-4 tbl. 2-1 (showing 1.1 million short tons per year CO_2 emission reduction from new coal-fired EGU of 600 MW net capacity with partial CCS compared to no CCS).
[207] *Id.*
[208] Proposal, 83 Fed. Reg. at 65,439.
[209] *Id.*; *see also* Memorandum from EPA on Impact of Variable Operating Costs on Capacity Factors for Coal-Fired Electric Generating Units, at 2 (December 2018) [hereinafter Memo on Variable Operating Cost Impacts].
[210] Proposal, 83 Fed. Reg. at 65,439.
[211] *See* ENERGY. INFO. ADMIN., LEVELIZED COST AND LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 2019, at 8 tbl.1b (2019), https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

shows fuel diversity would be the motivating justification and the utility would be guaranteed a rate of return assuming high utilization of that plant.

Further, there are several significant flaws in EPA's methodology that render the agency's analysis arbitrary and capricious:

- *Regional supply curve differences are not reflected*. EPA's analysis does not account for any differences in the operational characteristics of regional electricity systems. U.S. electricity markets in which EGUs compete to supply electricity are regional and sub-regional in nature. By grouping all U.S. coal-fired EGUs units together in one group, EPA's regression method fails to account for any regional differences including steepness of supply curves, fuel costs, etc., which largely determine whether and to what extent generating output of any EGU is affected as its variable costs go up or down.

- *EGUs with increased costs not redispatched.* EPA did not carry out a full redispatch of the U.S. electricity system, with coal-fired EGUs reflecting their increased (due to CCS) variable costs, before running its regression analysis. Instead, EPA used the coal-fired units' estimated current variable costs, which do not include any CCS-related costs, and capacity factors based on EIA data. This means that EPA's regression analysis did not reflect output changes due solely to incremental changes in variable costs. Therefore, EPA's findings are not indicative of a relationship between *changes* in variable costs and generating output of coal-fired EGUs.

  Because the operation of the U.S. electricity system is largely governed by the principle of "economic dispatch" under which EGUs with the lowest variable costs are dispatched to generate electricity first, regression analyses that rely solely on current variable costs and historical output (as EPA's analysis does) are likely to almost always show a correlation between variable costs and generating output. However, such an observation carries little predictive power. In other words, it tells us little about whether output from highly utilized coal-fired EGUs, which tend to be located at the lower cost end of EGU dispatch curves, would be reduced due to an incremental increase in variable costs. Under economic dispatch, a coal plant's output is a function of its variable costs, system demand, and the amount of electricity that other lower cost EGUs in its supply zone can provide. As shown in Figures 4 and 5 below, if the total amount of electricity generated by the coal plant's lower cost competitors (after adding any incremental CCS-related costs) is less than the total electricity demand of the region,[212] then the coal plant's output will be largely unaffected by the higher variable costs.

[212] Depending on the amount of interzonal transmission capacity available, a limited amount of electricity may be imported form another region if lower cost EGUs are available in that region.

Figure 4: MISO Indiana Supply Curve and Variable Costs of EGUs[213]

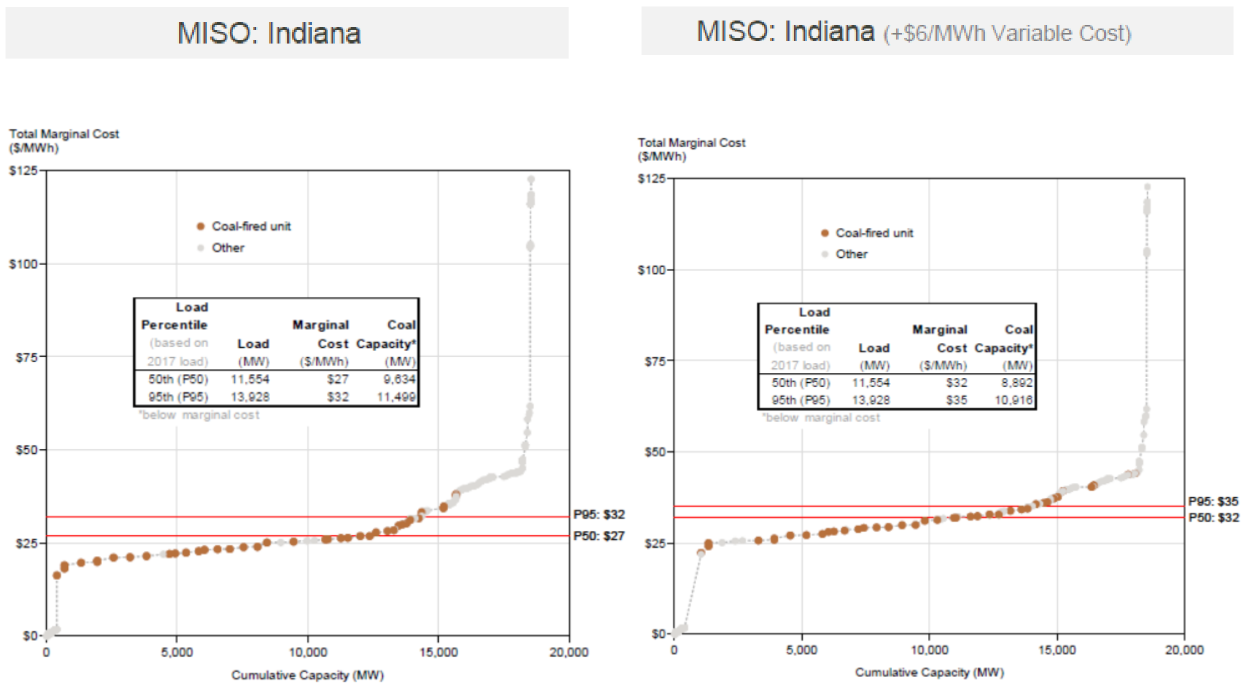


Figure 4 shows the regional electricity supply curve in the Indiana transmission area within the Midcontinent Independent System Operator (MISO) region before and after applying a $6/MWh increase to the marginal costs of all coal-fired EGUs—equivalent to EPA's assessment of the variable cost increase due to partial CCS.[214] As shown, well over 90% of the area's in-the-money coal-fired capacity continue to remain so after the addition of a $6/MWh increment to their variable costs.

[213] Analysis based on source data from ABB Velocity Suite. The analysis calculates the marginal costs at equilibrium points (where supply and demand are equal) for the 50th and 95th percentile hourly electricity demand levels in the MISO Indiana transmission area. Demand is based on reported 2017 actual hourly demand. Coal-fired EGUs with lower total marginal costs than that at the equilibrium points are considered to be "in-the-money", meaning they make operating profits during each hour they are run to generate electricity; while those with higher total marginal costs than at the equilibrium points are classified as "out-of-the-money", meaning they would lose money if they were run to generate electricity. The analysis then adds $6/MWh to the marginal costs of all coal-fired EGUs and recalculates the equilibrium points, associated marginal costs, and in-the-money and out-of-the-money coal-fired EGUs for the area. Finally, the analysis compares total capacities of coal-fired EGUs in the area, with and without the additional $6/MWh variable cost, that are in-the-money and out-of-the-money to illustrate the effects of increased variable costs.

[214] *See* NSPS Economic Impact Analysis, Table 3-7 at 3-22 (showing $5/MWh increase in variable operations & maintenance costs and $1/MWh increase in fuel cost going from SCPC to SCPC with partial CCS).

Figure 5: MISO Minnesota-North Dakota Supply Curve and Variable Costs of EGUs[215]

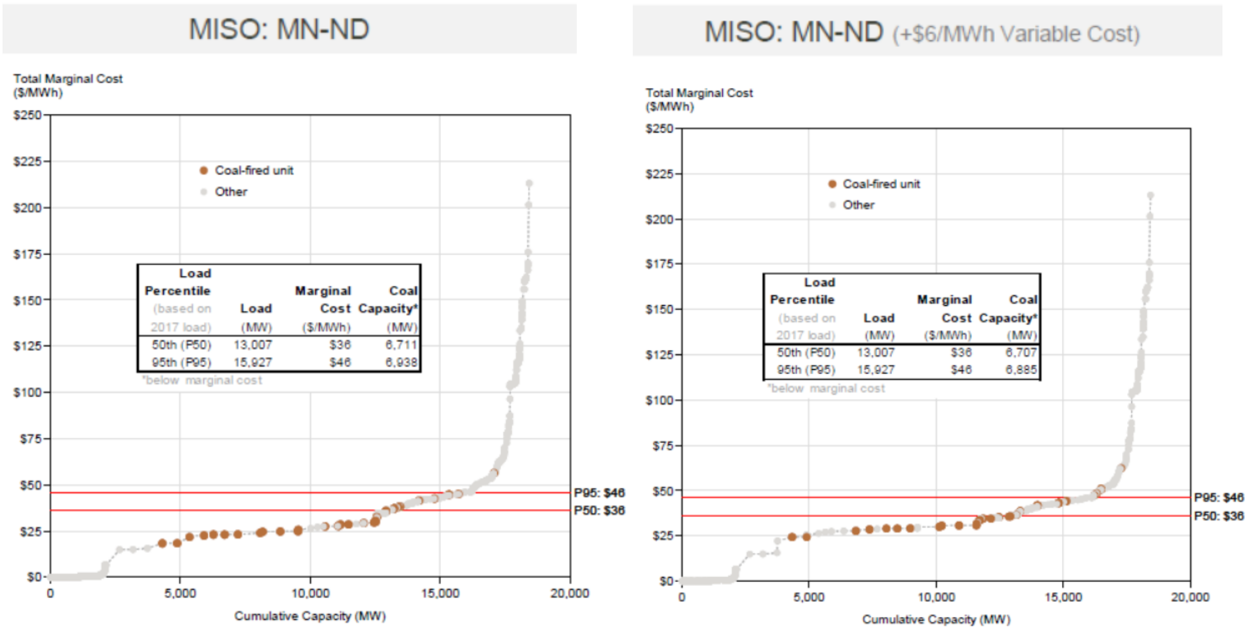


Figure 5 shows the regional electricity supply curve in the Minnesota-North Dakota transmission area in MISO before and after applying a $6/MWh increase to the marginal costs of all coal-fired EGUs. As shown, nearly 100% of the area's in-the-money coal-fired capacity continue to remain so after the addition of a $6/MWh increment to their variable costs. In other words, for both the Indiana and Minnesota-North Dakota transmission areas in MISO, the increase in variable costs due to partial CCS is not expected to materially affect coal plant utilization or capacity factor.

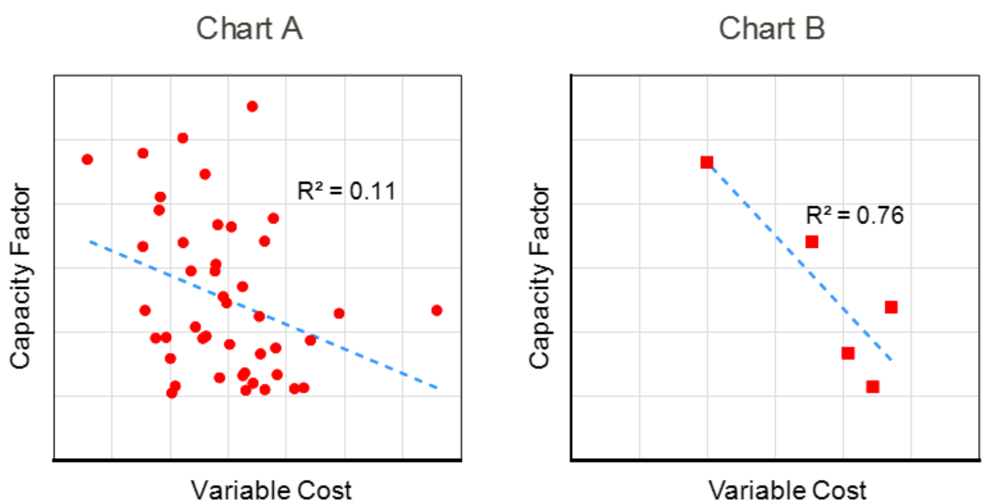
- *Binned and averaged sample data points can inflate R-squared values.* EPA's regression analysis is entirely based on binned and averaged sample data points, which can mask variances and produce results that falsely show strong correlation between variables. For instance, EPA's analysis shows relatively high R-squared values[216]—from 0.9 in January to almost 1 in December.[217] However, the sample data points used in each of the regression analyses represent averages of multiple subsets or bins of high capacity factor coal-fired EGUs. They do not reflect actual capacity factor and variable cost

[215] Analysis based on source data from ABB Velocity Suite. The analysis calculates the marginal costs at equilibrium points (where supply and demand are equal) for the 50th and 95th percentile hourly electricity demand levels in the MISO Minnesota-North Dakota transmission area. Demand is based on reported 2017 actual hourly demand. Coal-fired EGUs with lower total marginal costs than that at the equilibrium points are in-the-money while those with higher total marginal costs than at the equilibrium points are out-of-the-money. The analysis then adds $6/MWh to the marginal costs of all coal-fired EGUs and recalculates the equilibrium points, associated marginal costs, and in-the-money and out-of-the-money coal-fired EGUs for the area. Finally, the analysis compares total capacities of coal-fired EGUs in the area, with and without the additional $6/MWh variable cost, that are in-the-money and out-of-the-money to illustrate the effects of increased variable costs.
[216] R-squared values indicate how closely two variables follow a linear relationship. A value of 1 indicates a very close relationship while a value of 0 means that there is no relationship between them.
[217] *See* Memo on Variable Operating Cost Impacts, *supra* note 209, at Ex. 3 to 14.

combinations of any of the individual coal-fired EGUs. It is doubtful that the implied strong relationship between capacity factors and variable costs will still hold if raw data were used. In fact, when EPA does use actual capacity factors and variable costs of individual EGUs, albeit for all EGUs and not just high capacity factor ones, the resulting R-squared values are far lower—between 0.19 and 0.35.[218]

To illustrate how binning and averaging can artificially and significantly inflate R-squared values, consider the charts in Figure 6. Chart A is a scatter plot of about 40 randomly selected existing coal-fired power plants according to their variable costs and capacity factors in 2017. Running a simple regression analysis with these two variables suggests a relatively weak correlation of 0.11. However, grouping the same raw data for the 40 EGUs into five separate bins and plotting the average variable costs and capacity factors of each bin as a sample data point produces a much tighter apparent relationship with an R-squared value of 0.76 (Chart B). In other words, binning creates the impression of a strong relationship even when the underlying data shows no such relationship. EPA has thus not provided evidence of a relationship between capacity factors and variable costs, undercutting the notion that increased variable costs would be likely to result in reduced capacity factors such that plants could not recover those costs.

Figure 6: Illustrative Effect of Binning and Averaging on R^2 Values



v. EPA's Focus on Absolute Costs as Compared to Relative Costs Is an Arbitrary Basis to Conclude the Costs of CCS Are Unreasonable

In the 2015 Final Rule, in response to industry comments recommending EPA consider the cost metric of capital costs separately in addition to the LCOE metric, EPA analyzed the incremental capital costs of partial CCS and found they were reasonable because "they are comparable to those in prior regulations and to industry experience, and because the fossil steam electric power industry has been shown to be able to successfully absorb capital costs of this

[218] *See id.* at Ex. 1 and 2.

magnitude in the past."[219] EPA found partial CCS would require a reasonable increase in incremental capital costs of 21-22 percent.[220]

EPA now reconsiders this analysis—without changing its underlying estimate of capital costs—and draws a different conclusion. First, EPA states that because coal-fired power plants today are subject to more environmental controls than previously, the baseline costs of constructing a new coal-fired power plant are higher than at the time of past rulemakings EPA used to compare costs. So, at a same percentage increase in capital costs, the absolute capital costs are higher.[221] Second, EPA states that the prior NSPS rulemakings EPA used as a comparison concerned multiple pollutants and thus multiple requirements and control technologies, making it more difficult to use as a comparison.[222] Finally, EPA finds that even though the industry was able to absorb a 20 percent increase in capital costs in the past this does "not necessarily mean the industry could do so today."[223]

EPA's proposed reversal of its evaluation of capital costs in the 2015 Final Rule is arbitrary in part because EPA never explains *what* level of capital cost increase (on an absolute or relative basis) it considers to be acceptable for a given reduction in CO_2 emissions—much less justify such a threshold or explain why partial CCS exceeds it. And as discussed above, the Proposal's concern for avoiding any BSER that would materially affect the cost-competitiveness of coal-fired EGUs implies that EPA would not consider *any* increase in capital costs to be acceptable—a plainly unreasonable result. Also as noted above, EPA's new assertion that changes in the utility sector have caused more coal-fired EGUs to operate at variable load at lower capacity and lowered dispatch order could make it more difficult to recoup costs dismisses that it is unlikely that a new coal-fired power plant would be built outside of a regulated market where these concerns are irrelevant.

In any event, EPA's cursory discussion of on absolute and relative cost metrics fails to mention—and is divorced from—the relevant statutory question, which is whether partial CCS entails "exorbitant" costs that exceed the limits courts have articulated for a section 111 BSER. Courts that have considered the issue have clearly stated that in order for costs to be prohibitive to implementation of a chosen standard, the costs would have to be "exorbitant."[224] They have upheld costs that were "substantial" and would cost utilities "tens of billions of dollars," but would not jeopardize the industry's survival. *Sierra Club*, 657 F.2d at 314; *Portland Cement Ass'n*, 486 F.2d at 387-88 (upholding standard where agency found costs could be "be passed on without substantially affecting competition with . . . substitutes" even while observing "that individual mills may be closed in the years ahead, but . . . that these plants were obsolete both from a cost and pollution point of view"); *Portland Cement Ass'n.*, 513 F.2d at 508 (Court suggesting standards will be upheld unless "the costs of meeting standards would be greater than the industry could bear and survive").

[219] 2015 Final Rule, 80 Fed. Reg. at 64,559; *see also* Proposal, 83 Fed. Reg. at 65,440.
[220] 2015 Final Rule, 80 Fed. Reg. at 64,560.
[221] Proposal, 83 Fed. Reg. at 65,440.
[222] *Id.*
[223] *Id.*
[224] *Lignite Energy Council*, 198 F.3d at 933.

EPA does not show that the new standards would impose costs that the industry could not survive. When an agency decides to reverse course on a policy, it must "provide reasoned explanation," "display awareness that it *is* changing position," "show that there are good reasons for the new policy" and "*believe*[] it to be better."[225] When there are "serious reliance interests that must be taken into account," or when "the new policy rests upon factual findings that contradict those which underlay [the] prior policy," agencies must go further and "provide a more detailed justification than what would suffice for a new policy created on a blank slate."[226] The agency must also provide a "reasoned explanation . . . for disregarding facts and circumstances that underlay or were engendered by the prior policy."[227] Here, EPA has failed to provide a reasoned explanation for disregarding its previous finding. Rather than providing any analytical data showing that the costs of CCS would be exorbitant, EPA makes vague statements with no support.

The capital cost associated with the 2015 Final Rule is eminently reasonable in light of the small number of units that are expected to be subject to it,[228] and the comparatively large capital expenditures and revenue associated with the power sector. According to the most recent data available from the Energy Information Administration, U.S. power companies earned annual revenue of over $390 billion in 2017—an increase of approximately one percent over revenues earned in 2016.[229] The capital expenditures made by power companies year after year are similarly vast: investor-owned utilities alone are expected to make $109 billion in capital expenditures in 2019 alone, and actual and projected expenditures since 2015 have consistently exceeded $100 billion.[230] In 2016 and 2017, generation-related expenditures represented one of the largest components of these overall capital outlays (29-35% of the total).[231]

By contrast, NETL's baseline study estimates the capital cost of a CO_2 capture system for a model 644 MW subcritical EGU to be about $224 million and estimates capital costs of about $123 million for the other pollution control systems at the plant.[232] The CCS-related capital costs represent just 0.2% of total expected capital expenditures for investor-owned utilities in 2019 alone, and 0.06% of total revenues in 2017. Even in the unlikely event that multiple such CCS-equipped coal plants were constructed each year over multiple years, the impact to overall industry capital expenditures would be small—far smaller, in fact, than the ordinary annual fluctuations in capital expenditures seen in this industry. [233] EPA's correct expectation that relatively few coal-fired EGUs will be expected under the Proposal is an important reason why the industry is, if anything, *better* prepared to absorb the capital costs associated with partial CCS than prior standards that applied to a large number of new units. EPA has frequently

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[225] *Fox TV Stations, Inc.*, 556 U.S. at 515.
[226] *Id.*
[227] *Id.* at 515–16.
[228] Proposal, 83 Fed. Reg. at 65,427.
[229] ENERGY INFO. ADMIN, ELECTRIC POWER ANNUAL 2017 at tbl.1.1 (2018), https://www.eia.gov/electricity/annual/pdf/epa.pdf.
[230] Steve Kiesner, Presentation on Key Electric Industry Trends, at 5 (Apr. 19-20, 2018), https://www.energy.gov/sites/prod/files/2018/04/f51/fupwg_spring_2018_14-kiesner.pdf.
[231] *Id.* at 6.
[232] NAT. ENERGY TECH. LAB., COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS: VOLUME 1A: BITUMINOUS COAL (PC) AND NATURAL GAS TO ELECTRICITY 111 (2015) [hereinafter NETL Cost and Performance Volume 1A] (see lines 5B.1 and 5B.2).
[233] Kiesner, *supra* note 230, at 5.

considered such comparisons to overall industry capital expenditures and revenues when evaluating costs under section 111.[234]

Lastly, studies and experience have shown that the coal industry has readily adjusted to EPA regulations, and that environmental regulations have not played a major role in contributing to coal plant retirements.[235] EPA's preoccupation with the capital costs associated with the current BSER ignores the far more important role of market forces in determining decisions regarding whether to construct new coal-fired EGUs.

In any case, EPA's job is not to ensure the competitiveness of coal against other energy sources, but to promulgate achievable standards that achieve the greatest practicable degree of emission reduction with costs no greater than the industry can bear. EPA has not shown that the absolute increase in cost is one that the industry could not absorb as it has done in the past.

vi. EPA's Decision to Ignore Factors that Would Offset the Cost of CCS Is Arbitrary and Unlawful.

EPA's cost considerations have repeatedly failed to consider factors that would offset the costs of CCS to individual developers. The agency arbitrarily ignores the sizeable revenues that can be generated by selling captured CO_2 for enhanced oil recovery; the financial support provided by the expanded 45Q tax credits; and the substantial decline in capital costs likely to occur as CCS technology advances. This one-sided, incomplete cost analysis is fatal to this proposal.

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[234] *See* Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,617–18 (proposed Sept. 18, 2015) ("We also completed two additional analyses to further inform our determination of whether the cost of control is reasonable, similar to compliance cost analyses we have completed for other NSPS. First, we compared the capitals costs that would be incurred to comply with the proposed standards to the industry's estimated new annual capital expenditures . . . . We then determined whether the capital costs appear reasonable in comparison to the industry's current level of capital spending. Second, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us to evaluate the annualized costs as a percentage of the revenues being generated by the industry.").

[235] *See, e.g.*, Sean O'Leary, *New Energy Regulations Won't Bring Back WV Coal*, WEST VIRGINIA CENTER ON BUDGET AND POLICY (Aug. 22, 2018), https://wvpolicy.org/new-energy-regulations-wont-bring-back-wv-coal-2/ ("[t]hinning seams leading to lower productivity, competition from more productive western coal basins and the rise of natural gas" played a more important role in coal's decline than clean air regulations); Adam B. Jaffe, Steven R. Peterson, Paul R. Portney & Robert N. Stavins, *Environmental Regulation and the Competitiveness of U.S. Manufacturing: What Does the Evidence Tell Us?*, 33 J. of Econ. Literature 132 (1995), https://www.ucl.ac.uk/cserge/Jeffe%20et%20al%201995.pdf (study finding: "Overall, there is relatively little evidence to support the hypothesis that environmental regulations have had a large adverse effect on competitiveness."); TREVOR HOUSER, JASON BORDOFF & PETER MARSTERS, CAN COAL MAKE A COMEBACK (2017), https://energypolicy.columbia.edu/sites/default/files/Center_on_Global_Energy_Policy_Can_Coal_Make_Comeback_April_2017.pdf (analyzing the impact of environmental regulations on coal production between 2011 and 2016 and finding they are responsible only for 3.5 percent of the 33 percent total decline in coal production over that time).

1. Enhanced Oil Recovery Generates Sizable Offsetting Revenues

One offsetting factor against the costs of CCS application is the availability of CO_2-EOR revenues. Carbon dioxide enhanced oil recovery (CO_2-EOR) is a technique used to increase the amount of oil that can be recovered from an oil reservoir. The process generally entails injecting large volumes of CO_2 into an oil reservoir to help mobilize residual oil unrecovered by initial mechanisms. The CO_2 used "may come from anthropogenic or natural sources . . . [as t]he source of the CO_2 does not impact the effectiveness of the EOR operation."[236] "Of the various EOR processes, CO_2-EOR is the most widely used process with the highest potential for additional recovery."[237] In fact, CO_2-EOR produces over 300,000 barrels of oil per day, more than 5 percent of total U.S. oil production.[238]

Although CO_2 supply prices generally are not public information, they can be gleaned from oil prices because CO_2 supply prices for EOR tend to rise and fall with the price of oil.[239] Some have said that, as a general rule, a ton of CO_2 sells for about "35% of the price of a barrel of West Texas Intermediate oil."[240] Other estimates put the price at closer to 45% of the price of a barrel of oil.[241] These estimates comport with various NETL analyses that, when oil prices hovered around $95 at the beginning of the decade, typically assumed a CO_2 purchase cost of $40 per metric ton of CO_2.[242]

Past and projected oil prices suggest that CO_2-EOR revenues will continue to provide substantial value well into the future. The average price of a barrel of West Texas Intermediate (WTI) oil over the past 10 years is around $73, with a current price of $53.[243] Further, EIA forecasts based on business-as-usual trends project WTI crude oil prices to rise from $85.41 per

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[236] 2015 Final Rule, 80 Fed. Reg. at 64,579.

[237] U.S. GEOLOGIC SURVEY & MAHENDRA K. VERMA, FUNDAMENTALS OF CARBON DIOXIDE-ENHANCED OIL RECOVERY (CO_2-EOR)—A SUPPORTING DOCUMENT OF THE ASSESSMENT METHODOLOGY FOR HYDROCARBON RECOVERY USING CO_2-EOR ASSOCIATED WITH CARBON SEQUESTRATION 16 (2015), https://pubs.usgs.gov/of/2015/1071/pdf/ofr2015-1071.pdf.

[238] U.S. DEPARTMENT OF ENERGY, FOSSIL ENERGY RESEARCH BENEFITS: ENHANCED OIL RECOVERY at unnumbered p. 2 (last updated June 2012), https://www.energy.gov/sites/prod/files/eor_factcard.pdf.

[239] INT'L ENERGY AGENCY, STORING CO_2 THROUGH ENHANCED OIL RECOVERY: COMBINING EOR WITH CO_2 STORAGE (EOR+) FOR PROFIT 18 (2015), https://www.iea.org/publications/insights/insightpublications/Storing_CO2_through_Enhanced_Oil_Recovery.pdf.

[240] Marie B. Durrant, *Preparing for the Flood: CO_2 Enhanced Oil Recovery*, 59 RMMLF-INST 11-1, at 11-22 (2013); *see also* Jessica Holdman, *Companies Kick Off Carbon Capture Project in North Dakota*, BISMARCK TRIBUNE (Oct. 5, 2017) (quoting Anthony Armpriester, NRG's director of engineering and construction, as saying that "[w]hen oil prices are higher, about $100 per barrel, companies can afford to pay about $35 per ton [of carbon]").

[241] *See* INT'L ENERGY AGENCY, *supra* note 239 at 18 (citing a 2010 study that noted CO_2 contract prices at $30 per ton at oil prices of $70 per barrel); *see also* GLOBAL CCS INSTITUTE, GLOBAL TECHNOLOGY ROADMAP FOR CCS IN INDUSTRY: SECTORAL ASSESSMENT CO_2 ENHANCED OIL RECOVERY 23 (2011) ("In today's market, with oil prices in excess of $100 per barrel, delivered CO_2 costs where some CO_2-EOR projects remain economically viable could be as high as $40 to $45 per metric ton.").

[242] *See* WALLACE, KUUSKRAA, DIPIETRO & NAT. ENERGY TECH. LAB., AN IN-DEPTH LOOK AT NEXT GENERATION CO2-EOR TECHNOLOGY (2013); *see also* NAT. ENERGY TECH. LAB., IMPROVING DOMESTIC ENERGY SECURITY AND LOWERING CO2 EMISSIONS WITH "NEXT GENERATION" CO_2-ENHANCED OIL RECOVERY (CO_2-EOR) (2011); Brad Crabtree, The Critical Role of CCS and EOR in Managing US Carbon Emissions Presentation 17 (Apr. 11, 2016).

[243] *See WTI Crude Oil Prices – 10 Year Daily Chart*, MACROTRENDS, https://www.macrotrends.net/2516/wti-crude-oil-prices-10-year-daily-chart (last updated Mar. 12, 2019).

barrel in 2025 to $129.11 per barrel in 2040.[244] The above-described relationship between oil prices and CO_2 supply prices thus suggests an average price for CO_2 over the past 10 years of $25-$32 per ton. It also suggests that while the current price of CO_2 is likely around $18-$23 per ton, future CO_2 prices can reasonably be expected to climb from around $29-38 per ton in 2025 to around $45-58 per ton in 2040, so long as the oft-noted relationship between CO_2 prices and oil prices continues to hold.

CO_2 revenues within these ranges would be a significant offset against the capital costs of CCS. According to an NETL analysis, the current cost of capture for power sector projects is between $60 and $70 per metric ton of CO_2.[245] CO_2-EOR supply revenues are therefore well-positioned to offset a significant portion of these costs for the foreseeable future.

2. Section 45Q Tax Credits Provide Significant Offsetting Value

A second offsetting factor against the costs of CCS application is the availability of 45Q tax credits. The Section 45Q tax credit—extended and expanded by the Bipartisan Budget Act of 2018—now provides substantial financial support to power plants and other facilities using carbon capture and storage. For dedicated geological storage of CO_2, the value of the credit increases incrementally from $28 to $50 per metric ton of carbon by 2026. For carbon stored through EOR, the credit increases from $17 to $35 per metric ton by 2026. These transferrable credits last for 12 years starting on the date the equipment is first placed into service, and there is no cap on the number of credits a project can generate. A carbon capture project may be eligible for the credit provided that it commences construction before January 1, 2024.

Like EOR revenues, the 45Q credits would offset a significant portion of the cost of CCS. For example, a power plant beginning construction today that goes into service in 2024 would be able to receive a tax credit of $45 per metric ton of captured carbon deposited in geological storage of captured carbon. That figure would increase to $50 per ton by 2026, and then rise with an inflation multiple in the twelve subsequent years of eligibility.[246] This means that, given NETL estimates for the per ton cost of CO_2 capture, *see supra*, the 45Q credit offers tax credits that represent roughly 75% of the per ton cost of capture for CCS projects using geological storage.

[244] *See* ENERGY INFO. ADMIN, ANNUAL ENERGY OUTLOOK 2016 at CP-3, tbl. CP2 (2016) (comparing oil price projections in 2015 dollars per barrel); *see also id.* at iii (defining the reference case as "a business-as-usual trend estimate, given known technology and technological and demographic trends"). In its High Oil Price case, EIA projects WTI crude oil prices as high as $180.49 per barrel in 2025, and $222.27 per barrel in 2040. *See id.* at CP-3, Table CP2. In its Low Oil Price case, on the other hand, EIA projects WTI prices of $36.57 per barrel in 2025 and $67 per barrel in 2040. *Id.*
[245] *See* DEP'T OF ENERGY, CARBON CAPTURE, UTILIZATION, AND STORAGE: CLIMATE CHANGE, ECONOMIC COMPETITIVENESS AND ENERGY SECURITY 5 (2016) [hereinafter DOE CARBON CAPTURE, UTILIZATION, AND STORAGE] (citing NETL COST AND PERFORMANCE VOLUME 1A, *supra* note 232, at 17); *see also* Rubin, Davison & Herzog, *The Cost of CO_2 Capture and Storage*, INT'L J. GREENHOUSE GAS CONTROL 379, 382, tbl.2 (2015) (estimating the cost of post-combustion capture at SCPC power plants to be between $36-53).
[246] *See* Simon Bennett & Tristan Stanley, *Commentary: U.S. Budget Bill May Help Carbon Capture Get Back on Track*, INT'L ENERGY AGENCY (Mar. 12, 2018), https://www.iea.org/newsroom/news/2018/march/commentary-us-budget-bill-may-help-carbon-capture-get-back-on-track.html.

Indeed, expert reports and analyses have underscored that these credits will provide a significant economic value for new CCS projects. A report put together by former Energy Secretary Ernest Moniz estimated that a CCS-equipped "500 MW supercritical coal plant burning bituminous coal, and operating at an 80 percent capacity factor" could, at a 90 percent capture rate, "accrue tax credit revenues of about $125 million each of 12 years for saline formation storage," approximately $1.5 billion total.[247]

To be sure, CCS projects necessitate significant front-end capital costs. For this reason, some have suggested that because 45Q credits are generated over time and are not available upfront, 45Q will be ineffective in spurring investment in and development of CCS. [248] These criticisms are unavailing. The 45Q tax credit is similar to the renewables production tax credit (PTC),[249] which has successfully propelled the growth of wind energy notwithstanding the initial capital costs for projects and the need for financing.[250] The PTC provides an inflation-adjusted tax credit to qualified facilities for every kWh of renewable generation produced, thereby incentivizing CO_2 emissions reductions.[251] Several studies and reports have confirmed that these incentives have played a significant role in the growth of wind,[252] underscoring that per-unit tax credits can effectively spur technological development, even when there are high front-end capital costs. Similarly, 45Q offers tax credits to incentivize CO_2 emissions reductions. These credits—like the PTC—incentivize CO_2 capture on a per-unit basis as opposed to an upfront sum. The PTC-driven success of wind energy, however, demonstrates the effectiveness of a per-unit incentive in a comparable capital cost-heavy context.[253] Furthermore, taking on debt is the

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247 ENERGY FUTURES INITIATIVE, ADVANCING LARGE SCALE CARBON MANAGEMENT: EXPANSION OF THE 45Q TAX CREDIT 16 (2018).

248 *See* Holly Krutka, *Renewed Momentum for Carbon Capture in the US*, WORLD COAL ASS'N (Apr. 19, 2018), https://www.worldcoal.org/renewed-momentum-carbon-capture-us (noting that CCS projects will require financing for capital costs since the 45Q credits are not available upfront, but expressing optimism because "[m]ost experts believe that there will be CCUS projects as a result of 45Q reform").

249 26 U.S.C. § 45; *see Incentives for CO_2 Avoided: Comparison of Renewables Production Tax Credit and Proposed 45Q Legislation*, CLEAN AIR TASK FORCE (Dec. 19, 2017), http://www.catf.us/wp-content/uploads/2017/12/CATF_FactSheet_Cost_of_CO2_Avoided.pdf [hereinafter *Incentives Avoided*] (noting that the programs are comparable because both use per-unit tax credits to incentivize CO_2 emission reductions).

250 *See* NAT. RENEWABLE ENERGY LAB., WIND ENERGY FINANCE IN THE UNITED STATES: CURRENT PRACTICE AND OPPORTUNITIES 1 (2017), https://www.nrel.gov/docs/fy17osti/68227.pdf (highlighting the sustained investment and continued growth in wind capacity in recent years while noting the "capital-intensive" nature of a wind farm); *see also* MOLLY F. SHERLOCK, CONG. RESEARCH SERV., THE RENEWABLE ELECTRICITY PRODUCTION TAX CREDIT: IN BRIEF, at unnumbered p.2 (2018) ("The PTC has been important to the growth and development of renewable electricity resources, particularly wind.").

251 *See Incentives Avoided*, *supra* note 249, at 1–2.

252 *See, e.g.*, SHERLOCK, *supra* note 250, at 8–9 (noting Congress's recognition in 1999 that the PTC aided development of renewable power, and explaining that "[r]ecent extensions of the PTC reflect a belief that the tax nicentives contribute to the development of renewable energy infrastructure"); Gireesh Shrimali, Melissa Lynes & Joe Indvik, *Wind Energy Deployment in the U.S.: An Empirical Analysis of the Role of Federal and State Policies*, 43 RENEWABLE & SUSTAINABLE ENERGY REVS. 796 (2015) ("Overall, the results [of our regression analysis] . . . provide[] strong evidence that the production tax credit has been highly significant in driving wind energy deployment in the U.S.").

253 Some have questioned whether the expansion of 45Q can effectively spur CCS development since power companies might occasionally have insufficient tax liability to use all of the credits they generate. *See* Krutka, *supra* note 248 ("Not all power companies pay enough in taxes to directly use the tax credits that would be generated."); SHERLOCK, *supra* note 250, at 10 (asserting that tax credits are not the most efficient means of incentivizing investment in and development of renewables since "[s]tand-alone projects often have limited tax liability"). Despite

norm for this industry and not unduly disruptive to its business plans, provided that utilities can eventually recover the up-front costs. Because the power sector has historically paid off capital investments over long time periods, 45Q credits will offset costs when they are typically recouped by utilities. Thus, 45Q credits are relevant to EPA's consideration of costs in the BSER analysis, and EPA's failure to account for them is arbitrary and unlawful.

3. CO_2-EOR and 45Q Together Provide Even More Substantial Offsetting Value, and One Recent Analysis Indicates that CCS-Equipped Coal Plants Could Bid Negative Into the Wholesale Market

The combination of EOR revenue and 45Q tax credits would provide even more substantial mitigation of the costs of CCS application. By 2026, CCS projects storing via EOR will receive a credit of $35 per ton under the 45Q program. As discussed above in the section on EOR, CO_2 sales likely yield around $20 per ton today, and can reasonably be expected to increase to around $29-38 per ton by 2025. Thus, the combined value of the credit and CO_2 sales revenues may reasonably range from $55-73 per ton of captured carbon in the near-term. This represents a considerable mitigation of NETL's control cost estimate of $60-70 per ton of captured CO_2.

Recent findings from a University of Texas analysis provide strong confirmation. That analysis indicated that a CCS-equipped coal plant utilizing the $35 per ton credit for the full 12 years could be competitive with NGCC units provided that it could sell its CO_2 for EOR for around $15 per ton over the lifetime of the plant.[254] The analysis goes on to say that, given the favorable economics, such coal plants could potentially "bid *negative*" into the wholesale market during their 12 years of tax credit eligibility, mirroring wind's ability to bid negative prices into the market on the strength of the Production Tax Credit.[255]

4. CCS Capital Costs Are Likely to Decrease Considerably Due to R&D and Continued Learning

Declining capital costs stemming from innovation and learning is yet another offsetting factor to weigh against CCS costs. Capital costs for new coal-fired power plants implementing CCS are likely to decline with continued research and development. Indeed, the U.S. Department of Energy, NETL, and the Electric Power Research Institute have all predicted substantial cost reductions from technological advances spurred by R&D.[256]

this potential inefficiency, however, project developers with insufficient tax liability can nonetheless reap significant benefits from the 45Q credits by monetizing them under tax-equity financing arrangements. *Id.*

[254] Joshua D. Rhodes, Commentary, *New Federal Budget Puts Price on Carbon: Expanded Carbon Credit Could Spur New Coal Power Investment*, UNIVERSITY OF TEXAS ENERGY INSTITUTE, at unnumbered p. 3 (Mar. 9, 2018).

[255] *Id.* at unnumbered p. 2; *see also* Joshua D. Rhodes, *How Clean Coal Could Make a Tidy Profit,* FORBES (Apr. 19, 2018), https://www.forbes.com/sites/joshuarhodes/2018/04/19/how-clean-coal-could-make-a-tidy-profit/#3d6cb0375654.

[256] *See generally* Kristin Gerdes et al., *Current and Future Power Generation Technologies: Pathways to Reducing the Cost of Carbon Capture for Coal-fueled Power Plants*, 63 ENERGY PROCEDIA 7541 (2014); Edward S. Rubin et al., The Cost of CO_2 Capture and Storage, 40 INT. J. GREENHOUSE GAS CONTROL 378 (2015).

Moreover, successive iterations of emergent technologies also generate declining capital costs. Technology tends to move along a "learning curve" as development and implementation build on "the experience of early adopters, plus added knowledge gained as a technology diffuses more widely into the marketplace."[257]

This "well-known phenomenon" has important implications for CCS.[258] Specifically, capital and operating costs for CCS projects will decrease as developers and operators continue to learn from the mistakes and inefficiencies of previous projects.[259] For instance, Petra Nova's developer points out that if they were to repeat the project the cost would be about 20 percent lower.[260] Similarly, academic, government, and industry experts at a Resources for the Future workshop estimated that second-generation technologies could lead to "25-30 percent lower capital costs and 20-30 percent lower operating costs if current R&D goals are met."[261] In the 2014 Proposed Rule EPA noted that SaskPower, owner of the Boundary Dam Power Station which has been implementing full-scale CCS technology since 2014, at the time was considering additional CCS projects, which, though not pursued, were expected to cost 30% less than its Boundary Dam #3 project.[262]

More recently, SaskPower along with the International CCS Knowledge Centre, has conducted a feasibility study of implementing CCS technology at the Shand Power Station. This study, published in November 2018, reveals significant reductions in the costs associated with CCS moving forward. The study found that the capital costs of the Shand facility would be 67% lower than Boundary Dam on a dollar per ton of CO_2 basis,[263] in part due to lessons learned through implementation of CCS at Boundary Dam.

5. EPA Repeatedly and Arbitrarily Failed to Consider Widely Available Factors That Mitigate CCS Costs

a. EPA's Failure to Consider Readily Available Cost Mitigation Options Is Arbitrary

[257] Edward S. Rubin et al., *The Outlook for Improved Carbon Capture Technology*, 38 PROGRESS IN ENERGY & COMBUSTION SCI. 1, 9 (2012).
[258] Rubin et al., *supra* note 256, at 380.
[259] *Id.*; *see also* GLOBAL CCS INSTITUTE, GLOBAL COSTS OF CARBON CAPTURE AND STORAGE 2 (2017) ("[F]irst attempts [at CCS] involved considerable contingencies and hence dramatic cost reductions are expected for second and subsequent attempts.").
[260] *See* Heather Richards, *Carbon Dioxide from Coal Plants Has an Interested Buyer From Oil and Gas, if the Costs Come Down*, CASPER STAR TRIBUNE (Oct. 23, 2017).
[261] RESOURCES FOR THE FUTURE, THE FUTURE OF CARBON CAPTURE, UTILIZATION, AND STORAGE (CCUS): STATUS, ISSUES, NEEDS: EVENT SUMMARY 2 (2017).
[262] *See* 2015 Final Rule, 80 Fed. Reg. at 64,565 (citing Mike Monea, Presentation at the 12th International Conference on Greenhouse Gas Technologies: Boundary Dam – The Future is Here (Oct. 2014)).
[263] INTERNATIONAL CCS KNOWLEDGE CENTRE, THE SHAND CCS FEASIBILITY STUDY PUBLIC REPORT 77 (2018), https://ccsknowledge.com/pub/documents/publications/Shand%20CCS%20Feasibility%20Study%20Public%20_Full%20Report_NOV2018.pdf.

When determining the BSER for new sources under 111(b), the Clean Air Act requires that EPA "take[] into account the cost of achieving" the required emissions reductions. [264] The D.C. Circuit has stated that EPA's standard may not impose costs that are "exorbitant,"[265] "unreasonable,"[266] or "greater than the industry could bear."[267] But "the costs of applying best practicable control technology [should] be considered by the owner of a large new source of pollution as a normal and proper expense of doing business."[268]

Though EPA has broad discretion in choosing the *means* of cost consideration,[269] the agency is not permitted to inflate the cost of achieving the required emissions reductions by arbitrarily failing to consider certain countervailing factors. An agency rule is arbitrary and capricious if the agency "entirely failed to consider an important aspect of the problem,"[270] and "[m]erely to look at only one side of the scales . . . flunks this basic requirement."[271] The agency "cannot put a thumb on the scale by undervaluing the benefits and overvaluing the costs of more stringent standards."[272]

Here, EPA has improperly and unlawfully "put [its] thumb on the scale" by arbitrarily and unreasonably excluding consideration, again and again, of readily available and well-established options that will significantly reduce the cost of a CCS project. Following a pattern of this proposal, the agency considers only the worst case scenario, without providing any record evidence that such suboptimal conditions would actually exist, and without considering widely available options to reduce the costs of a project.

b. EPA's Analysis Arbitrarily Excludes CO2-EOR from its Cost Considerations

As discussed above, CO_2-EOR has the potential to significantly offset CO_2 capture costs. EPA's proposal pays lip-service to these potential revenues, and then summarily dismisses them in two short sentences:

> While sale of the captured CO_2 improves the overall economics of a new coal-fired EGUs, [sic] the EPA recognizes that there are places where opportunities to sell captured CO_2 for utilization may not be presently available. Therefore, consistent with approach [sic] adopted in the 2015 Rule, the EPA is assuming no revenues from the sale of captured CO_2 (80 FR 64572).[273]

EPA's decision to ignore EOR revenues is flawed and arbitrary for at least two reasons. First, its reasoning directly conflicts with its previous conclusions regarding the geographic availability of CO_2-EOR. In the 2015 Final Rule, EPA developed a robust record detailing CO_2-

[264] 42 U.S.C. 7411 (a)(1).
[265] *Lignite Energy Council*, 198 F.3d at 933.
[266] *Sierra Club v. Costle*, 657 F.2d at 384.
[267] *Portland Cement Ass'n*, 513 F.2d at 508.
[268] H.R. Rep. No. 95-294, at 184.
[269] *Husqvarna AB* v. EPA, 254 F.3d 195, 199–201 (D.C. Cir. 2001).
[270] *State Farm*, 463 U.S. at 43.
[271] *Cal. v. Bureau of Land Mgmt.*, 277 F. Supp. 3d 1106, 1122 (N.D. Cal. 2017).
[272] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1198 (9th Cir. 2008).
[273] Proposal, 83 Fed. Reg. at 65,440.

EOR's substantial and growing infrastructure. The agency pointed out that CO_2-EOR operations were ongoing in 12 states at the time, that "13 states have operating CO_2 pipelines," that "18 states [were] within 100 kilometers of an active EOR location," and that "an additional 17 states have geology that may be amenable to EOR operations."[274] EPA thus explicitly rejected the contention by "[s]ome commenters . . . that the existing CO_2 pipeline capacity is not adequate and that CO_2 pipelines are not available in" most of the country:

> The EPA does not agree. The CO_2 pipeline network in the United States has almost doubled in the past ten years in order to meet growing demands for CO_2 for EOR. CO_2 transport companies have recently proposed initiatives to expand the CO_2 pipeline network. Several hundred miles of dedicated CO_2 pipeline are under construction, planned, or proposed, including projects in Colorado, Louisiana, Montana, New Mexico, Texas, and Wyoming.[275]

EPA cannot now claim that it cannot consider these substantial revenues because "there are places" where the CO_2 would not be able to be sold for utilization.[276] Indeed, new sources under the standard would have the ability to factor proximity to EOR and pipelines into their siting decisions,[277] and EPA fails to articulate any rationale for its implied conclusion that new sources would deliberately choose to cut themselves off from such a significant source of revenue. As discussed in section II.F.i, EPA is not required to ensure sources may be sited at any location in the country, so assuming sources would factor proximity to EOR into this analysis is reasonable.

Second, and contrary to EPA's assertion, this approach is inconsistent with that taken in the 2015 rulemaking. That rulemaking "assum[ed] no revenues from sale of captured CO_2" in order to show that its cost estimates were reasonable even when EOR opportunities were not available.[278] The agency's assumption did not reflect a finding or belief that EOR was too geographically limited to be included in its cost considerations. Rather, it embodied a conservative approach taken to show that EPA's estimates were reasonable in all scenarios. Here, EPA is doing precisely the opposite. Despite the wide geographic availability of EOR sales opportunities,[279] EPA places inordinate weight on a few hypothetical "places" where these opportunities "may not be available."[280] EPA's cost estimates thus reflect only this limited and unfounded scenario, and the agency's reliance on this unsubstantiated assumption only serves to further illustrate this proposal's characteristic disregard for complete and balanced analysis.[281] Additionally, the agency's exclusion of EOR revenues on this basis arbitrarily ignores the fact

[274] Memorandum from EPA on Geographic Availability, at 1 (July 31, 2015) [hereinafter 2015 Memo on Geographic Availability].
[275] 2015 Final Rule, 80 Fed. Reg. at 64,581–82.
[276] Proposal, 83 Fed. Reg. at 65,440.
[277] *See* 2015 Final Rule, 80 Fed. Reg. at 64,572 ("For new sources, pipeline distance and costs can be factored into siting.").
[278] *Id.* at 64,572.
[279] *See* 2015 Memo on Geographic Availability, *supra* note 274 and accompanying text; *see also* 2015 Final Rule, *supra* note 275 and accompanying text.
[280] Proposal, 83 Fed. Reg. at 65,440.
[281] As discussed in Section II.F.i on EPA's treatment of geographic concerns in the context of the adequately demonstrated nature of partial CCS, EPA improperly places arbitrary and unsubstantiated constraints on selection of the BSER by assuming the source must be able to be sited at any possible location across the country.

that new coal plants have the ability and incentive to take EOR proximity into account when making siting decisions.

c. EPA's Analysis Arbitrarily Excludes the 45Q Tax Credit from Its Cost Considerations

The proposed rule offers scant explanation for why its CCS cost consideration fails to account for the 45Q credit. The agency merely says that its cost calculations:

> "[D]o not account for any specific economic incentives (*e.g.*, the federal tax credits for carbon capture), which are available only for new facilities that commence construction before January 1, 2024 . . .[,] which, in turn, is before the end of the 8-year period in which the EPA is required to review and, if necessary, revise the standard of performance that is the subject of this rulemaking . . . ."[282]

This brief discussion provides no rational justification and explanation for EPA's failure to consider, as part of the agency's evaluation of CCS' costs, the significant value readily provided by 45Q—a program specifically directed at just this type of project.

EPA appears to be suggesting that because section 111(b) requires that EPA review and revise the NSPS *at least* every eight years, if EPA sets a standard that must be reviewed by 2026 at the latest there will be a two-year period (2024-2026) during which potential new plants will not be eligible for the 45Q credit. Thus, if EPA is to set a BSER that might not be reviewed for eight years, it cannot consider these substantial offsets, which are available for only six years.

But this flawed reasoning fails to account for the considerable cost reductions likely to be at play in those later years. As discussed above, learning and maturation of CCS technology are expected to cut capital costs by as much as 30% for projects *currently* in development. Further cost reductions are to be expected for *Nth-of-a kind* projects.[283] This progression along the learning curve will likely be accelerated by the rule,[284] and could potentially be on par with the tax credit for those years.[285]

The agency's failure to account for declining capital costs provides stark illustration of its arbitrary decision-making. EPA attempts to ignore six years' worth of sizeable tax credits by focusing on the last two years of the statutory eight-year review period, during which new facilities would no longer be eligible for the credit if it is not extended by Congress. Yet, despite this focus on the future, EPA ignores a key element of it—namely, that the capital cost of CCS is

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[282] *Id.*
[283] *See* Rubin et al., *supra* note 256, at 379.
[284] *See, e.g.*, LARRY PARKER & JAMES E. MCCARTHY, CONG. RESEARCH SERV., CLIMATE CHANGE: POTENTIAL REGULATION OF STATIONARY GREENHOUSE GAS SOURCES UNDER THE CLEAN AIR ACT 18 (2009) (describing how sulfur dioxide regulation accelerated "scrubbers" from fringe to industry standard).
[285] *See* DOE CARBON CAPTURE, UTILIZATION, AND STORAGE, *supra* note 245, at 5 ("DOE's goal is to reduce the cost of capture to $30-$40 per metric ton, which could be achieved through successful [research, development, demonstration, and deployment].").

likely to have decreased significantly by that time.[286] EPA cannot have it both ways, considering only certain elements of the future but not others.

Additionally, the history of the Production Tax Credit (PTC) and Investment Tax Credit (ITC) suggests that Congress is likely to renew the credits offered under 45Q. Both the PTC and ITC have been renewed and expanded multiple times since their respective enactments.[287] Failure to acknowledge and account for this possibility with respect to 45Q is unreasonable. Moreover, even if Congress does not extend the tax credit, EPA has the discretion to revisit the NSPS and its BSER determination in light of that development and newer cost figures before the eight-year review period has run. This is precisely what EPA would do with respect to any other uncertainty regarding potential future increases or decreases in the cost of a standard, *e.g.*, the cost of materials or the availability of equipment. Uncertainty regarding extension of 45Q is no different from uncertainty over these other cost elements—except insofar as Congress determines the availability of cost offsets under 45Q and utilities may lobby to extend the program. Section 111 requires that EPA set a standard that controls new source pollution to the "maximum practicable degree" based on the information the agency has.[288] The agency cannot dilute this responsibility by completely ignoring 45Q's sizeable offsets based on arbitrarily foreclosing the likelihood of—and the agency's ability to respond in the face of—legislative developments that may or may not occur in 2024.[289]

6. EPA's Analysis Repeatedly Irrationally Emphasizes Unrealistic Scenarios

EPA's disregard of readily available sources of offsets to the cost of CCS is yet another example of the agency irrationally clinging to unrealistic cost scenarios. EPA posits a CCS project that forgoes EOR, does not pursue 45Q credits, and utilizes an exclusive storage site without seeking to share costs with other facilities. But that does not reflect the record of how developers plan and finance their projects. For example, Petra Nova factored EOR into its siting decision and "partnered with Hilcorp Energy to construct an 80-mile pipeline to route [its] captured carbon dioxide to increase production at the West Ranch oil field—helping make an environmental solution an economical one, too."[290]

vii. EPA Arbitrarily Relies on BACT Determinations Which Provide No Support that CCS is Not of Reasonable Cost

EPA attempts to support its unlawful proposal by relying on several PSD BACT determinations. This reliance, however, ignores a critical distinction between BACT and BSER

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[286] *See* Rubin et al., *supra* note 256, at 379.
[287] *See generally* MOLLY SHERLOCK, CONG. RESEARCH SERV., THE ENERGY CREDIT: AN INVESTMENT TAX CREDIT FOR RENEWABLE ENERGY (Nov. 2, 2018); *see also* Sherlock, SHERLOCK, *supra* note 250, at 3–5.
[288] *Essex Chem. Corp.*, 486 F.2d at 437 (citing Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970, 116 Cong. Rec. 42,384, 42,385 (1970)); *see also Sierra Club*, 657 F.2d at 326 (a standard of performance must "reduc[e] emissions as much as practicable.").
[289] *See Chlorine Chemistry Council*, 206 F.3d at 1290-91 ("EPA cannot reject the 'best available' evidence simply because of the possibility of contradiction in the future by evidence unavailable at the time of the action—a possibility that will *always* be present.").
[290] *See Petra Nova: Carbon Capture and the Future of Coal Power*, NRG, https://www.nrg.com/case-studies/petra-nova.html (last visited Mar. 15, 2019). EPA offers no explanation for assuming that developers would do otherwise.

determinations—namely, that the former are made for specific proposed facilities that are being newly built or modified, while the latter are made for facilities yet to be proposed or built, and are intended to shape the decisions about proposing and building new facilities. Moreover, EPA reasonably concluded in its 2015 Final Rule that these BACT determinations did not support the argument that partial CCS was not the BSER for coal-fired EGUs. Now taking the opposite view, EPA's arbitrary failure to reckon with these issues renders this proposal unlawful.

1. The BACT Determinations Relied Upon by EPA Have Little, if any, Relevance to the Determination That Partial CCS is the BSER Because PSD Permitting Occurs in a Regulatory Context Very Different from NSPS Rulemakings.

BACT determinations occur in a regulatory context very different from NSPS rulemakings. With respect to partial CCS, the critical distinction between BACT and BSER is that, in the BACT context, whether a given control technology is economically and technically feasible for a permit-seeking facility is often influenced by of owner/operator decisions (including siting and business-purpose choices) made *prior to* the BACT determination. The permitting authority therefore often takes various limitations and constraints into account, including the facility's footprint, age, and proximity to geologic sequestration, oil fields, and CO_2 pipelines.[291] This is a reflection of the fact that BACT determinations are particularized inquiries focused on the unique characteristics of an individual facility. "[T]he BACT definition requires permit issuers to 'proceed[] on a case-by-case basis, taking a careful detailed look, attentive to the technology or methods appropriate for the particular facility, [] to seek the result *tailor-made for that facility* and that pollutant.'"[292] "The BACT determination results in the selection of an emission limitation representing application of control technology or methods appropriate for the particular facility." [293]

In the NSPS context, on the other hand, the BSER establishes a regulatory framework for facilities that have yet to be proposed. These new facilities, therefore, do not "face the same types of constraints as modified or reconstructed sources in a BACT determination, since a new source has more leeway in choosing where to site."[294] New sources can consider the contours of the NSPS and then factor land acquisition needs and proximity to pipelines and geological storage into their siting decisions.[295] BSER analyses therefore require EPA to take a national view and make broad determinations about what is feasible for potential new plants. Because of this fundamental difference between the two contexts, "individual BACT decisions [are not]

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[291] *See, e.g.*, MASS. DEP'T OF ENVT'L PROTECT., FINAL PREVENTION OF SIGNIFICANT DETERIORATION PERMIT FACT SHEET: SALEM HARBOR REDEVELOPMENT PROJECT 13 (2012) (concluding that CCS was not BACT for a proposed facility because of the lack of CO_2 pipeline infrastructure proximate to the predetermined site); *see also* EPA, EPA-457/B-11-001, PSD AND TITLE V PERMITTING GUIDANCE FOR GREENHOUSE GASES 36 (2011) ("EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on control that are typically used . . . . Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations.").

[292] *In re La Paloma Energy Center, LLC*, PSD Appeal No. 13-10, slip op. at 9 (EAB Mar. 14, 2014) (emphasis added) (quoting *In re N. Mich. Univ.*, PSD Appeal No. 08-02, slip op. at 12 (EAB Feb. 18, 2009)) (alterations in original).

[293] *Id.* at 9 (citing *In re Prairie State Generating Co.*, 13 E.A.D. 1, 12 (EAB 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007)).

[294] 2015 Final Rule, 80 Fed. Reg. at 64,631–32 n.551.

[295] *Id.* at 64,572 ("For new sources, pipeline distance and costs can be factored into siting.").

determinative of whether a particular technology is adequately demonstrated for purposes of section 111(b)."[296]

This distinction undercuts the agency's assertion that these BACT determinations are relevant to, much less supportive of, its BSER analysis. Yet EPA unlawfully fails to even acknowledge it, and certainly does not supply the "reasoned explanation" legally required for disregarding a distinction it previously relied upon in its 2015 BSER determination. [297]

2. EPA's 2015 Conclusion that Prior BACT Determinations Were Consistent with Defining Partial CCS as the BSER Remains Valid, and the Agency's Reasons Apply with Equal Force Today.

EPA attempts to justify its rejection of partial CCS in the BSER context by pointing to a handful of years-old PSD permitting decisions for proposed new and modifying facilities that determined CCS was not the BACT. EPA suggests that a BSER based on partial CCS would be inconsistent with these prior BACT determinations, despite the fact that the agency rejected precisely this argument in the 2015 Final Rule.[298] The reasons supporting EPA's robust rejection of this argument in 2015 apply with equal force today, and it is therefore unlawful for EPA to now reverse course on this point without explaining why its previous conclusions are no longer valid.

a. EPA Previously Found the BACT Determinations in Question to be of Limited and Waning Relevance Because Nearly All of Them Were Made Several Years Ago.

The BACT determinations that EPA now references were made several years ago, and EPA itself acknowledged the rapidly changing context and growing base of knowledge regarding GHG control technology. The agency cautioned:

> PSD permitting requirements first applied to GHGs in January 2011 and more information about GHG control technology has been gained in this four-and-a-half-year period. Thus, we would expect BACT decisions to evolve as well, such that a GHG BACT review for a coal-fired EGU in 2015 may look very different from a review that was done in 2011.[299]

This reasoning, initially advanced in 2015, applies with even greater force four years later. Ten of the 13-14 BACT analyses on which EPA now relies were conducted between 2011 and 2012, and two others were conducted in 2013 and 2014 respectively.[300] These analyses do

[296] RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-19 (Response 6.3-31).
[297] *Fox TV Stations*, 556 U.S. at 515.
[298] 2015 Final Rule, 80 Fed. Reg. at 64,631–32 (rebutting argument made by "commenters who stated that a BSER for EGUs that is based on partial CCS would be inconsistent with BACT determinations in previous GHG PSD permits"); *see also* RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-142 to -143 (Response 6.3-237) (noting several reasons why its partial CCS BSER determination was not inconsistent with BACT determinations in previous GHG PSD permits).
[299] 2015 Final Rule, 80 Fed. Reg. at 64,632.
[300] *See* Memorandum from EPA on Review of BACT Determinations for GHG Emissions (Dec. 2018).

not reflect the latest state of CCS technology, which has continued to mature over the past several years, as discussed in detail elsewhere in our comments.[301] Accordingly, EPA previously recognized that contemporary GHG BACT decisions might "look very different" from these older determinations, and eschewed reliance on them. [302] Now, despite industry's evolved understanding and development of CCS technology since finalization of the 2015 Final Rule, EPA proposes to reverse course and rely on these historic determinations—now four years more out-of-date—to support its conclusion that partial CCS is no longer the BSER.[303] The agency's failure to square this reliance with its earlier reasoning is arbitrary and unlawful.

Only one of the determinations relied upon by EPA is less than five years old—the Irvington Generating Station BACT. That 2017 determination, however, bears little relevance to the BSER determination at hand, for at least two reasons. First, Irvington proposed to add "up to ten natural gas-fired reciprocating internal combustion engines (RICE)."[304] Such units are fundamentally different from coal-fired power plants and, for reasons expounded below, BACT determinations for such units are not probative to a BSER for coal-fired generation. Second, and more importantly, Irvington's BACT was constrained by the pre-existing, decades-old facility's remoteness to CO_2 storage and pipelines.[305] Construction of a transport pipeline was therefore included in the $379 million capital cost asserted by Irvington, and the permitting authority concluded that this capital cost made CCS economically infeasible. But a report by the Center on Globalization, Governance & Competitiveness indicates that the pipeline construction costs may have comprised a substantial portion of the total capital cost.[306] This serves to underscore the fundamental distinction, discussed above, between BACT and BSER determinations. Whereas Irvington's control options were constrained by siting decisions made prior to its PSD application, sources in the BSER context can consider attributes such as proximity to pipelines into their siting decisions.

b. EPA Previously Found that BACT Determinations for Full CCS Bear Little-to-No Relevance to a Partial CCS BSER.

In 2015, EPA rejected the relevance of several of the BACT determinations upon which the agency now attempts to rely because they evaluated full, not partial, CCS.[307] The cost

[301] *See supra*, section II.A.
[302] 2015 Final Rule, 80 Fed. Reg. at 64,632.
[303] Conversely, the agency has presented no evidence that, since issuing the 2015 NSPS, permitting authorities have struggled to meet the "BACT floor" established by the 2015 NSPS without requiring partial CCS. If EPA's and permitting authorities' views of CCS were at odds, and the authorities were previously exercising their discretion to reject CCS, one might expect authorities to have had greater difficulty issuing permits since an emissions level reflecting CCS became the BACT floor in 2015.
[304] ARIZONA DEP'T OF ENVT'L QUALITY, TECHNICAL SUPPORT DOCUMENT FOR IRVINGTON GENERATING STATION AIR QUALITY PERMIT # 1052, at 1 (Aug. 8, 2018).
[305] *Id.* at 18 ("There is no on-site or nearby storage option for the quantity of CO_2 emitted from the proposed RICE units . . . [and] [c]urrently no pipeline exists to transport the CO2 from the site to a sequestration location.").
[306] Kristen Dubay & Gary Gereffi, *Carbon Capture and Storage: A Post-Combustion Capture Technology*, *in* MANUFACTURING CLIMATE SOLUTIONS 17 tbl. 5 (last updated May 12, 2009) (estimating the cost of a 200-mile pipeline to be roughly $300 million).
[307] *See* EPA, RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-199 (Response 6.3-291) (distinguishing the Iowa and Michigan BACT determinations for Mid-American Energy George Neal North, Mid-

differences between full and partial CCS are, of course, substantial, as are sizing and land availability issues. [308]. Thus EPA correctly rejected the notion that BACT determinations evaluating only full CCS call into question its determination that partial CCS is the BSER for coal-fired units. EPA now partly relies on such BACT determinations to support its rejection of partial CCS as the BSER, yet unlawfully fails to provide a reasoned explanation for this change.[309]

c. EPA Previously Concluded that It Was Not Bound by State BACT Determinations.

EPA noted that many of the BACT determinations were state agency decisions, and rejected the notion that these decisions served as administrative precedent for the purposes of setting the NSPS.[310] Now, EPA suggests that partial CCS cannot be the BSER because such a determination would be inconsistent with the agency's silence regarding state-level permitting decisions that did not consider CCS to be BACT.[311] But in 2015 EPA made clear that state agency permits not proposing or considering CCS as BACT were not a reflection of EPA's view on CCS, because "EPA is not necessarily required to comment negatively on the draft permit, or to otherwise request or require that the state agency amend the BACT to include CCS."[312] Thus, "[i]f the EPA does not adversely comment on a certain draft permit or BACT determination, it does not necessarily imply EPA endorsement of the proposed permit or determination."[313] EPA previously concluded that a BSER of partial CCS was consistent with its silence on these state permitting decisions, and it was appropriate for EPA later to conclude, having conducted a BSER analysis, that the level of emissions resulting from partial CCS is the BACT floor. Indeed, it is entirely appropriate for a BACT floor reflecting the emission level resulting from the BSER to influence permitting decisions, as Congress expressly included this floor in the definition of "BACT"[314] despite the fact that new and modified sources are already subject to the NSPS under section 111.[315] The agency's failure to explain its rationale for now reaching a contrary conclusion is arbitrary and unlawful.

d. EPA Previously Concluded that BACT Determinations for Natural Gas Plants Bore Little-to-No Relevance to a BSER Determination for Coal Plants.

EPA rejected the relevance of the same BACT determinations on which the agency now relies because many of these analyses were for gas-fired EGUs. Units of this type present

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American Energy George Neal South, and Wolverine Clean Energy Venture in part because "these agencies were evaluating full CCS, not partial CCS").

[308] *See, e.g.*, 2015 Final Rule, 80 Fed. Reg. at 64,596 (rejecting full CCS as BSER).

[309] *See* Proposal, 83 Fed. Reg. at 65,441.

[310] 2015 Final Rule, 80 Fed. Reg. at 64,632.

[311] *See* Proposal, 83 Fed. Reg. at 65,441.

[312] *Id*.

[313] *Id.*; *see also* RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-19 (Response 6.3-31) ("Nor is EPA's silence with regard to individual state permits at all precedential (or probative at all) for EPA's actions in this rulemaking.").

[314] 42 U.S.C. § 7479(3).

[315] *Id.* § 7411(a)(2).

economic and technical considerations distinct from that of the coal-fired EGUs subject to the NSPS. Thus, EPA concluded that "[a]lthough, in the course of a BACT review, some permitting authorities may have determined that CCS is not technologically feasible or economically achievable for a gas-fired EGU, because of the case-by-case nature of the BACT analysis it does not automatically follow that the same conclusion is appropriate for a solid fuel-fired EGU."[316].

EPA now suggests otherwise, making no attempt to explain why it has reversed its view on this point.This is arbitrary and capricious by definition, and therefore unlawful.

EPA concluded in 2015 that the small number of BACT determinations rejecting CCS were consistent with its finding that CCS was the BSER because those prior BACT determinations were materially unrelated, particularly because they addressed specific proposed new or modified facilities constrained by siting and business-purpose choices made prior to the permit application. EPA has provided no new information, new developments, or any other reasonable justification to set aside this conclusion, much less the "more detailed justification" required by law.[317] Such arbitrary and capricious decision-making is unlawful, and EPA should withdraw the proposed rule as a result.

F. EPA's Determination that Partial CCS Is Not Adequately Demonstrated on the Basis of Geographic Availability Is Arbitrary.

EPA declares that a primary reason for its proposed reversal of its determination that partial CCS constitutes BSER is the "limited geographic availability" of CCS.[318] Like its analysis of cost, EPA's claim that alleged geographic unavailability justifies eliminating partial CCS as BSER is arbitrary and unsupported. The Proposal calls into question whether geologic storage in sedimentary saline formations is "adequately demonstrated," even though the information EPA cites to in the Proposal regarding the range and capacity of suitable storage locations in the United States either confirms or strengthens the conclusions in the 2015 Final Rule in all material respects. EPA offers practically no new information or analysis to support its changed position regarding geographic availability of CCS. In fact, EPA concedes that the updates to the agency's analysis of the availability of geologic sequestration sites "do not significantly change the EPA's understanding of which areas are amenable" to geologic sequestration.[319] At most, EPA contends that it overestimated the availability of geologic sequestration sites by only up to 4 percent,[320] and as explained below, even that contention is doubtful.

Lacking an argument that there has been any significant change in the agency's understanding of the availability of sequestration sites, EPA argues that is now believes that limited water availability in the Western U.S. "suggests that many sequestration sites *might not* have sufficient water resources" to operate carbon capture equipment.[321] But that's about as far as EPA's analysis goes: the Western U.S. has less water than other parts of the country and

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[316] 2015 Final Rule, 80 Fed. Reg. at 64,632.
[317] *FCC v. Fox*, 556 U.S. at 515.
[318] Proposal, 83 Fed. Reg. at 65,426.
[319] *Id.* at 65,441.
[320] *Id.*
[321] *Id.* at 65,444 (emphasis added).

carbon capture equipment needs water, so perhaps there is insufficient water to support partial CCS at locations in the Western U.S.[322] The Proposal provides no information whatsoever to indicate that water resources in any part of the country are so constrained as to prevent the construction of new coal-fired EGUs with partial CCS. Moreover, the Proposal's analysis of water requirements associated with partial CCS systems assumes a dry cooling baseline found at just a handful of EGUs in the United States,[323] overlooking potential technologies and techniques that could be used to mitigate water demand at CCS-equipped units, and ignoring the fact that dry cooling has *lower* absolute water requirements than EPA considered in the 2015 Final Rule. EPA's unsupported conjecture regarding the possibility that water resources may be insufficient to support CCS at some locations does not suffice as an adequate reasoned basis to reverse its well-supported 2015 determination that partial CCS constitutes BSER for coal-fired EGUs.

Regarding the limited number of locations where utilizing partial CCS may be infeasible, EPA explained in its 2015 rulemaking that CAA section 111 does not require that a BSER be capable of being implemented at literally any location, and the case law makes clear that section 111 standards should not reflect "least common denominator" approaches driven by consideration of "worst case" scenarios for the configuration and operation of new sources.[324] Indeed, like sources themselves, many pollution control systems require resources that may be scarce or costly in some areas (such as access to water, or transport infrastructure). That CCS may be more difficult or more costly to implement in certain locations or with certain plant configurations is not a reason to discard it as the BSER, particularly when the alternative put forward in the Proposal would achieve no meaningful reduction in greenhouse gases.

To the extent that EPA now believes that the selected BSER must be available everywhere, EPA fails to offer a reasoned basis for such changed legal interpretation, nor is one available: the statutory language, caselaw, and legislative history all support EPA's 2015 interpretation.

In any event, EPA's proposal says nothing to refute EPA's 2015 conclusion that no new source would be restricted from achieving the standard of performance due to the lack of access to sequestration capacity, because there are adequate alternative compliance options available.[325] First, EPA explained that the areas where geologic sequestration may be infeasible also tended to be areas where it was very unlikely that a coal-fired EGU would be built.[326] Second, EPA concluded that in the limited number of locations potentially lacking suitable carbon sequestration sites where a company might actually want to construct a new coal-fired EGU, other compliance options are available.[327] Specifically, EPA explained that a power company can transport CO_2 to a geologic sequestration site via CO_2 pipelines, or locate its units closer to a

[322] *See id.*
[323] *Id.* at 65,443.
[324] *See Portland Cement Ass'n v. EPA,* 665 F.3d 177, 190 (D.C. Cir. 2011) (upholding NSPS for cement kilns against industry challenge that EPA had failed to consider an "entirely conjectural species of kiln")*; Kennecott Greens Creek Mining Co. v. MSHA,* 476 F.3d 946, 957 (D.C. Cir. 2007) ("The fact that "a few isolated operations within an industry" will not be able to comply with the standard does not undermine a showing that the standard is generally feasible.").
[325] 2015 Final Rule, 80 Fed. Reg. at 64,581.
[326] *Id.* at 64,576.
[327] *Id.* at 64,581-83.

geologic sequestration site and provide electric power to customers through transmission lines ("coal-by-wire").[328] EPA further explained that there are alternative means of complying with the final standards of performance that do not necessitate use of partial CCS, such as co-firing with natural gas.[329] EPA concluded that these alternative compliance options "moot[] the issue of the geographic availability of geologic sequestration."[330] EPA arbitrarily fails to explain in its new Proposal why it now believes that these alternative compliance options are insufficient to address concerns regarding the potential unavailability of partial CCS at a limited number of geographic locations.

i. EPA Places Arbitrary Constraints on the BSER by Assuming the Source Must Be Able to be Sited at Any Location in the Country.

EPA's proposed conclusion that the limited number of areas where partial CCS may not be available renders partial CCS not "adequately demonstrated" appears to be based on EPA's belief that a BSER must be capable of being implemented at literally any location in the country.[331] But as EPA explained in its 2015 rulemaking, nothing in CAA section 111 requires EPA to ensure that any new source at any geographic location could comply with the standards of performance for new sources.[332] EPA arbitrarily fails to offer any basis for abandoning this well-reasoned legal interpretation.

Contrary to EPA's suggestion, nothing in section 111 requires EPA to select BSER based solely on technologies or other emission reduction approaches that are available anywhere that someone may wish to construct a new major source. Rather, section 111(a)(1) broadly instructs that a standard of performance must be based on 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) … has been adequately demonstrated." The D.C. Circuit explained in *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981), that this language does not require EPA to determine BSER "simply at the plant level," but instead requires EPA to "examine the effects of technology *on the grand scale* in order to decide which level of control is best."[333] Here, on the "grand scale," partial CCS is a feasible emission reduction approach on both a national and regional level. *See infra*.

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[328] *Id.*
[329] *Id.* at 64,513.
[330] *Id.* at 64,541.
[331] *See* Proposal, 83 Fed. Reg. at 65,441 (suggesting that "all new steam-generating EGUs" must be able to implement partial CCS, and that "depends on the geographic scope of suitable [geologic sequestration] sites.").
[332] 79 Fed. Reg. 1430, 1466 (Jan. 8, 2014) ("Under CAA section 111, an emissions standard may meet the requirements of a 'standard of performance' even if it cannot be met by every new source in the source category that would have constructed in the absence of that standard."); *id.* at 1481 ("EPA is authorized to promulgate standards of performance under CAA section 111 that may have the effect of precluding construction of sources in certain geographic locations."), *id.* at 1467 (concluding that it "should not be viewed as inconsistent with congressional intent for section 111" if an NSPS forecloses certain new sources in a location because "EPA promulgates section 111 emission limits based on a particular type of technology, and for economic or technical reasons, sources are able to utilize that technology in only certain parts of the country and not other parts.").
[333] *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981) (emphasis added). While *Costle* held that EPA could not disregard the fact that a given technology does not constitute the "best" system of emission reduction across a significant swath of the country, that is not the circumstance here, where EPA has documented widespread

Likewise, while the D.C. Circuit held in *National Lime Ass'n v. EPA* that EPA must consider the "range of relevant variables that may affect emissions in different plants" and ensure that section 111 standards are achievable "for the industry as a whole" this does not mean that every new facility regulated by the standard regardless of location or design must be able to utilize the technology selected as BSER.[334] Indeed, EPA has a history of setting standards under CAA section 111 and similar provisions that are not achievable by every potential new source regardless of location or design. For example, in setting the 1979 NSPS for electric utility generating units, EPA selected as BSER wet scrubbers that produced sludge that could not easily be disposed of in all geographic situations.[335] In *Portland Cement Ass'n v. EPA,* the D.C. Circuit rejected an industry challenge to an NSPS for cement kilns contending that the standard was not achievable by a particular type of cement kiln, holding that EPA was not required to ensure that its NSPS was achievable by an older kiln design that was unlikely to be built.[336] And in *International Harvester Co. v. Ruckelshaus*, the D.C. Circuit upheld EPA's Clean Air Act emission standard for light duty vehicles that precluded certain types of vehicles, holding that such exclusion is permissible "as long as feasible technology permits the demand for new passenger automobiles to be generally met."[337] Similarly, in *Kennecott Greens Creek Mining Co. v. MSHA*, the D.C. Circuit upheld a Federal Mine Safety and Health Administration technology standard on the basis that the selected control technology was "feasible" for the regulated industry even though "a few isolated operations within an industry will not be able to comply."[338]

Interpreting section 111 as not requiring the selected BSER to be available for every potential new source at every potential location is consistent with the legislative history of CAA section 111 and the Act as a whole. When enacting section 111 in 1970, the Senate explained: "Major new facilities such as electric generating plants … must be controlled to the maximum practicable degree *regardless of their location and industrial operations*."[339] The Senate further declared that "[t]he maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems while cleaning up existing sources."[340] In light of this unambiguous legislative intent to prevent future pollution problems by applying maximum available controls to new sources, Congress could not have intended for EPA to forgo requiring effective greenhouse gas controls for new sources in the most polluting sector based on the possibility that such controls may be unavailable in a small number of geographic locations.

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geographic availability of partial CCS, and no other available control technology significantly reduces a coal-fired EGU's greenhouse gas emissions.

[334] 627 F.2d 416, 431 (D.C. Cir. 1980).

[335] 44 Fed. Reg. 33,580, 33,594 (June 11, 1979).

[336] 665 F.3d 177, 190 (D.C. Cir. 2011). The Court also reasoned that should a new kiln of this older design be built, there were alternative methods of compliance available. *Id.* at 191.

[337] 478 F.2d 615, 640 (D.C. Cir. 1973) (explaining that "the driving preferences of hot rodders are not to outweigh the goal of a clean environment.").

[338] 476 F.3d 946, 957 (D.C. Cir. 2007) (quotation omitted).

[339] S. Rep. 91-1116 at 16 (1970) (emphasis added).

[340] 91 Cong. Senate Report 1196, CAA70 Leg. Hist. 19.

In fact, Congress expressly acknowledged that the 1970 Act's attainment provisions might entirely prevent new sources from being constructed in some parts of the country.[341] Here, by contrast, because section 111(b)(5) prohibits EPA from requiring a new source "to install and operate any particular technological system of continuous emission reduction," a new coal-fired EGU can be constructed even where partial CCS is unavailable, so long as it utilizes an alternative strategy to achieve compliance with the NSPS emission limitations. Given Congress' unambiguous intent for section 111 to eliminate air pollution problems created by new stationary sources, combined with flexibility built into section 111 for sources to comply with an NSPS using pollution reduction approaches other than the selected BSER, it would be unreasonable and arbitrary to read into section 111 a requirement that the BSER on which EPA bases a new source performance standard be available to any potential new source in any geographic location. Accordingly, even if it were true that setting the performance standard for new coal-fired EGU based on the use of partial CCS would result in a standard that might not be attainable by every potential new coal-fired EGU in any geographic location, such possibility would not disqualify partial CCS as BSER.

ii. EPA's Conclusion That Geologic Storage Availability is Not Adequately Demonstrated is Arbitrary and Capricious

In the 2015 Final Rule, EPA correctly concluded—on the basis of a voluminous technical record—that geologic storage of captured CO_2 has been adequately demonstrated in a range of geologic formations, including oil and gas reservoirs, saline formations, and unmineable coal seams; that geologic storage capacity is well-distributed across the United States; and that the widespread availability of storage makes the NSPS for new steam EGUs readily achievable, especially given that new EGUs have considerable flexibility with respect to siting as well as various alternative means of compliance with the NSPS (such as natural gas co-firing and use of IGCC technology).[342] The Proposal raises vague and unsubstantiated concerns that storage in sedimentary formations and unmineable coal seams has not been adequately demonstrated,[343] but presents no concrete information that would warrant any change to the well-supported conclusions EPA reached in the 2015 Final Rule. Indeed, the Proposal's analysis of geologic storage capacity confirms the agency's prior conclusions in all material respects. Because EPA has failed to offer a "good reason" for "disregarding the facts and circumstances that underlay its prior policy,"[344] it would be arbitrary and capricious for EPA to determine that partial CCS is no longer the BSER on the basis of geographic availability concerns.

1. The Record for the 2015 Final Rule Strongly Supports the Widespread Availability of Geologic Storage

In the preamble to the 2015 Final Rule, EPA came to the well-supported conclusion that geologic sequestration of CO_2 is "technically feasible and available throughout the United States."[345] EPA observed that large quantities of naturally occurring CO_2 have been sequestered in underground repositories for millions of years, and that the "mechanisms by which CO_2 is

[341] S. Rep. 91-1116 at 2 (1970).
[342] 2015 Final Rule, 80 Fed. Reg. at 64,575–83.
[343] Proposal, 83 Fed. Reg. at 65,441-42.
[344] *Fox TV Stations*, 556 U.S. at 515.
[345] 2015 Final Rule, 80 Fed. Reg. at 64,575.

trapped underground are well understood." [346] EPA noted that the geologic conditions needed for successful sequestration are present in deep saline formations, oil and gas formations, and unmineable coal seams; that deep saline storage capacity has been identified in 39 states; and that EOR operations were then being conducted in 12 states, with the potential for EOR to be carried out in at least 17 additional states.[347]

Because saline formations are so widespread and have such a large potential capacity to store CO_2, EPA provided a particularly detailed discussion of geologic sequestration potential in deep saline formations. EPA noted that both DOE and the U.S. Geological Survey (USGS) have carried out analyses of geologic sequestration capacity in these formations, and that DOE has concluded that saline formations alone have the capacity to store at least 2 trillion metric tons of CO_2. USGS reported an even greater mean storage capacity of 3 trillion metric tons of CO_2, taking account of both deep saline formations and oil and gas reservoirs.[348]

EPA also noted that DOE's seven Regional Carbon Sequestration Partnerships had initiated eight large-scale "development phase" projects as of 2015, following a long period of testing and validation of smaller projects.[349] Of these eight projects, five had already injected or completed injecting CO_2 into deep saline formations.[350] Three of those projects had injected more than one million metric tons each, with one injecting a total of eight million metric tons between 2009 and 2013.[351] EPA noted that DOE had applied a variety of rigorous monitoring techniques to these sites, and had detected no leakage of CO_2.[352]

EPA also addressed the adequately demonstrated potential for geologic sequestration in other sedimentary formations, including oil and gas reservoirs and unmineable coal seams. EPA described the over forty years of successful experience in the United States with sequestration of CO_2 through EOR, noting that approximately 60 million metric tons of CO_2 were sequestered in the United States through EOR in 2013 alone and that about 30 percent of this total represented captured CO_2 from anthropogenic sources.[353] EPA noted that several major EOR projects have been subject to intensive monitoring and verification programs over a period of years to ensure that the injected CO_2 is permanently sequestered, with no evidence of leakage detected.[354] With respect to unmineable coal seams, EPA noted that DOE's regional sequestration partnerships have "documented the location of approximately 56 to 114 billion metric tons of potential CO_2 storage resource in unmineable coal seams in 21 states." [355]

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346 *Id.* at 64,585-76.
347 *Id.* at 64,576.
348 *Id.* at 64,579.
349 *Id.*
350 *Id.*
351 *Id.*
352 *Id.*
353 *Id.* at 64,580.
354 *Id.*
355 Memorandum from EPA on Geographic Availability, at 9 (July 31, 2015) [hereinafter 2015 Memo on Geographic Availability] (citing NAT. ENERGY TECH. LAB. & DEP'T OF ENERGY, THE UNITED STATES 2012 CARBON UTILIZATION AND STORAGE ATLAS (4th ed. 2012)).

EPA's Response to Comments on the 2015 Final Rule pointed to additional evidence indicating that long-term, large-scale geologic sequestration in a variety of formations is more than adequately demonstrated. EPA noted that commercial-scale injection of excess CO_2 in saline formations has been demonstrated as part of the Boundary Dam project, as well as at the Sleipner, Snøhvit, and In Salah storage facilities.[356] EPA also noted that Sleipner, Snøhvit, and separate EOR sequestration projects "have demonstrated continuous operation for many years," and have been monitoring reservoir conditions for decades.[357] Moreover, underground injection of CO_2 is subject to stringent regulatory control under the Underground Injection Control programs for Class II (EOR),and Class VI injection wells.[358] As further confirmation of the technical feasibility and integrity of deep saline storage, EPA noted that it had issued six Underground Injection Control (UIC) Class VI permits for deep saline injection at two projects.[359] These permits were based on "demonstrations that CO_2 would be securely confined to prevent the movement of fluids into or between [underground sources of drinking water] or into any unauthorized zones."[360] One of these Class VI projects permitted sequestration of 22.5 million tons of CO_2 from a future carbon capture project at a steam generating EGU.[361]

Although EPA acknowledged in the 2015 Final Rule that "[p]roject- and site-specific factors do influence where CO_2 can be safely sequestered,"[362] it found that the "widespread potential for [geologic sequestration] in the United States" coupled with the flexibility available to new sources with respect to siting and compliance made it feasible for new steam EGUs to achieve the final standard.[363] EPA noted, among other things, that the owner of a new steam EGU can choose to locate the unit close to any number of viable sequestration sites and "wheel"

[356] RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-26 (Response 6.3-44), 6-51 (Response 6.3-82).
[357] *Id*. at 6-48; *see also id.* at 6-27 (Response 6.3-44) ("[I]nternational experience with large scale commercial GS projects has demonstrated through extensive monitoring programs that large volumes of CO_2 can be safely injected and securely sequestered for long periods of time at volumes and rates consistent with those expected under this rule.").
[358] *See generally* 2015 Final Rule, 80 Fed. Reg. at 64,586–90; *see also* RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 2-141 to -142 (SAB Work Group finding that "while the scientific and technical basis for carbon storage provisions is new and merging science, the agency is using the best available science and has conducted peer review at a level required by agency guidance" (quoting Memorandum from James R. Mihelcic, Chair, Science Advisory Board Work Group on EPA Planned Actions for SAB Consideration of the Underlying Science, on Revised Recommendations on the Adequacy of the Science Supporting the Standards for Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generation units (20160AQ-91) Listed in the Spring 2013 Regulatory Agenda (Jan. 24, 2014)). Commenters had falsely claimed that EPA's 2015 determinations regarding the efficacy of CO_2 injection and sequestration had not been presented to the SAB or undergone proper peer review.
[359] 2015 Final Rule, 80 Fed. Reg. at 64,585.
[360] RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-23 (Response 6.3-39).
[361] *Id.* at 6-27 (Response 6.3-44), 6-46 (Response 6.3-78).
[362] 2015 Final Rule, 80 Fed. Reg. at 64,581.
[363] *Id.*; *see also* RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-54 (Response 6.3-87) ("The EPA recognizes that the USGS review cited in the proposed rule is an initial assessment of storage capacity and additional site specific work would be needed to demonstrate that a specific site meets the requirements for safe and secure storage under the UIC Class VI rules. Given the large areal extent of potential storage areas, the EPA believes that based on the USGS assessment suitable storage areas can be identified in proximity to new power plants.").

its output to load centers through the existing transmission network.[364] Alternatively, EPA noted that a new steam EGU can choose to locate closer to load centers and rely on existing or new CO_2 pipelines to transport captured CO_2 to a geologic storage site.[365] In rare circumstances where neither of these options is feasible, EPA noted that owners of new steam EGUs can rely on alternative techniques that "do not necessitate use of partial CCS"—such as natural gas co-firing—to comply with the NSPS without regard to need for sequestration capacity.[366]

2. More Recent Information Confirms EPA's Conclusions in the 2015 Final Rule

Other information developed after the finalization of the current NSPS supports the conclusions EPA reached in the 2015 Final Rule. Following the finalization of the 2015 Final Rule, DOE released a fifth edition of its Carbon Storage Atlas that reflects the Department's most up-to-date assessment of geologic storage potential across a variety of sedimentary formations in the United States. This latest Carbon Storage Atlas confirms the extensive geologic storage estimates cited in the 2015 Final Rule, and finds that overall geologic storage potential in the United States is larger than previously estimated—ranging from a low-end estimate of 2.6 trillion metric tons (an approximately 9 percent increase over the previous low-end estimate) to as high as 22 trillion metric tons.[367] The 2015 Carbon Storage Atlas also supports the feasibility of large-scale storage in saline formations, noting that extensive experience with injection and storage of natural gas in saline formations is applicable to the storage of CO_2[368] and that "recent project results suggest that [saline formations] can be used as reliable, long-term storage sites."[369]

Since October 2015, DOE's Regional Carbon Sequestration Partnerships ("RCSP") have also continued to move forward with large-scale, long-term demonstration phase projects that are demonstrating the feasibility of geologic storage in a variety of conditions across the United States, including in saline formations. As of 2017, these projects include:[370]

Project	Type	CO_2 Source	Basin	Amount Stored (metric tons)

[364] *See* 2015 Final Rule, 80 Fed. Reg. at 6,4582–83 (discussing potential for "coal-by-wire"); 2015 Memo on Geographic Availability, *supra* note 274, at 11–18 (describing available transmission infrastructure in every major region of the continental United States, and opportunities to source coal-fired generation from neighboring states and regions).

[365] *See* 2015 Memo on Geographic Availability, *supra* note 274, at 10–12 (noting that there were almost 5,200 miles of CO_2 pipelines located in 13 states as of 2013, a 38 percent increase in pipeline mileage since 2004; and that large new pipelines were either recently completed or under construction, including Denbury's recently-completed 325-mile Green Pipeline and 232-mile Greencore Pipeline).

[366] 2015 Final Rule, 80 Fed. Reg. at 64,581 (citing *Portland Cement III*, 665 F.3d at 191). EPA also noted that in the few states that lack native geologic storage capacity, it is unlikely that new coal-fired EGUs will be built given "lack of available coal or state law prohibitions and restrictions against coal-fired power plants." *Id.* at 64,576, 64,583.

[367] NAT. ENERGY TECH. LAB. & DEP'T OF ENERGY, CARBON STORAGE ATLAS 3 (5th ed. 2015) [hereinafter 2015 CARBON STORAGE ATLAS].

[368] *Id.* at 26.

[369] *Id.* at 28.

[370] Traci Rodosta et al., *U.S. DOE Regional Carbon Sequestration Partnership Initiative: New Insights and Lessons Learned*, 114 ENERGY PROCEDIA 5580, 5583 (2017).

Illinois Basin Decatur Project	Saline	Ethanol Facility	Illinois Basin	999,215
Michigan Basin Project	EOR	Natural Gas Processing Facility	Michigan Basin	596,282
Bell Creek Field Project	EOR	Natural Gas Processing Facility	Powder River Basin	2,982,000
Citronelle Project	Saline	Coal-fired EGU	Interior Salt Basin	114,104
Cranfield	EOR/Saline	Jackson Dome	Interior Salt Basin	4,743,898
Farnsworth	EOR	Ethanol Facility, Fertilizer Plant	Anadarko Basin	490,720

In addition, DOE has launched a new initiative called CarbonSAFE that is aimed at establishing the feasibility of large-scale geologic storage in repositories with capacities of 50 million metric tons or greater. Thirteen CarbonSAFE projects are currently in the "pre-feasibility" stage, and three have advanced to full feasibility studies.[371] As of January 2018, over 16 million metric tons of CO_2 have been injected and safely stored through the RCSP and other projects sponsored by DOE.[372]

As these large-scale demonstration phase projects have progressed, DOE has distilled lessons learned into a series of five "best practices manuals" that were most recently updated in 2017. These five manuals are designed to provide "a holistic set of guidelines for conducting the many aspects of a geologic storage projects from inception to completion," and to establish "effective methods, reliable approaches, and consistent standards for conducting successful geologic storage projects in a variety of settings."[373] Likewise, the International Organization for Standardization (ISO) has developed a series of eight international standards covering every aspect of CCS, including a standard published in October 2017 for geologic storage in saline aquifers and other formations.[374] These ISO standards are a reflection of the well-demonstrated nature of geologic storage and the growing base of global experience and expertise with this technology.

[371] CarbonSAFE, NETL, https://www.netl.doe.gov/coal/carbon-storage/storage-infrastructure/carbonsafe (last visited Mar. 16, 2019).
[372] *16,067,208 Metric Tons of CO2 Injected as of January 3, 2018*, DEP'T OF ENERGY, https://www.energy.gov/fe/16067208-metric-tons-co2-injected-january-3-2018 (last visited Mar. 14, 2019).
[373] Rodosta et al., *supra* note 370, at 5581.
[374] *Standards Catalogue: ISO/TC 265; Carbon Dioxide Capture, Transportation, and Geological Storage*, INT'L ORG. FOR STANDARDIZATION, https://www.iso.org/committee/648607/x/catalogue/p/1/u/0/w/0/d/0 (last visited Mar. 14, 2019); *see also Carbon Dioxide Capture, Transportation and Geological Storage – Geological Storage*, INT'L ORG. FOR STANDARDIZATION, https://www.iso.org/standard/64148.html?browse=tc (last visited Mar. 14, 2019) (describing ISO standard for geologic sequestration and noting that it "establishes requirements and recommendations for the geological storage of CO_2streams, the purpose of which is to promote commercial, safe, long-term containment of carbon dioxide in a way that minimizes risk to the environment, natural resources, and human health").

Since the 2015 Final Rule, EPA has also approved a total of five monitoring, reporting and verification (MRV) plans under Subpart RR of its Greenhouse Gas Reporting Program regulations. These MRV plans apply to three EOR projects, one deep saline project and one acid gas injection project in non-producing areas of a hydrocarbon formation, in diverse regions of the United States.[375] Each plan includes, among other things, a delineation of monitoring areas; identification of potential leakage pathways and an assessment of likelihood of leakage; strategies for detecting and quantifying leakage; and quality assurance requirements.[376] These plans further support the adequately demonstrated nature of large-scale geologic storage and the ability of project sponsors to successfully complete the site-specific characterization and regulatory approvals needed for large-scale geologic storage, including in saline formations.

Lastly, international experience with geologic sequestration of CO_2 has also continued to progress since the finalization of the 2015 Final Rule. According to the Global CCS Institute's latest Global CCS Status Update, there are currently 18 large-scale CCS projects in operation around the globe, with an additional five under construction and twenty in various stages of development.[377] The total amount of CO_2 sequestered worldwide as of the end of 2017 is over 230 million metric tons, with approximately 65 percent of that total having been sequestered in the United States.[378] As of 2019, the total annual capture capacity of these large-scale projects is expected to exceed 40 million metric tons per year.[379] These large-scale projects include storage in deep saline formations—including projects not noted in the record for the 2015 Final Rule. Notable large-scale projects (both EOR and deep saline) include:[380]

- Gorgon (projected to store 3.4-4 million metric tons per year in deep saline)[381]
- Boundary Dam (2 million metric tons stored as of March 2018, for EOR and deep saline)
- Petra Nova (storing 1.4 million metric tons per year, for EOR)
- Sleipner (storing 0.85 million metric tons per year in deep saline)
- Snøhvit (storing 0.7 million metric tons per year in deep saline)
- Shute Creek (storing 7 million metric tons per year for EOR)
- Quest (storing 1 million metric tons per year, for EOR)

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[375] *See Subpart RR – Geologic Sequestration of Carbon Dioxide: Rule Information*, EPA, https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide (last updated Oct. 16, 2019). The five projects include Shute Creek (southwestern Wyoming); Core Energy (northern Michigan); Illinois Industrial CCS (Illinois); Hobbs Field (Permian Basin, New Mexico); and Denver Unit (West Texas). *Id.*
[376] *See, e.g.*, EPA, TECHNICAL REVIEW OF SUBPART RR MRV PLAN FOR CORE ENERGY NORTHERN NIAGARAN PINNACLE REEF TREND 13–15 (2018), https://www.epa.gov/sites/production/files/2018-10/documents/coreenergyniagaran_decision.pdf (summarizing EPA findings and corresponding Subpart RR requirements).
[377] GLOBAL CCS INSTITUTE, *supra* note 48, at 12.
[378] *Id.* at 20.
[379] *Id*.
[380] *See id.* at 17, 19, 21, 53, 75.
[381] This project is not yet operational, but anticipated to come online in 2019. *See id.* at 78.

- Petrobras Santos Basin (storing 2.5 million metric tons per year for EOR)
- Uthmaniyah (storing 0.8 million metric tons per year for EOR)
- Abu Dhabi CCS (storing 0.8 million metric tons per year for EOR)
- Century Plant (storing 8.4 million metric tons per year for EOR)
- Air Products Steam Methane Reformer (storing 1 million metric tons per year for EOR)
- Coffeyville Gasification Plant (storing 1 million metric tons per year for EOR)
- Lost Cabin Gas Plant (storing 0.9 million metric tons per year for EOR)

As further evidence of the feasibility of large-scale storage, and industry confidence in the viability of such storage projects, there are also several international large-scale storage projects currently in development and expected to come on-line within the next few years. These projects include:[382]

- CarbonNet (projected to come online in the 2020s, planned capacity of 1-5 million metric tons per year in dedicated storage in hydrocarbon formation)
- SouthWest Hub (projected to come online in 2025, planned capacity of 2.5-6 million metric tons per year in dedicated storage in sandstone formation)
- Norway Full Chain CCS (projected to come online in 2023-2024, planned capacity of 0.8 million metric tons per year in dedicated storage in sandstone formation)
- Port of Rotterdam CCUS Backbone Initiative (projected to come online in 2021, planned capacity of 2-5 million metric tons per year in depleted oil and gas fields)

3. The Proposed Rule Presents No Evidence Warranting a Change in EPA's Conclusions Regarding Geographic Availability

As described below, EPA's Proposal presents no new evidence that would warrant a change in the agency's prior conclusion that geologic storage opportunities are sufficiently available and demonstrated to support the determination that partial CCS is the BSER. The agency does not significantly alter EPA's estimate of the total geologic storage capacity available in the United States or the distribution and geographic extent of that capacity.[383] Moreover, the agency points to no new developments or information indicating that geologic storage of CO_2 at the scales contemplated by the current NSPS is infeasible. Appearing to recognize this, the Proposal offers only the speculative conclusion that geologic storage "*may* not be as widely geographically available as assumed in the 2015 analysis."[384] It would be arbitrary for EPA to reverse its determination that partial CCS is "adequately demonstrated" on the basis of unfounded, asserted uncertainties about the feasibility of geologic storage—especially when EPA's record for the Proposal confirms its prior conclusions that large-scale storage is widely

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[382] *See* GCCSI, CO2RE Facilities Database, https://co2re.co/StorageData (last visited Mar. 17, 2019).
[383] Proposal, 83 Fed. Reg. at 65,441 (updates to information considered in the 2015 Rule "do not significantly change the EPA's understanding of which areas are amenable to GS").
[384] *Id.* at 65,442 (emphasis added).

available and adequately demonstrated.[385] As the D.C. Circuit has held, "EPA cannot reject the 'best available' evidence simply because of the possibility of contradiction in the future by evidence unavailable at the time of the action—a possibility that will always be present."[386] Likewise, EPA cannot base its revised BSER determination "on the basis of a guess about what the facts might be."[387]

a. EPA Has Not Demonstrated any Significant Revision to Overall Geologic Storage Capacity and Extent.

As EPA itself concedes in the Proposal, the information that has become available since the finalization of the 2015 Final Rule does "not significantly change the EPA's understanding of which areas are amenable to [geologic storage]."[388] Indeed, the Proposal acknowledges that DOE updated its Carbon Storage Atlas in 2015 to reflect additional characterization and assessment studies conducted by DOE and the Regional Carbon Sequestration Partnerships. Further, the Proposal recognizes that the updated Atlas *increased* the low-end estimate of available deep saline storage capacity by over 13 percent, to 2,379 billion metric tons.[389] In the same updated Atlas, DOE's low-end estimate of *total* CO_2 storage capacity (including EOR and unmineable coal seams) increased by over 9 percent in the latest update, to 2,600 billion metric tons.[390] Likewise, the Proposal's updated assessment of the geographic distribution of these storage resources—which is based on the Atlas—shows that 38 states have access to geologic storage, a minimal change from EPA's prior analysis.[391]

In the Proposal, EPA presents no specific information that calls into question DOE's assessment of available storage capacity, or other information EPA relied upon in the 2015 Final Rule with respect to geographic availability of CCS. Instead, the Proposal offers a generalized concern that the Carbon Storage Atlas contains an estimate only of technically feasible storage areas, and does not account for site-specific regulatory or economic constraints that might make particular geologic storage areas costly or difficult to utilize.[392] In addition, the Proposal noted that EPA's updated assessment of the total area available for geologic storage has declined by 4 percent relative to the 2015 Final Rule.[393] As explained below, neither of these rationales constitutes a well-reasoned justification for determining that partial CCS is not sufficiently available to serve as the BSER.

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[385] *See Mississippi v. EPA*, 744 F.3d 1334, 1357 (D.C. Cir. 2013) ("Indeed, it is a familiar principle that agencies may not 'merely recite the terms substantial uncertainty as a justification for [their] actions'; instead, they must explain the evidence which is available, and must offer a rational connection between the facts found and the choice made." (quoting *State Farm*, 463 U.S. at 52 (internal quotation marks omitted) (alteration in original))).
[386] *Chlorine Chemistry Council v. EPA*, 206 F.3d 1286, 1290–91 (D.C. Cir. 2000). As noted above, *supra* note 358, the SAB Work Group found that EPA had used "best available science" in determining that saline storage of CO_2 was feasible and efficacious.
[387] *Small Refiner Lead Phase Down Task Force v. EPA*, 705 F.2d 506, 531 (D.C. Cir. 1983).
[388] Proposal, 83 Fed. Reg. at 65,441.
[389] *Id.* at 65,441 n.77.
[390] *NETL's 2015 Carbon Storage Atlas Shows Increase in U.S. CO2 Storage Potential*, DEP'T OF ENERGY (Sept. 28, 2015), https://www.energy.gov/fe/articles/netl-s-2015-carbon-storage-atlas-shows-increase-us-co2-storage-potential.
[391] Memorandum from EPA on Geographic Availability of Geologic Sequestration, at 4 (2018) [hereinafter 2018 Memo on Geographic Availability] (there were 39 states with availability in 2015 analysis).
[392] Proposal, 83 Fed. Reg. at 65,441.
[393] 2018 Memo on Geographic Availability, *supra* note 391, at 4.

First, EPA already considered and correctly rejected concerns about site-specific constraints on geologic storage in the context of the 2015 Final Rule. As noted above, EPA specifically recognized in the preamble to the 2015 Final Rule and in its response to comments that "[p]roject- and site-specific factors do influence where CO_2 can be safely sequestered."[394] However, EPA appropriately found that partial CCS is "adequately demonstrated" and that the current NSPS is readily achievable notwithstanding such project- or site-specific factors. As EPA explained in the 2015 Final Rule, the NSPS applies only to newly constructed units that have extensive flexibility with respect to siting. In light of the nationwide availability of both geologic sequestration storage sites, the feasibility of utilizing existing and new pipeline infrastructure to deliver CO_2 to distant sequestration sites, and the nationwide availability of electric transmission infrastructure, EPA found no reason to believe that a newly constructed EGU will find it infeasible to locate in such a way as to implement partial CCS.[395] Moreover, EPA recognized that there are systems other than partial CCS that would enable new steam EGUs to comply with the NSPS.[396]

EPA further observed in the 2015 Final Rule that the agency's experience in administering the UIC well injection program, and in granting permits for injection wells for geologic storage of CO_2, indicates that site-specific characterization issues can be identified and overcome. EPA noted that the "site characterization requirements and permit review process for Class VI wells provide a comprehensive framework to ensure sites are suitable for long-term storage of CO_2."[397] EPA acknowledged that site characterization requires "time and care to perform sufficiently," but noted that new steam EGUs have long planning, permitting, and construction times and that at least two geologic sequestration projects (including one involving a steam EGU) had already demonstrated the ability to successfully characterize a sequestration site and obtain the needed Class VI permits. [398] On the basis of this concrete experience, EPA concluded that "the current state of characterization of potential geologic sequestration sites would not be a barrier to CCS."[399]

The Proposal fails to acknowledge these reasons for determining that the current NSPS is achievable, much less explain why the agency's prior reasoning was incorrect. The Proposal does not offer any record evidence or examples to justify its vague asserted concerns. This failure renders EPA's proposed reversal of its conclusions regarding geographic availability arbitrary and capricious.[400]

The Proposal's minor adjustments to the total area of the country available for geologic storage are likewise an arbitrary and capricious rationale for reversing the BSER determination in the 2015 Final Rule. Even assuming *arguendo* that the exclusion of unmineable coal seams is justified (and as explained below, it is not), the Proposal fails to explain why a four percent

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394 2015 Final Rule, 80 Fed. Reg. at 64,581; *see also* RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-48 to -50 (acknowledging and responding to comments raising concerns about site-specific factors that might complicate geologic storage).
395 RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-50 (Response 6.3-81).
396 *Id.* at 6-53 (Response 6.3-86).
397 *Id.* at 6-58 (Response 6.3-91).
398 *Id.*
399 *Id.*
400 *Fox TV Stations*, 556 U.S. at 515.

reduction in total geographic storage area is substantial enough to render the current NSPS unachievable or exorbitantly costly. Indeed, the Proposal itself notes that geologic storage is still available in 38 states and that the updated information EPA has considered "do[es] not significantly change the EPA's understanding of which areas are amenable to [geologic storage]."[401] Neither does the Proposal revisit, much less rebut, EPA's observation in the 2015 Final Rule that many of the states that are not home to potential geologic storage sites have state law restrictions or other limitations that would independently impede the construction of new coal-fired steam EGUs.[402]

Lastly, the Proposal fails to consider the sheer scale of potential geologic storage resources in the United States, which is important context in considering the geographic availability of CCS. According to the Economic Impact Analysis for the Proposal, a hypothetical steam EGU with a capacity of 600 GW would capture approximately 1.1 million tons of CO_2 (1 million metric tons) per year if it were to implement partial CCS to comply with the current NSPS.[403] Even assuming that the plant operates at this capacity factor for a period of 50 years, the amount of storage capacity such a plant would require is only 0.002% of DOE's revised *low-end* assessment of total geologic storage capacity in the United States.[404] As EPA notes in the economic impact analysis accompanying this Proposal, few new unplanned coal-fired units are expected at the time of this rulemaking[405]—meaning that even the cumulative demand for geologic storage associated with the 2015 Final Rule will still be a very small share of the overall available resource. Thus, even if regulatory or economic constraints ultimately make certain portions of the technically available geologic storage resource unviable, the total amount of capacity (and land area) that is geologically available for storage is so vast that it is vanishingly unlikely that a new steam EGU would lack access to *any* suitable storage area.

4. EPA Arbitrarily Concludes that Large-Scale Storage in Deep Saline Formations Is Inadequately Demonstrated.

The Proposal also questions whether large-scale saline storage has been adequately demonstrated, arguing that "saline storage has not yet been demonstrated to be available . . . at all locations."[406] The Proposal acknowledges that large-scale deep saline storage is taking place at the Illinois Basin Decatur project, but argues that the project "has not yet proven that [geologic storage] in saline formations can be done throughout the United States (at scale) in wide geographic regions with highly diverse geologic conditions."[407] The Proposal adds that "[t]he project is sized at one million metric tons per year and may not demonstrate the full application of saline storage necessary for a large power project."[408]

[401] 2018 Memo on Geographic Availability, *supra* note 391, at 2.
[402] *See* 2015 Response to Comments, 6-75; 2015 Geographic Availability TSD at 1; 2015 Final Rule, 80 Fed. Reg. at 64576.
[403] NSPS ECONOMIC IMPACT ANALYSIS, *supra* note 10, at 2-3, -4.
[404] This figure was obtained by multiplying the 1 million metric ton per year capture requirement by 50, and dividing the result by the total low-end storage estimate of 2,600 billion metric tons.
[405] NSPS ECONOMIC IMPACT ANALYSIS, *supra* note 10, at 3-1.
[406] Proposal, 83 Fed. Reg. at 65,442.
[407] *Id.*
[408] *Id.*

This analysis of deep saline storage arbitrarily and capriciously ignores contradictory evidence in the record for the Proposal, as well as other information indicating that large-scale deep saline storage is feasible and well-demonstrated. To begin, the Proposal incorrectly states that the scale of the Archer Daniels Midland/Illinois Basin Decatur Project does not correspond to the level of saline storage necessary for a large power project. As noted above, EPA's own EIA for the Proposal suggests that a hypothetical 600 MW power plant constructed in compliance with the 2015 Final Rule would capture approximately 1 million metric tons of CO_2 per year—a level of capture that is identical to the annual amount of CO_2 sequestered at the Archer Daniels Midland project.[409] The Proposal's argument that the Archer Daniels Midland project is of insufficient scale to be relevant to a large power project is thus simply incorrect.

Moreover, the Archer Daniels Midland project is not the only deep saline project that has demonstrated large-scale storage of CO_2 commensurate with the needs of a new steam EGU. As noted above, two large EGU projects—Boundary Dam and Petra Nova—are currently sequestering CO_2 at commercial scale; the Boundary Dam project has captured approximately 2 million metric tons of CO_2 since commencing operations, and sequestered it in a combination of EOR and deep saline storage sites.[410] Further, the Aquistore saline storage site associated with Boundary Dam reported in 2017 that it has demonstrated the ability to receive 2,100 metric tons of CO_2 per day (close to 767,000 metric tons per year).[411] Likewise, Shell's Quest project in Canada sequestered 3 million metric tons of CO_2 in a saline formation between the start of operations in 2015 and June 2018 (a storage rate of approximately one million metric tons per year), and continues to operate successfully.[412] The Sleipner and Snøhvit projects are both large-scale deep saline storage projects that have been operating successfully for decades, and sequester CO_2 at rates of 850,000 and 700,000 metric tons of CO_2 per year, respectively.[413] And Chevron's Gorgon project in Australia is expected to come online in 2019, sequestering 3.4 to 4 million metric tons of CO_2 per year in a deep saline formation.[414] These projects all demonstrate that large-scale storage of CO_2 in saline formations, including from large power projects, is feasible.

The Proposal also argues that the Archer Daniels Midland project "only reflects the feasibility of saline injection and storage at one location in the United States," suggesting that saline storage can only be considered adequately demonstrated if it is "done throughout the United States (at scale) in wide geographic regions with highly diverse geologic conditions."[415] This claim ignores the multiple lines of evidence that support the technical feasibility of large-scale saline storage in diverse regions—including not just the projects described above, but the common geologic features that saline formations share with EOR sites. A 2005 special report by

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[409] *See id.* (noting that the Archer Daniels Midland project is scaled at one million metric tons per year); NSPS ECONOMIC IMPACT ANALYSIS, *supra* note 10, at 2-3 (noting that an illustrative CCS-equipped power plant would capture 1.1 million short tons per year, equivalent to 1 million metric tons).
[410] GLOBAL CCS INSTITUTE, *supra* note 48, at 17.
[411] AQUISTORE, AQUISTORE PROJECT ANNUAL REPORT 2016 at 5 (2017), http://aquistore.ca/+pub/AQ%20Annual%20Report%202016%20Final.pdf.

[412] GLOBAL CCS INSTITUTE, *supra* note 48, at 18, 24.
[413] *Id.* at 75.
[414] *Id. at 78.*
[415] 2018 Memo on Geographic Availability, *supra* note 391, at 2.

the Intergovernmental Panel on Climate Change (IPCC)—which is cited several times in the preamble to the 2015 Final Rule—notes that geologic storage sites occur in sedimentary formations that have undergone only minor tectonic shifts, are at least 1,000 meters thick, and have adequate seals to allow for injection and trapping of CO_2. [416] The report notes that oil and gas reservoirs are just a "subset" of these sedimentary formations, with deep saline formations and unmineable coal seams representing two other prominent examples. [417] DOE likewise noted in its most recent Carbon Storage Atlas that "[o]il and natural gas reservoirs are often saline formations that have traps and seals that allowed oil and gas to accumulate over millions of years."[418] Indeed, DOE observes that natural gas has frequently been injected into saline formations for storage, and that "the experience and technologies associated with the commercial saline formation storage of natural gas are applicable to CO_2."[419]

The well-understood geology of CO_2 sequestration in sedimentary formations, together with experience gathered through the many large-scale projects described above, is a strong indication that saline storage is technically feasible—not just in the areas where it has already been demonstrated, but in the wide geographic areas that DOE has determined have suitable geology for saline sequestration.

Moreover, the Proposal provides no explanation as to why this clear evidence of the technical feasibility of saline storage is insufficient. Nor does the Proposal point to any information indicating that saline storage is infeasible in the United States or anywhere else. "EPA cannot reject the 'best available' evidence simply because of the possibility of contradiction in the future by evidence unavailable at the time of the action—a possibility that will always be present."[420]

Further, EPA's suggestion that saline storage can only be considered adequately demonstrated *after* it has been implemented "throughout the United States" runs contrary to case law explaining when a system of emission reduction can be considered "adequately demonstrated" under section 111. The courts have clearly held that section 111 allows EPA to make "reasonable extrapolations" about the performance of a technology based on its performance in related contexts.[421] Further, the case law makes clear that section 111 does not require that a system be "in actual, routine use somewhere" in order to be designated the BSER.[422] In the context of geologic sequestration, these holdings make clear that EPA is *not* required to wait until geologic sequestration is in "routine use" and demonstrated "throughout the United States" in order to determine that partial CCS is the BSER—especially when the information in the record clearly supports the feasibility of geologic sequestration, and EPA has

[416] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CARBON DIOXIDE CAPTURE AND STORAGE 94, 200 (2005) [hereinafter IPCC CCS Report].
[417] *Id.* at 94.
[418] 2015 CARBON STORAGE ATLAS, *supra* note 367, at 24.
[419] *Id.* at 26; *see also* IPCC CCS Report, *supra* note 416, at 60 ("Injection of CO_2 underground would involve similar technology to that employed by the oil and gas industry for the exploration and production of hydrocarbons, and for the underground injection of waste as practised in the USA.").
[420] *Chlorine Chemistry Council*, 206 F.3d at 1290–91.
[421] *See Lignite Energy Council*, 198 F.3d at 933–34 (D.C. Cir. 1999) (citing *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1054 n.70 (D.C. Cir. 1978)).
[422] *Portland Cement Ass'n*, 486 F.2d at 391.

presented no concrete evidence suggesting that sequestration is infeasible. Indeed, it is contrary to the technology-forcing purpose of section 111[423] —and to the agency's obligation to reduce emissions from new sources to the maximum practicable degree[424] —for EPA to discard a highly effective BSER such as partial CCS in favor of a weaker system, simply because partial CCS is not in "routine use."

5. EPA's Proposal to Disregard Geologic Storage Capacity in Unmineable Coal Seams Is Arbitrary.

The Proposal entirely disregards geologic storage capacity in unmineable coal seams, based on EPA's belief that "additional research using larger scale and longer duration tests in unmineable coal seams is needed to improve the understanding and modeling of CO_2 storage in coals." [425] This decision is arbitrary in light of the numerous successful pilot projects mentioned in the TSD accompanying the Proposal (including the Allison Unit pilot project in New Mexico, which injected a total of 270,000 tons of CO_2 over a six year period); [426] DOE's continued inclusion of unmineable coal seams in its most recent Carbon Storage Atlas, which is a strong indication of DOE's judgment that sequestration in unmineable coal seams is technically feasible; [427] and the significant progress made in understanding the storage capacity and injection dynamics of coal seams.[428]

Although the Proposal notes that large-scale injection of CO_2 in coal seams can lead to swelling of coal, the literature also suggests that there are available technologies and techniques to compensate for the resulting reduction in injectivity.[429] Further, the Proposal does not explain why reduced injectivity cannot be anticipated and accommodated in sizing and characterizing prospective sequestration sites.

iii. It is Arbitrary for EPA Not To Consider Coal-By-Wire as a Solution to Storage Concerns

The Supreme Court has been clear that, when an agency wishes to adopt a "new policy [that] rests upon factual findings that contradict those which underlay its prior policy . . . [i]t would be arbitrary or capricious to ignore such matters."[430] Yet in "propos[ing] to rescind [its]

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[423] *Sierra Club*, 657 F.2d at 364.
[424] *Essex Chem. Corp.*, 486 F.2d at 437.
[425] Proposal, 83 Fed. Reg. at 65,442.
[426] 2018 Memo on Geographic Availability, *supra* note 391, 2–3.
[427] 2015 CARBON STORAGE ATLAS, *supra* note 367 , at 27.
[428] *See* Xiachun Li & Zhi-Ming Fang, *Current Status and Technical Challenges of CO_2 Storage in Coal Seams and Enhanced Coalbed Methane Recovery: An Overview*, 1 INT. J. COAL SCI. TECH. 93, 93 (2014) ("Due to the past two decades' study, great progresses have been made in ECBM technology, especially in evaluations of CO_2 storage capacity in coal seams, laboratory studies related to CO_2-ECBM mechanisms, modelings of CO_2-ECBM process and also we have conducted some pilot/demonstration tests."); *see also* 2018 Memo on Geographic Availability, *supra* note 391, 3 (discussing projects that have "demonstrated some degree of potential for [geologic storage] in unmineable coal seams.").
[429] Li & Fang, *supra* note 428, at 99 (suggesting existing technologies that can be used to address injectivity reduction in unmineable coal seams).
[430] *Fox TV Stations*, 556 U.S. at 515; *see also id.* at 537 (Kennedy, J., concurring) ("Where there is a policy change the record may be much more developed because the agency based its prior policy on factual findings. In that instance, an agency's decision to change course may be arbitrary and capricious if the agency ignores or countermands its earlier factual findings without reasoned explanation for doing so.").

finding that partial CCS satisfies the BSER criteria" in part because "partial CCS is not widely geographically available,"[431] EPA utterly ignores a key consideration that underlay its 2015 assessment: the availability of coal-by-wire, by which a coal-fired power plant serves demand in another location. Because a coal plant need not be located near the source of electricity demand, coal plants can be located where CCS storage is available and provide electricity to the regional grid associated with that storage location. Coal-by-wire increases the geographic availability of the BSER by enabling coal plants utilizing CCS to reach populations without nearby sequestration sites. Consumers can be served by transmission lines connected to distant coal plants, which can then use CO_2 pipelines to cover any remaining distance to sequestration sites. This expands the area of the country that can be reached by coal plants that use CCS to meet the current standard, further demonstrating the standard's achievability.

For the 2015 NSPS, EPA considered coal-by-wire in the proposal, final rule, and several associated documents. For instance, in the 2014 proposal, when discussing the geographic availability of partial CCS at reasonable cost, EPA stated

> [I]t is important to note that coal-fired power plants that build in any particular location may serve demand in a wide area. There are many examples where coal-fired power generated in one state is used to supply electricity in other states. For instance, historically, nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah. In another example, Idaho Power, which serves customers in Idaho and Eastern Oregon, meets its demand in part from coal-fired power plants located in Wyoming and Nevada.[432]

EPA also noted the availability of coal-by-wire in the 2015 Final Rule. For example, the agency observed:

> [A]s discussed in the proposal, electricity demand in states that may not have geologic sequestration sites may be served by coal-fired electricity generation built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines. This method, known as "coal-by-wire," has long been used in the electricity sector because siting a coal-fired power plant near the coal mine and transmitting the generation long distances to the load area is generally less expensive than siting the plant near the load area and shipping the coal long distances.[433]

Accompanying the 2015 Final Rule, EPA released a technical support document examining the geographic availability of geologic sequestration of carbon dioxide.[434] This document included a seven-page assessment of the availability of coal-by-wire in regions of the country for which proximate geologic sequestration sites had not been identified. For these regions, EPA analyzed, among other factors, the existing electric transmission infrastructure,

[431] Proposal, 83 Fed. Reg. at 65,445.
[432] 2014 Proposed Rule, 79 Fed. Reg. at 1478.
[433] 2015 Final Rule, 80 Fed. Reg. at 64,582–83.
[434] 2015 Memo on Geologic Availability, *supra* note 274.

current resource mix, and likelihood that the NSPS would, in practice, inhibit new coal-fired power plants.[435]

In three separate chapters of the Response to Comments on the 2015 Final Rule, EPA pointed to coal-by-wire to show that the rule did not impose geographic constraints.[436] And EPA mentioned coal-by-wire yet again when denying petitions to reconsider the 2015 Final Rule.[437]

The agency's total failure to consider the availability of coal-by-wire in the Proposal is arbitrary and unlawful. A candid examination of the available facts and data would reaffirm what EPA repeatedly found when formulating the 2015 NSPS: that the availability of coal-by-wire only further amplifies the siting flexibility for new coal-fired EGUs using partial CCS. Although section 111 does not require that a BSER be available in any given geographic location, EPA reasonably relied upon the availability of "coal-by-wire" (and other factors) to determine that the current NSPS "can be met anywhere in the country."[438] As noted in Section II.F.i, nationwide availability is not a prerequisite or even a relevant criterion in selecting the BSER. But the Proposal's focus on nationwide availability, while rejecting readily available mechanisms and careful EPA analysis that would support such availability, is a further example of the Proposal's unsupported and unlawfully biased approach, designed to result in the weakest possible BSER.

iv. EPA's Statements About Water Requirements for CCS-equipped EGUs Are Arbitrary and Capricious

EPA proposes to change its determination of partial CCS as BSER because it now finds that water availability concerns limit the overall geographic availability of CCS. As noted above, section 111 does not require that a BSER be universally available or be available at similar costs across the country. In any event, EPA provides scant new analysis or data to support a reversal of its previous stance that the water requirements for CCS are manageable. Estimating water availability drawing on annual average rainfall totals, EPA observes that, "the Western U.S.. . . has lower amounts of water available for EGUs."[439] It also alleges that "a comparison of areas of the country with lower rainfall amounts shows considerable overlap with areas of the country with sequestration sites."[440] As discussed below, this superficial discussion fails to show water availability is truly a limitation for owners and operators complying with the 2015 Final Rule—particularly in light of the siting flexibility that new EGUs generally enjoy and the relatively small number of EGUs that are expected to be subject to this standard

EPA's claim that lower average rainfall in the West renders partial CCS unachievable is arbitrary and unsupported. EPA does not explain in the Proposal why average rainfall over a broad region without considering water available in rivers, lakes, and groundwater reservoirs that power plants and industrial facilities actually utilize—is relevant at all to assessing the availability of water for partial CCS-equipped EGUs. Further, EPA never attempts a quantitative

[435] *See id.* at 12–15.
[436] *See* RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, 2-63, 2-112, 3-230, 3-245, 9-26.
[437] *See* RECONSIDERATION DENIAL, *supra* note 74, at 38 (2016).
[438] RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 9-26.
[439] Proposal, 83 Fed. Reg. at 65,444.
[440] Proposal, 83 Fed. Reg. at 65,444.

analysis of overall water availability in the West in the context of the actual water demands of new EGUs (or other sources of water demand). Taken to its logical conclusion, EPA's reasoning in the Proposal would lead EPA to arbitrarily reject *any* emission reduction system in *any* sector that increased water by *any* amount—a ludicrous outcome in light of the many pollution control systems that utilize water to at least some extent. EPA fails to provide any detailed factual analysis about the extent to which water availability is truly a barrier to CCS.

Moreover, the fact that the Western part of the United States is a more arid region with less rainfall was known to EPA when it finalized the 2015 standard. This issue was raised in comments, as noted in EPA's Response to Comments.[441] EPA addressed this issue in the preamble to the 2015 Final Rule—reducing anticipated water use associated with the final standard by finalizing a BSER that included only partial CCS. It found that,

> a new SCPC unit that implements 16 percent partial CCS to meet the final standard would see an increase in water consumption (the difference between the predicted water withdraw and discharge) of about 6.4 percent compared to an SCPC with no CCS and the same net power output. By comparison, a unit implementing 35 percent CCS to meet the proposed emission limitation of 1,100 lb CO_2/ MWh-g would see an increase in water consumption of 16.0 percent and a new unit implementing full (90 percent) CCS would see an increase of almost 50 percent.[442]

EPA thus accounted for water usage when determining the current BSER to be reasonable.

EPA further noted there were additional opportunities to reduce water usage. EPA pointed to the SaskPower Boundary Dam Unit #3 project, which "captures water from the coal and from the combustion process and recycles the captured water in the process, resulting in decreased need for withdrawal of fresh water."[443] EPA also noted IGCC was available as a compliance option and had significantly decreased water use requirements (20 percent less than a new SCPC unit without CCS and almost 25 percent less than a new SCPC unit meeting the final standard).[444] By contrast, the Proposal arbitrarily inflates water consumption requirements for CCS-equipped EGUs and fails to take into account available technologies and approaches for reducing those water requirements even further.

1. EPA's Data Arbitrarily Inflates Water Consumption Requirements for CCS-Equipped EGUs

EPA's new analysis considering different configurations for plants burning low rank coal is flawed and overestimates the water requirements for CCS technology. In the Proposal, EPA claims the previous analysis underestimated water requirements for partial CCS that because it was based on a bituminous-fired EGU with a wet scrubber and a cooling tower. Though the Proposal admits that this is a "common configuration," EPA claims it does not adequately

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[441] *See* EPA, RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 6-50, 6-71, 6-239.
[442] 2015 Final Rule, 80 Fed. Reg. at 64,592-93. EPA now corrects the 6.4 percent figure to 7.7 percent. Proposal, 83 Fed. Reg. at 65,443 n.87.
[443] 2015 Final Rule, 80 Fed. Reg. at 64,593.
[444] *Id.*

represent all possible boiler configurations and air pollution control devices.[445] EPA claims that in the Western United States and more arid climates, configurations minimizing water usage may be used, such as a subbituminous-fired PC unit with spray drying or a fluidized bed unit and a cooling tower. For such a unit, EPA estimates that the percentage increase in water use is approximately four times higher, around 28 percent.[446] Specifically, EPA finds implementing 16 percent CCS increases water consumption for a SCPC unit burning bituminous coal from 7.4 to 7.9 gpm/MWnet (7.7 percent); implementing 26 percent CCS increased water consumption for a SCPC burning low rank coal from 3.8 to 4.9 gpm/MWnet (28 percent); and implementing 25 percent CCS increased water consumption from a SCCFB burning low rank coal from 3.3 to 4.3 gpm/MWnet (31 percent).[447]

However, EPA's calculation for EGUs burning low rank coal contains a fatal flaw. EPA explains:

> To estimate the increased water consumption for low rank coal-fired EGUs, the EPA used the NETL partial capture report for bituminous coal-fired EGUs to determine the increased water requirements per amount of CO_2 captured. The EPA then applied the increased water use relationship to the 2011 baseline report that included model plants burning low rank coal.[448]

The baseline figures then appear to come from NETL's March 2011 report, which is based on a model plant with a parallel wet/dry condenser.[449] In such a system "half of the turbine exhaust steam is condensed in an air-cooled condenser and half in a water-cooled condenser."[450] On the other hand, the figures EPA uses to determine the additional water requirements imposed by CCS come from a separate NETL report that assumes a conventional wet cooling tower.[451] Most of the additional water requirements from implementing CCS derive from cooling tower makeup water, thus assumptions about the type of cooling system play a central role in determining what the water requirements of a CCS-equipped EGU will be.[452] EPA itself notes that absolute water requirements for implementing CCS do not vary much between various boiler types. By assuming hybrid cooling as the baseline, but wet cooling in the CCS case, EPA vastly inflates the increase in water requirements for the SCPS with low rank coal case.

2. EPA's New Focus on Percentage Increase in Water Consumption Is Arbitrary

[445] Proposal, 83 Fed. Reg. at 65,443.
[446] *Id.*
[447] Memorandum from EPA to EGU NSPS Docket (EPA-HQ-OAR-2013_0495) on Review of the Water Consumption and Availability Impacts on the Viability of Carbon Capture and Storage Projects unnumbered p. 3 (Dec. 2018) [hereinafter Water Availability Memo].
[448] Proposal, 83 Fed. Reg. at 65,443.
[449] NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 3b: Low Rank Coal to Electricity: Combustion Cases, DOE/NETL-2011/1463 31 (Mar. 2011).
[450] *Id.*
[451] NETL, Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, DOE/NETL-2011/1498 35 (Sep. 19, 2013 revision).
[452] *Id.*

EPA's focus on percentage increase in water consumption instead of looking at the absolute water requirements heightens the arbitrariness of its conclusions about the water demands associated with partial CCS. The figures that EPA presents show significantly lower baseline water requirements for plants burning low rank coal, compared to the configuration assumed in the 2015 Final Rule. The Proposal's new assumption that plants subject to the 2015 Final Rule are likely to use low rank coal inflates water consumption requirements because low rank coal requires a higher level of CCS, and increased energy and water requirements, to deal with increased CO_2 emissions. But even so, EPA's own inflated analysis shows overall water requirements lower than for the model plant burning bituminous coal (with or without CCS). Thus, the only new analysis EPA presents suggests that CCS could be implemented with lower water requirements than EPA previously considered. EPA's focus on the larger percentage increase is indicative only of the lower baseline, and misleadingly obscures the fact that the absolute water consumption of a subbituminous-fired EGU with partial CCS is 38 percent lower than the bituminous wet-cooled plant EPA assumed in the 2015 Final Rule. It is arbitrary and capricious for EPA to overturn its previous finding that water consumption to implement CCS could be reasonably managed when it presents no information that more water is needed for use in CCS systems than previously determined.

3. EPA Provides No Support for its Conclusion that the Costs of Meeting Increased Water Demand for CCS are Unreasonable

EPA provides no information about what the additional costs to owner/operators would be, or their ability to manage those costs. EPA baselessly asserts that under its flawed, inflated analysis, "the percent increase in water use for EGU's burning low rank coal is four times as large as for bituminous-fired EGUs" and that this "is so great that it *could* be prohibitively expensive for developers to secure sufficient quantities of water in arid regions of the country."[453] But EPA does not say what amount of additional cost such an EGU would incur, much less explain why that would be "prohibitively expensive." EPA cannot overturn the current standards based on such speculative reasoning devoid of any factual basis.

4. EPA' Assumption that Dry Cooling is Incompatible with CCS Technology is Arbitrary

EPA states that the demand for dry cooling systems could increase in the future and this limits the feasibility of CCS as BSER because "EPA is unaware of any demonstration, pilot, or large-scale projects using dry cooling technologies with carbon capture technologies."[454] EPA misrepresents both the desirability of dry cooling and it being an impediment to CCS. First, EPA admits that currently only four plants total in the United States utilize dry cooling.[455] Dry cooling systems are about 3 to 4 times as expensive as a wet recirculating system[456], because of their high capital costs and because they require more energy to run,[457] they are unlikely to be utilized

[453] Proposal, 83 Fed. Reg. 65,443 (emphasis added).
[454] Proposal, 83 Fed. Reg. at 65,443.
[455] Water Availability Memo at unnumbered p. 5.
[456] NETL, Water Requirements for Existing and Emerging Thermoelectric Plant Technologies, DOE/NETL 402/080108 at 5 (April 2009 revision).
[457] Some U.S. electricity generating plants use dry cooling, EIA (Aug. 29, 2018), https://www.eia.gov/todayinenergy/detail.php?id=36773.

at new plants in the future unless required by regulation. While EPA notes that dry cooling is more widely in use by NGCC units, that is irrelevant and does not correspond to its use by coal-fired EGUs because NGCC plants require lower amounts of cooling per megawatthour than coal plants, making it a more economical option for them.[458] Overall among all thermoelectric generating units, only 3 percent utilize dry or hybrid cooling systems.[459] EPA, of course, need not account for types of design which may not even occur in establishing NSPS.[460]

EPA is also wrong in both assumptions that dry cooling is incompatible with CCS technology [461] and that dry cooling would substantially increase water requirements.[462] When choosing where to site a plant and decide on plant configurations, owners/operators have the option of considering whether utilizing dry cooling to deal with water availability issues in an arid region makes economic sense. This was demonstrated by the proposed Tenaska Trailblazer Energy Center development. Though the plans to construct the plant were abandoned, Tenaska developed a report comparing potential cooling systems for the plant that shows less water intensive cooling options are viable for use with CCS.[463] The project was to be developed in Texas, in a semi-arid area, with annual rainfall averaging about 22 inches, and thus designing the plant to minimize water usage was a key consideration.[464] Tenaska considered dry cooling, full wet cooling, and hybrid cooling and found they were all technically feasible.[465] While dry cooling had the highest capital costs, it had the lowest operating and maintenance costs (and was the most economic option), and further reduced water usage to an average of 1 mgd (3,785 m3/d), compared to approximately 5 mgd (18,927 m3/d) for hybrid cooling and 11.7 mgd (44,289 m3/d) for wet cooling.[466] Tenaska in fact found that adding CCS to the dry-cooling configuration *decreased* water consumption compared to operating the pulverized coal plant alone because "the CC Plant includes an upfront cooling step that condenses combustion water vapor which is re-used in the PC Plant."[467] Tenaska further planned to reduce the water demand by "designing the remaining water systems for 10 cycles of concentration (associated with

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[458] *Id.*
[459] Some U.S. electricity generating plants use dry cooling, EIA (Aug. 29, 2018), https://www.eia.gov/todayinenergy/detail.php?id=36773.
[460] *Portland Cement Ass'n v. EPA*, 655 F. 3d 177, 190 (D.C. Cir. 2011) (EPA need not take into account "an entirely conjectural species" of design within source category); *see, also, Kennecott v. EPA*, 780 F. 2d 445, 454 (4th Cir. 1986) (EPA need not consider possible source designs that are not "in the process of being built or even contemplated," if such a source was built, "it can be designed to EPA specifications").
[461] *See, e.g.,* Zhai H and Rubin E S, A techno-economic assessment of hybrid cooling systems for coal- and natural-gas-fired power plants with and without carbon capture and storage Environ. Sci. Technol. 50 4127–34, 4133 (2016) ("Hybrid cooling, as an alternative to the conventional wet cooling technology, thus offers a promising option for future power plant designs.").
[462] Proposal, 83 Fed. Reg. at 65,443 ("However, carbon capture technologies are limited to using conventional wet cooling technologies. The EPA is unaware of any demonstration, pilot, or large-scale projects using dry cooling technologies with carbon capture technologies. Therefore, requiring CCS on a plant of this design would substantially increase the plant's water-use requirements.")
[463] Tenaska, COOLING ALTERNATIVES EVALUATION FOR A NEW PULVERIZED COAL POWER PLANT WITH CARBON CAPTURE (Aug. 2011).
[464] *Id.* at 1.
[465] *Id.* at 4.
[466] *Id.* at 5.
[467] *Id.* at 21-22.

titanium metallurgy) and the inclusion of the ZLD unit which provides a water recycle stream."[468]

The feasibility study released by the International CCS Knowledge Centre and SaskPower on the potential Shand Power Station also demonstrate how CCS can be utilized with dry cooling systems to drastically reduce water demand. The Shand Power Station is sited in an area with limited water availability such that additional water requirements "would be a regulatory hurdle, if possible at all."[469] The CCS design envisioned for it thus requires no additional water. The system would use a combination of wet and dry cooling, and "[t]he proposed heat-rejection design would eliminate the burden by requiring the use of water that has been condensed from the flue gas."[470] The study notes that this solution could be widely applied and is especially effective with use of high moisture low rank coals.[471]

Thus, owners and operators may rely on dry or hybrid cooling to deal with the water demands of CCS in areas with water stress. The use of dry cooling does not suggest that the additional water demands of CCS will be more burdensome than otherwise. Even at constant increase in absolute water requirements across plants equipped with wet, dry, or hybrid cooling systems (though as demonstrated in the Tesnaska example, it is possible that dry cooling could in fact reduce or have lower water requirements), the plant with dry cooling will experience the greatest percentage increase. This is obvious, and says nothing about the owner/operator's ability to deal with those additional water requirements at reasonable cost. The fact that the overall water consumption remains low, and significantly lower than at plants utilizing wet cooling, is the more salient point and allows for the use of dry cooling to address water availability issues.

5. EPA Fails to Consider the Myriad Options to Reduce Water Consumption for CCS, Even in Combination with Lignite Pre-Drying

EPA arbitrarily dismisses the possibility of recovering moisture from the flue gas to reduce water consumption at CCS-equipped EGUs. One option to reduce water consumption at a coal-fired power plant is to recover a portion of the water vapor present in the flue gas and reuse it to meet the plant's water demands.[472] As discussed in the 2015 Final Rule, SaskPower Boundary Dam Unit #3 recycles captured water to reduce water consumption. Now EPA claims that this method is unlikely to be utilized by owners/operators because they would be likely to dry the lignite prior to combustion, which would allow for less water that could be captured from the flue gas.[473] EPA's argument only pertains to lignite as higher-rank coal does not require

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[468] *Id.* at 26.
[469] International CCS Knowledge Centre, THE SHAND CCS FEASIBILITY STUDY PUBLIC REPORT 1 (Nov. 2018), https://ccsknowledge.com/pub/documents/publications/Shand%20CCS%20Feasibility%20Study%20Public%20_Full%20Report_NOV2018.pdf.
[470] *Id.* at 52.
[471] *Id.* at 12.
[472] *See, e.g.,* Bruce C. Folkedahl, et. al., Water Extraction from Coal-Fired Power Plant Flue Gas (Dec. 2006), https://www.osti.gov/servlets/purl/927112; Dexin Wang, Transport Membrane Condenser for Water and Energy Recovery from Power Plant Flue Gas Final Technical Report (Oct. 1, 2008-Mar. 31, 2012), https://www.osti.gov/servlets/purl/1064416;*see, also,* Barbara Carney, New Technology Will Recover Heat & Water from Flue Gas, POWER ENGINEERING (Aug. 23, 2016), https://www.power-eng.com/articles/print/volume-120/issue-8/features/new-technology-will-recover-heat-water-from-flue-gas.html.
[473] Proposal, 83 Fed. Reg. at 65,443 n.86.

drying because of its lower moisture content. Moreover, drying lignite coal pre-combustion can help reduce water consumption on its own, because it increases plant efficiency and reduces makeup water requirements for evaporative cooling towers.[474] According to one analysis, water reductions of 140,000 gallons per day could be achieved for a 537 MW lignite plant with pre-combustion drying .[475] Additionally, there are opportunities to capture water from the coal during the pre-drying process.[476] Thus, EPA's assertion that pre-drying lignite is incompatible with reducing water consumption at plants is arbitrary and capricious. Furthermore, lignite-fired plants are very rare; as discussed further below, EPA again rejects partial CCS on the basis of an extreme, rare circumstance without even demonstrating that there is any market interest in building a new lignite coal-fired plant.

EPA further ignores and minimizes that opportunities to reduce water consumption will only expand in the future.[477] It is arbitrary for EPA to not consider that continued advancements in CCS technology to increase energy and water efficiency will reduce water use requirements. The Global CCS Institute noted that comparing DOE studies done in 2013 and 2015 demonstrated large reductions in water consumption from CCS systems based on updated assumptions incorporating more advanced, less energy intensive CCS technology.[478] Thus, "[i]t is reasonable to assume that as capture technologies with further decreases in energy intensity are developed, additional water requirements will decrease as well."[479] Research from other parts of the globe where water availability is limited can be especially relevant to determining methods to reduce water consumption.[480]

6. EPA Fails to Consider that the Owners/Operators Will Already Take Water Availability into Account when Making Siting Decisions

Considering the large amounts of water needed to operate coal-fired power plants even without CCS technology, EPA never explains why the additional water requirements imposed by CCS would be a significant additional barrier when owners and operators will already be considering water availability in making siting decisions. Plant owners and operators are already

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[474] Edward Levy, et. al., Use of Coal Drying to Reduce Water Consumed in Pulverized Coal Power Plants at 11 (Jan. 2006).

[475] *Id.*

[476] *See, e.g.,* Xiaoqu Han, Integration of Organic Rankine Cycle with Lignite Flue Gas Pre-Drying for Waste Heat and Water Recovery from Dryer Exhaust Gas: Thermodynamic and Economic Analysis, 105 ENERGY PROCEDIA 1614-1621 (2017) (55.17 percent of water vapor can be recovered through flue gas pre-drying of lignite); IEAGHG, Evaluation and Analysis of Water Usage of Power Plants with CO2 Capture, Report 2010/05 1.4.1.2 (Mar. 2011) ("Significant amounts of water may be recovered from the process of coal drying").

[477] *See, e.g.,* Thomas J. Feeley, III et. al., Department of Energy/National Energy Technology Laboratory's Power Plant-Water R&D Program (detailing DOE and NETL's integrated research and development (R&D) effort to reduce freshwater use at power plants).

[478] Global CCS Institute, Water Use in Thermal Power Plants Equipped with CO2 Capture Systems at 13 (Sept. 2016), https://www.globalccsinstitute.com/resources/publications-reports-research/?search=Water+Use+in+Thermal+Power+Plants+Equipped+with+CO2+Capture+Systems+

[479] *Id.*

[480] *See, e.g.,* NETL, REDUCING FRESHWATER CONSUMPTION AT COAL-FIRED POWER PLANTS: APPROACHES USED OUTSIDE THE UNITED STATES (April 2011).

restricted in where they can site a coal-fired power plant based on water availability.[481] Concerns over water availability for thermoelectric use are only expected to increase as climate change further contributes to water stress.[482] This impacts future decisions about where, and whether, to build a coal versus natural gas fired power plant, or some other source. In a scenario where an owner/operator has made a decision to build a new coal-fired power plant, already taking into account water availability concerns, EPA provides no evidence or analysis to support the conclusion that the incremental additional water requirements for CCS would impose a significant additional barrier that could not be addressed using water savings methods addressed above. EPA cannot reject readily available partial CCS on the basis of the Proposal's unsubstantiated water availability assertions.

7. EPA's Analysis Arbitrarily Assumes the Worst-Case Scenario, and Provides No Justification that Water is Scarce near All Geologic Sequestration Sites

EPA's water availability analysis is further flawed, arbitrary, and capricious, because it relies on a number of unrealistic assumptions to create a worst-case. EPA assumes that an owner/operator will wish to site a less efficient lignite coal-fired power plant in an arid region where there is no water supply close to a geologic sequestration site. This assumes a higher rate of carbon capture will be necessary, increasing water requirements. However, then EPA argues the lignite would be pre-dried, without taking into account the resulting water and energy savings, focusing only on the lost opportunity to recover water from the flue gas post-combustion. Owners have discretion to determine the configuration of their plant, type of coal its uses, where they site the plant, the type of cooling system them employ, and whether they will install other water saving technology. EPA is not required to tailor standards to ensure that they are feasible in every and any remote scenario.[483] Owners have flexibility to determine a plant configuration that is of reasonable cost in its location.

In order to provide reasonable justification to overturn its previous finding, EPA must do more than say there appears to be overlap between areas with low precipitation and geological sequestration sites. EPA simply says that it made "a comparison" of "areas of the country with lower rainfall amounts" and "areas of the country with sequestration sites"[484] and provides high-level maps showing annual average precipitation across the United States with little detail.[485] EPA does not provide the data it analyzed to draw this conclusion, suggesting that EPA did no further analysis other than glancing at this map showing areas with low precipitation. EPA does not say what percentage overlap there was, or what the mean precipitation totals in such areas

[481] EPA, EnviroAtlas Fact Sheet, Thermoelectric Water Use: Consumption (Sept. 2017), https://enviroatlas.epa.gov/enviroatlas/DataFactSheets/pdf/ESN/Thermoelectricwateruseconsumption.pdf ("Because of the large water demand for cooling, thermoelectric plants tend to be sited along rivers and lakes.").
[482] Brekke, L.D., Kiang, J.E., Olsen, J.R., Pulwarty, R.S., Raff, D.A., Turnipseed, D.P., Webb, R.S., and White, K.D., 2009, Climate change and water resources management—A federal perspective: U.S. Geological Survey Circular 1331 at 11, http://pubs.usgs.gov/circ/1331/.
[483] *Portland Cement Ass'n v. EPA*, 655 F. 3d 177, 190 (D.C. Cir. 2011) (EPA need not take into account "an entirely conjectural species" of design within source category); *see, also, Kennecott v. EPA*, 780 F. 2d 445, 454 (4th Cir. 1986) (EPA need not consider possible source designs that are not "in the process of being built or even contemplated," if such a source was built, "it can be designed to EPA specifications").
[484] Proposal, 83 Fed. Reg. at 65,444.
[485] Water Availability Memo at unnumbered p. 5-6.

was, or what thresholds it even considers as "lower rainfall amounts," or any other specific data to suggest that there is indeed a widespread issue of low water resources (too low to support partial CCS even utilizing available methods to reduce water needs) near geological sequestration sites.

Even if it were the case, EPA fails to consider other methods to address such an issue. Coal by wire allows more flexible siting of coal-fired power plants if necessary. Further, owners can always utilize non-CCS compliance alternatives to meet the standards, and do not have to implement partial CCS if they find the water requirements too demanding. Given the relatively small number of new coal-fired EGUs that are anticipated to be built under this proposal, EPA has failed to show that water availability in the West would render the current standard unachievable even in arid parts of the country.

8. EPA's Statements Regarding IGCC Water Consumption Are Unsupported and Arbitrary

EPA's suggestion that use of IGCC cannot allay water use concerns is arbitrary and capricious. EPA now questions its previous finding that IGCC could substantially reduce water consumption for plants utilizing CCS because of purported new information concerning the Kemper IGCC Project. According to EPA, an independent engineering report found that initial estimates for water requirements were underestimated and a temporary new water storage tank was needed to increase water storage capacity.[486] This is merely one example and does not support EPA drawing a conclusion that IGCC technology does not significantly reduce water requirements. Additionally, the report suggests not that IGCC technology requires more water than originally estimated, but that the water filtration system installed at the plant to allow for recycling of water was experiencing problems.[487] There is no indication that these problems were permanent or would not have eventually been addressed. As EPA itself notes: "Since the project was not completed, EPA does not have information on the ultimate water use of this IGCC design."[488] However, EPA does have access to numerous studies that have concluded the water requirements of IGCC are much lower.[489]

9. EPA Failed to Consider Sub-Categorization

Finally, even if EPA determined water availability concerns were truly prohibitive to selecting partial CCS as the BSER in certain arid regions, the solution is not to implement a less desirable BSER nationwide but to exercise its discretion to issue separate standards based on differences in classes, types, and sizes of sources.[490] Even assuming *arguendo* that there was a constraint on a BSER in some areas of the country, the solution is not to select a BSER that is

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[486] Water Availability Memo unnumbered p. 4.
[487] Mississippi Public Service Commission, IM Monthly Report: Kemper IGCC Project 3, 9 (Apr. 2017) (Recovered Water Candle Filers not able to handle full flow due to solid carryover issues, new system is being tested to recover water for downstream use).
[488] Proposal, 83 Fed. Reg. at 65,444.
[489] *See, e.g.*, Kustini Lim-Wavde, Assessing carbon pollution standards: Electric power generation pathways and their water impacts, 120 Energy Policy 714-733 (2018), https://aquadoc.typepad.com/files/assessing_carbon_pollution_srandards_water.pdf.
[490] 42 U.S.C. § 7411(b)(2).

worse, and less protective, nationwide. Under section 111 "EPA must examine the effects of technology on the grand scale in order to decide which level of control is best."[491] EPA is not required to tailor new source performance standards to those few, isolated places where a BSER is not adequately demonstrated. EPA has not shown that water availability concerns are widespread or cannot be managed, but even if EPA did, it would be an abuse of discretion for EPA to choose to promulgate a nationwide standard that is significantly less consistent with the aims of the Clean Air Act, when it could subcategorize to address scenarios where water availability is of concern.

G. EPA's Rejection of Alternatives is Arbitrary

In addition to failing to provide a lawful and arbitrary rationale for discarding the current BSER, the Proposal's consideration of alternatives to the proposed system is inadequate and arbitrary. As noted above, EPA's obligation under section 111 to select the "best" system of emission reduction—as well as general principles of administrative law—necessarily require the agency to consider reasonable alternatives to its proposed approach, and provide sound and statutorily permissible reasons for rejecting those alternatives.[492] As explained below, EPA's cursory and flawed consideration of natural gas co-firing and other alternatives to its proposed BSER fails this standard.

i. EPA Fails to Give Due Consideration to Natural Gas Co-firing

1. Natural Gas Co-Firing Is a Technically Feasible and Cost-effective Way of Reducing Carbon Pollution for New Steam EGUs

As we have already explained in detail in comments we submitted on EPA's proposed replacement to the Clean Power Plan, co-firing with natural gas is an adequately demonstrated and cost-effective way of significantly reducing carbon pollution at coal-fired steam EGUs and can also yield significant reductions in co-pollutants.[493] EPA's rejection of a technique that is this meets the statutory requirements and achieves greater emission reductions than its proposed BSER is manifestly arbitrary.

The technology to co-fire with natural gas has been well-established for decades, and is commercially available and in widespread use. In fact, natural gas co-firing is currently used in existing steam EGUs for a variety of reasons, including for emissions control, to make up for the low energy content of Western coals, and to assist with startup as gas igniters heat up the furnace

[491] *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).
[492] *See, e.g., Del. Dep't of Nat. Res.*, 785 F.3d at 18 ("Because EPA too cavalierly sidestepped its responsibility to address reasonable alternatives, its action was not rational and must, therefore, be set aside.") (citations omitted); *Neighborhood TV Co.*, 742 F.2d at 639 (reviewing courts must "ensure that the agency 17 took a 'hard look' at all relevant issues and considered reasonable alternatives to its decided course of action") (citing *State Farm*, 463 U.S. at 41–43)); Mass. v. EPA, 549 U.S. 497, 532-533 (EPA's exercise of judgment "is not a roving license to ignore the statutory text. It is but a direction to exercise discretion within defined statutory limits.").
[493] Environmental Defense Fund, Comment Letter on Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations; Revisions to New Source Review Program, 83 Fed. Reg. 44,746, at 23 (Oct. 31, 2018) [hereinafter EDF ACE Comments].

to allow ignition of coal. Power companies have been converting coal-fired EGUs to burn natural gas as a primary fuel for over a decade. In its 2017 Reconsideration Denial, EPA reported 12 GW of capacity across 19 states that have switched their primary fuel from coal to natural gas.[494]

There is also no reason to believe that pipeline infrastructure limitations would preclude the use of increased natural gas co-firing to reduce emissions. A 2018 analysis by M.J. Bradley & Associates (MJB&A), which we included in the record for the proposed Clean Power Plan replacement, evaluated the availability of natural gas transportation in interstate pipelines and found significant potential for increased natural gas co-firing at existing coal-fired EGUs.[495] According to MJB&A, roughly 60% of the existing U.S. coal-fired fleet would be able to convert entirely to natural gas, and about 75% would be able to achieve some level of co-firing based solely on the *existing* interstate natural gas pipeline infrastructure and capacity.[496] MJB&A also found that nearly 60% of the existing coal-fired fleet would need less than 25 miles of lateral pipelines to transport natural gas from their nearest interstate pipeline flow points and at more than 50% of the existing coal-fired EGUs, only one lateral pipeline to the nearest interstate pipeline was needed.[497] Unlike existing EGUs, new EGUs have flexibility to locate next to a natural gas pipeline so this should not even be a concern.

In the 2015 Final Rule, EPA also found natural gas co-firing to be cost-reasonable for achieving carbon emission limitations.[498] Indeed, the fact that many conversion projects have recently been completed or are currently underway demonstrates that costs are reasonable.[499] According to a 2014 report by Andover, many power companies are undertaking coal-to-gas conversions because they sometimes represent the most economical option for complying with other emission limitations.[500] In its analysis of natural gas co-firing at existing coal-fired EGUs, MJB&A also estimates a conservative levelized cost of avoided carbon pollution from co-firing to be in the range of $67 to $72 per ton (nominal$) through 2035.[501]

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[494] EPA, BASIS FOR DENIAL OF PETITIONS TO RECONSIDER AND PETITIONS TO STAY THE CAA SECTION 111(D) EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS AND COMPLIANCE TIMES FOR ELECTRIC UTILITY GENERATION UNIT, app. 3, 19 (2017); *see also* EDF ACE Comments, *supra* note 493, at 24; *see also* Clean Air Task Force, Comment Letter on Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations; Revisions to New Source Review Program, 83 Fed. Reg. 44,746, at 45–46 tbl.BB (Oct. 31, 2018) (showing over 10 GW of coal capacity that exists in a variety of states, ownership structures, and regulatory regimes that has converted to natural gas or invested in co-firing capabilities); *see also* Nat. Res. Def. Council, Comments Letter on EPA's Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program, app. H (Oct. 31, 2018) (listing over 50 GW of U.S. coal units that currently co-fire with natural gas).
[495] M.J. BRADLEY & ASSOCIATES, PIPELINE ANALYSIS RESULTS (2018) [hereinafter MJB&A Analysis]; *see also* EDF ACE Comments, *supra* note 493, at 24–25.
[496] MJB&A Analysis at 11; EDF ACE Comments, *supra* note 493, at 25.
[497] MJB&A Analysis at 12; EDF ACE Comments, *supra* note 493, at 25.
[498] 2015 Final Rule, 80 Fed. Reg. at 64,545.
[499] Depending on the level of natural gas co-firing, co-firing is expected to be even cheaper than conversion.
[500] *See* EDF ACE Comments, *supra* note 493, at 28 (citing ANDOVER TECHNOLOGY PARTNERS, NATURAL GAS CONVERSION AND COFIRING FOR COAL-FIRED UTILITY BOILERS (2014).
[501] *Id.* (MJB&A's analysis accounts for the efficiency loss from the co-firing process as well as potential increases in natural gas prices due to the additional incremental natural gas demand from co-firing. MJB&A's analysis relies on "natural gas price projections from EIA's 2018 Annual Energy Outlook Reference Case. EIA's more recent 2019 Annual Energy Outlook projects even lower natural gas prices).

2. Just Because there are More Efficient Uses for Natural Gas Does Not Mean that Co-Firing Is Not BSER and there Is No Reason to Believe that it Would Preclude or Displace NGCC Generation

EPA argues in the proposed rule that natural gas co-firing cannot be the BSER because "it is an inefficient way to generate electricity compared to use of an NGCC" and "it would not be environmentally beneficial for utilities to combust natural gas in less [efficient] steam generating units to satisfy a facility specific emissions standard."[502] However, EPA does not explain how it has determined that co-firing is not the "best" use of natural gas. Further, as we discuss in detail in Section II.G.iii below, if EPA believes that NGCC best fulfills the "energy requirements" criterion for BSER, it should eliminate the coal-fired power subcategory of electric generating units and adopt that as BSER for all units.

As EDF already explained in detail in comments submitted on EPA's proposed replacement to the Clean Power Plan, co-firing with natural gas can provide significant environmental and health benefits relative to the ineffective BSER EPA has proposed here. Indeed, EPA's analysis for the proposed CPP showed that 50% natural gas co-firing at a utility boiler could reduce the CO_2 emission rate by 21% and switching to 100% natural gas could lower the emission rate by 42.8%.[503] EPA also estimated that converting to 100% natural gas would significantly reduce a coal steam EGU's emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and fine particulate matter ($PM_{2.5}$).[504] In fact, according to case studies by Andover Technology Partners, five coal-fired EGUs that have converted to natural gas show average emission rate reductions of 99% for SO_2 and 48% for NO_x.[505] These pollutants' serious health impacts are well documented. According to EPA, the value of the health benefits associated with these reductions are estimated to be between \$67/MWh-net and \$150/MWh-net—a factor of at least two times the cost associated with conversion.[506] Natural gas co-firing or conversion also has substantial non-air health and environmental benefits that EPA must consider in evaluating the BSER. For instance, coal-to-gas conversion eliminates production of coal combustion residuals or coal ash, an industrial waste that contains toxic substances such as arsenic, selenium, and cadmium. Conversion to natural gas also reduces on-site water quality impacts.[507]

EPA also argues that "a significant benefit of a new coal-fired power plant is the fuel diversity value that it brings" and "[r]equiring the EGU to burn natural gas defeats the purpose of

[502] Proposal, 83 Fed. Reg. at 65,445.
[503] *See* EDF ACE Comments, *supra* note 493, at 26.
[504] *Id.* at 27; *see also* EPA, GHG ABATEMENT MEASURES 6-6 tbl. 6-2 (2014) [hereinafter ABATEMENT MEASURES TSD] (EPA estimated that 100% natural gas conversion would reduce SO_2 emissions by 3.1 lb/MWh-net, NO_x by 2.04 lb/MWh-net, and $PM_{2.5}$ by 0.2 lb/MWh-net).
[505] *See* EDF ACE Comments, *supra* note 493 at 27, *see also* ANDOVER TECHNOLOGY PARTNERS, NATURAL GAS CONVERSION AND COFIRING FOR COAL-FIRED UTILITY BOILERS (2014).
[506] *See* EDF ACE Comments, *supra* note 493, at 27, *see also* ABATEMENT MEASURES TSD, *supra* note 504, at 6-7 tbl. 6-3 (even with a steep 7% discount rate, EPA estimated the health benefits of reducing co-pollutants through 100% natural gas conversion to be between \$61/MWh-net and \$140/MWh-net. EPA estimated the value of the health benefits associated with 10% natural gas co-firing to be between \$6.5/MWhnet and \$15/MWhnet).
[507] EDF ACE Comments, *supra* note 493, at 28.

constructing the EGU in the first place."[508] However, EPA fails to recognize that a coal-fired EGU with some degree of natural gas co-firing would still have fuel diversity benefits—and an EGU that is capable of combusting coal or natural gas would have very significant fuel diversity benefits as the value of fuel diversity is in the potential to combust an alternative fuel should another fuel experience price volatility or shortages, not in the combustion of the alternative fuel when such volatility or shortages are not occurring. In addition, the information we have provided above and the fact that many power companies have either converted their steam EGUs entirely to natural gas or undertake co-firing at some level cut against EPA's arguments.

There is also no reason to believe that natural gas co-firing at steam EGUs would preclude or displace the NGCC generation that EPA believes is the most efficient use of natural gas. In fact, this is directly contradicted by the MJB&A analysis we discussed above, which fully takes into account demand for natural gas from existing NGCC units. MJB&A's analysis further found that increased natural gas demand resulting from substantially increased co-firing at a large number of existing units would be well within current EIA forecasts for future natural gas demand growth, and would have minimal impacts on natural gas prices.[509] In light of the relatively small number of coal-fired EGUs expected to be built under the Proposal, the impacts of designating co-firing as the BSER on demand for NGCC generation and the natural gas market would be comparatively much smaller. There is simply no basis for EPA to suggest that natural gas supplies are so constrained that designating co-firing as the BSER would divert natural gas from NGCC or otherwise encourage inefficient use of natural gas.

3. EPA Concedes that Natural Gas Co-Firing Could Be Viable for Some Coal-fired EGUs Yet Fails To Consider Subcategorization

Even if EPA believes natural gas co-firing is not available everywhere, the Proposalconcedes that it could be viable for some coal-fired EGUs. Yet EPA fails to consider subcategorization of steam EGUs. For instance, EPA does not consider whether steam EGUs that are located closer to interstate natural gas pipelines, or to pipelines that have demonstrable spare capacity, would find it cost-effective and feasible to co-fire. In light of the inadequacies of EPA's proposed standards and the urgent need to achieve significant reductions in climate pollution from the power sector, EPA's failure to consider these more effective alternatives is arbitrary.

4. EPA's Reliance on the "Energy Requirements" Factor to Reject Co-firing as the BSER is Arbitrary

In rejecting co-firing as the BSER for new coal-fired power plants, EPA notes that, "[w]hile co-firing with natural gas in a utility steam generating unit a technically feasible option [*sic*] to reduce CO_2 emission rates, it is an inefficient way to generate electricity compared to use of an NGCC."[510] Thus, after an extended discussion of the technical potential for co-firing, the agency eventually concludes:

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[508] Proposal, 83 Fed. Reg. at 65,445.
[509] *See* EDF ACE Comments, *supra* note 493, at 31–32.
[510] Proposal, 83 Fed. Reg. at 65,445.

> Co-firing natural gas is an inefficient use of the nation's natural gas resources, which is relevant under the "energy requirements" criterion for BSER. Combined cycle EGUs are more efficient at using natural gas to generate electricity and it would not be environmentally beneficial for utilities to combust natural gas in less steam generating units [*sic*] to satisfy a facility specific emissions standard. [511]

The agency's rationale is flawed.

EPA cannot disregard a potential system of emission reduction based solely on a better business use of a fuel; it is not the agency's role under CAA section 111 to determine the most economically efficient use of raw materials. Many pollution reduction systems reduce the efficiency of the regulated sources—but their purpose—and EPA's purpose, under the Clean Air Act—is to reduce emissions, not maximize source efficiency. EPA could cite the fact that NGCC are both lower cost and lower emitting than coal-fired power plants and identify NGCC as the BSER for electric generating units. But it has not done so. Rather, EPA attempts to tie its conclusion—loosely—to the statutory factors of energy requirements and emission reductions. Although natural gas is used to supply NGCC units, and a more-efficient use of a fuel would generally decrease emissions and lower costs (assuming its supply is constrained), here EPA has not identified the more-efficient use of natural gas in producing electricity as the BSER. Instead, it has proposed to allow coal-fired EGUs to continue to be built and eliminated a viable, cost-effective system of emission reduction based on asserted concerns about fuel use efficiency. In doing so, the agency has arbitrarily misapplied the statutory factors that instruct EPA's selection of the best means of reducing emissions from the relevant source category. If EPA has concerns about the effects of a potential BSER on the environment and energy beyond the source category, it must substantiate those concerns with evidence, which it has not done here.

EPA's rationale for eliminating co-firing claims to base its BSER analysis in part on the environmentally optimal use of fuels—even though its selected system of emission reduction will not secure the allegedly "environmentally beneficial" fuel use. EPA cannot exclude a potential system of emission reduction based merely on its speculation that fuels will be diverted from cleaner production processes without putting in place a regulatory framework that will secure the use of cleaner production processes.

If EPA in fact believes that combusting natural gas in NGCC units better fulfills statutory purposes than co-firing, then it must include NGCC technology as one alternative in its BSER analysis. If it then concludes that NGCC technology outperforms other options under the statutory factors, it should eliminate the coal-fired EGU subcategory and identify NGCC technology as the BSER for all fossil fuel-fired EGUs. As noted below, EPA's 2012 proposal along these lines was lawful and well supported.

ii. EPA Fails to Give Due Consideration to Integrated Gasification Combined Cycle (IGCC)

In the Proposal, EPA asserts that while IGCC units are projected to have lower gross-output based emission rates compared to SCPC, "the design net emission rates and absolute

[511] *Id.*

amount of emissions to the atmosphere tend to be materially similar so there are limited, if any, net GHG benefits."[512]

In the Proposal, EPA also shows design net emission rates for IGCC at 1,730 lb/MWh-net, comparable to bituminous supercritical PC at 1,710 lb/MWh-net, lower than bituminous subcritical PC at 1,780 lb/MWh-net and lower than low rank supercritical or ultra-supercritical PC at 1,890 and 1,840 lb/MWh-net respectively.[513] The Proposal's estimated net emissions rate for IGCC is also significantly lower than the standards EPA has proposed, the lowest of which is 1,900 lb/MWh on a gross basis (and imposes no limit at all with respect to net generation).[514] Thus, even when considering net emission rates, IGCC technology would offer significant GHG reductions relative to the standards EPA has proposed. EPA's rejection of IGCC as an alternative BSER is therefore arbitrary and unjustified.

iii. EPA Fails to Consider NGCC as the BSER

EPA also entirely fails to consider an alternative that the agency considered in April 2012 when it first proposed carbon pollution standards for new EGUs: the option of eliminating the coal-fired EGU subcategory and identifying NGCC technology as the BSER for all fossil fuel-fired EGUs. This option is consistent with section 111 and with prior NSPS that have established standards based on clean and newly dominant production processes that have displaced older and less-efficient processes.[515] It is also supported by facts EPA recognizes in the Proposal—including the lack of current plans for new coal-fired EGU construction, and the increasing dominance of natural gas in baseload power generation and in the provision of other energy services formerly provided by coal-fired EGUs.

EPA's 2012 proposal along these lines was lawful and well supported. The agency correctly noted that "[n]atural gas combustion inherently emits less CO_2 than coal combustion and the technology of choice for generating electricity with natural gas, stationary combined cycle gas turbines, is also more efficient."[516] EPA observed that it need not promulgate standards of performance for types of sources that are unlikely to be built, and that standards "may legitimately reflect less polluting types of designs and discourage perpetuation of more polluting designs."[517]

EPA has recognized that section 111 defines BSER broadly to allow for systems beyond just emission control hardware. As early as 1976 EPA stated that:

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[512] *Id.* at 65,447.
[513] *Id.* at 65,447 (indicated in table 9, Cost and Emission Rates of Coal-Fired EGUs (2016$), based on NETL baseline fossil reports).
[514] *Id.* at 65,427.
[515] *Portland Cement Ass'n v. EPA (Portland Cement III)*, 665 F.3d 177, 190 (D.C. Cir. 2011) (EPA properly based the NSPS for new cement kilns on a recent and more efficient production process, even though many older kilns still existed that did not utilize the same technology).
[516] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392, 22,396 (proposed Apr. 13, 2012) [2012 Proposed Rule]; *see also id.* at 22,418 ("[I]t seems unlikely that utilities would choose a natural gas-fired boiler as the generation technology of choice when NGCC is a much more efficient, less expensive, and more widely used technology.").
[517] RESPONSE TO COMMENTS ON 2014 PROPOSED RULE, *supra* note 88, at 2-81 (Response 2.1-210) (paraphrasing *Portland Cement III*, 665 F.3d at 190).

> For some classes of sources, the different processes used in the production activity significantly affect the emission levels of the source and/or the technology that can be applied to control the source. For this reason, the Agency believes the 'best system of emission reduction' includes the processes utilized and does not refer only to emission control hardware. It is clear that adherence to existing process utilization could serve to undermine the purpose of section 111 to require maximum feasible control of new sources.[518]

The 1970 "best system of emission reduction" language that the agency interpreted is identical to the current language, reinstated in 1990.[519]

The legislative history of Section 111 further demonstrates that Congress intended for consideration of cleaner fuels and combustion methods as the BSER. The 1990 amendments revised the NSPS to eliminate the requirements that the NSPS be based on a "technological" system of emission reduction and that combustion emissions from "fossil fuel fired stationary sources" be reduced by a set percentage. As the House Committee Report stated, this had the effect of "giv[ing] units the flexibility to meet the emission rates established under the new standards through whatever combination of fuels and emission controls the units choose."[520] This is clearly consistent with a proposal to establish a standard of performance that can be met by using on the best available clean burning fossil fuels and more efficient combustion methods, such as efficient combined cycle natural gas turbines. In the 2012 proposal, the agency therefore acted well within its authority in proposing NGCC technology as the BSER for fossil fuel-fired EGUs.

Furthermore, in the 2012 proposal, EPA properly proposed to define the source category so as to maximize social benefits.[521] Given the absence of any explicit criteria to guide its categorization decisions, it was appropriate for EPA to consider factors similar to those informing the BSER analysis, enumerated in section 111(a)(1).[522] And, this would respond to EPA's own assertion in the present proposal it weakly offers to reject co-firing as an

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518 *See* Standards of Performance for New Stationary Sources: Primary Copper, Zinc, and Lead Smelters, 41 Fed. Reg. 2332, 2333 (1976).

519 *Compare* CAA Amendments of 1970, PL 91-604, § 111(a)(1), 84 Stat. 1676, 1683 (1970) ("The term 'standard of performance' means 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) the Administrator determines has been adequately demonstrated."), *with* CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1) (2006) ("The term 'standard of performance' means 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.").

520 H.R. REP. NO. 101-490, pt. 1 (1990) (emphasis added).

521 *See* 2012 Proposed Rule, 77 Fed. Reg. at 22,411.

522 *See id.* ("[R]etaining separate source categories would be unlikely to generate substantial private cost savings, but at the same time, would create the risk of significantly higher GHG emissions and other air pollutants from some new units, resulting, in turn, in higher social costs.").

alternative.[523] EPA's argument that natural gas would be "more efficient[ly]"[524] used in NGCC units than in coal-fired EGUs itself demonstrates that both types of sources serve the same function—generating baseload electricity—and should be consolidated in one category when doing so would further the purposes of section 111. Changes in the energy sector since EPA's 2012 proposal only further strengthen the case for NGCC as being BSER across fossil-fuel fired EGUs. As EPA notes, natural gas has already been displacing coal-fired power due to its cost-competitiveness and EPA expects very few new coal plants to be constructed.[525] And, to the extent market conditions change in such a way as to favor construction of some coal-fired EGUs, CCS remains a compliance option that coal-fired EGUs can use to meet a standard based on NGCC as the BSER—as EPA explicitly recognized in the 2012 proposal.

EPA must provide a neutral, consistent, data-driven analysis of adequately demonstrated systems of emission reduction according to the statutory factors—emission reductions, cost, impacts on energy, and impacts on other pollution problems. The agency has not tied its decision to revise the 2015 Final Rule to these statutory factors, which would support the selection of partial or full CCS as the BSER for coal-fired EGUs or NGCC technology as the BSER for the category of coal- and natural gas-fired EGUs. We urge EPA to abandon this proposal as insufficiently supported by the technical and statutory analysis and evaluate a strengthening of the current standards based on a reassessment of the availability and cost-effectiveness of CCS technologies and of the potential for NGCC to serve as BSER for fossil fuel-fired EGUs.

H. EPA's Proposed Standards Do Not Reflect the Degree of Reduction "Achievable" Using the Most Efficient Demonstrated Steam Cycle and Best Operating Practices

In addition to providing manifestly arbitrary and unlawful rationales for discarding the current BSER in favor of a far less effective system of emission reduction, the actual standards proposed by EPA lag hopelessly behind what is achievable by modern coal-fired generating units utilizing efficient steam cycles and operating practices. EPA's proposed standards are therefore arbitrary and unlawful. EPA is proposing that the BSER for newly constructed fossil steam EGUs would be the most efficient demonstrated steam cycle (supercritical steam conditions for large EGUs and best available subcritical steam conditions for small EGUs) in combination with the best operating practices. Based on that, EPA is proposing the following emission standards:

- 1,900 lb CO_2/MWh-gross for large EGUs (heat input >2,000 MMBtu/h)
- 2,000 lb CO_2/MWh-gross for small EGUs (heat input <=2,000 MMBtu/h)
- 2,200 lb CO_2/MWh-gross for coal refuse-fired EGUs[526]

As evidenced from a new report by Andover Technology Partners, even without considering partial CCS or other alternatives, EPA's proposed standards do not reflect the degree of reduction that is achievable.[527] Andover examines CO_2 emission rates for new, uncontrolled

[523] Proposal 83 Fed. Reg. at 65,445.
[524] *Id.*
[525] *Id.* at 65,427.
[526] *Id.* (indicated in Table 1).
[527] ANDOVER TECHNOLOGY PARTNERS, NEW SOURCE PERFORMANCE STANDARDS FOR COAL STEAM EGUS (2019).

(no CO_2 capture) coal EGUs using information on coal technologies and data on coal units currently in operation and concludes that EPA's NSPS emission rates are far too weak and can be substantially improved.[528] According to Andover, EPA's proposed standards are achievable with subcritical steam technology that has been available for over 50 years.[529] Indeed, EPA's own analysis shows that for bituminous and subbituminous fuels the NSPS limits are readily achievable with subcritical steam conditions at a 99.5% confidence rate.[530] In fact, EPA's own assessment of partial CCS is based off SCPC emission rates that are lower than EPA's own proposed standards.[531]

i. EPA's Proposed Standards are Based on Extremely Rare Plant Characteristics that are Not Found in Combination Anywhere in the U.S.

EPA improperly identifies a combination of plant characteristics that are individually rare—with no record evidence that such conditions do or will ever exist in combination—and then uses this nonexistent unknown combination to determine the proposed NSPS rate. As a result, the proposed NSPS rate is barely better than the fleet rate in the United States. Yet again, EPA uses an unreasonable, unjustified worst case scenario to rationalize extremely weak and unprotective standards.

EPA's proposed standards are determined based on the combination of two extremely rare techniques—dry cooling and dried lignite fuel—that have never been used together in the U.S. [532] The vast majority of existing coal facilities in the U.S. use bituminous or subbituminous fuel and recirculation cooling. When assessing a new technology, courts have not required EPA to show the successful application to all possible configurations or combinations of boilers and coal types.[533] It is sufficient for EPA to show the technology can be applied across a range of likely conditions.[534]

Andover reports that there were only 14 lignite units out of 495 coal-fired EGUs listed in EIA's Form 860 in 2017.[535] There were only three pulverized coal EGUs with dry cooling – all located in Gillette, WY—and one coal-refuse unit with dry cooling in Virginia.[536] For each of these units, the location was determined by the location of the fuel. According to Andover, "[t]here are no facilities, and there likely will never be any facilities, that are both lignite-fired and have dry cooling."[537] Lignite has unique qualities that include extremely low heating value, geographic limitations, and severe heat rate penalties. It is therefore unreasonable to use it as a basis for a nationwide standard. Dry cooling is even less common and all three pulverized coal

[528] *See id.* at 1.
[529] *Id.*
[530] *Id.*
[531] *See, e.g.*, Proposal, 83 Fed. Reg. at 65,436–37 tbl.4; NSPS ECONOMIC IMPACT ANALYSIS, *supra* note 10, at 2-4 tbl. 2-1.
[532] Proposal, 83 Fed. Reg. at 65,451.
[533] *Lignite Energy Council*, 198 F.3d at 934 n.3 ("In assessing a new technology like SCR, EPA is not required to provide evidence of its application to boilers burning every type of coal from every geographical location.").
[534] *Id.* at 934.
[535] ANDOVER 2019 REPORT, *supra* note 4, at 2.
[536] *Id.*
[537] *Id.*

units with dry cooling are located within a four-mile radius next to PRB coal mines in a remote and arid region.[538]

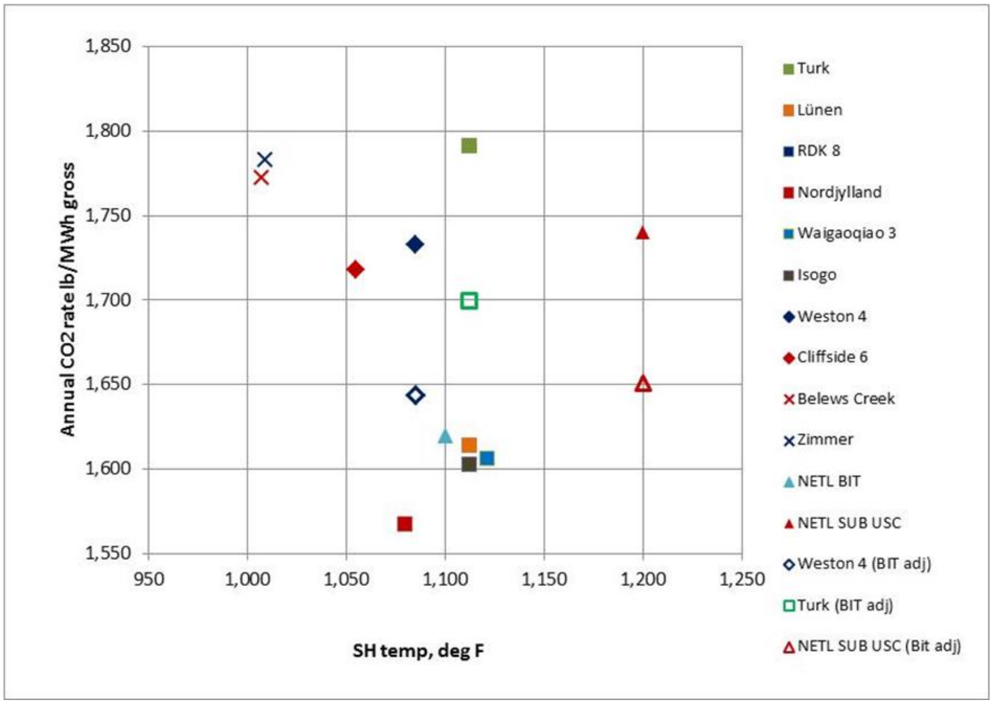
Andover concludes that "[b]y having these rare conditions—and more importantly, a *combination* of these rare conditions—determine the NSPS rate, EPA has created an NSPS rate that is barely better than the fleet rate in the United States—a fleet that is 60% subcritical—and falls short of the average *fleet* rates in the European Union, China and particularly Japan."[539] Accordingly, EPA's proposed rates do not reflect the "maximum practicable degree" of emission reduction from new sources or the "degree of reduction achievable" using EPA's proposed BSER, as section 111 requires.[540] Further, these standards are arbitrary because they run "counter to the evidence before the agency" and demonstrate no "rational connection between the facts found and the choice made."[541] EPA cannot base the NSPS on a combination of extraordinary circumstances that EPA never demonstrates might actually exist.

ii. EPA's Proposed Standard for Large Coal EGUs Does Not Reflect Use of Readily Available, Modern Supercritical and Ultrasupercritical Technology

EPA's proposed standard for large coal EGUs is 1,900 lb/MWh-gross. According to EPA, the proposed standard is based on the use of ultrasupercritical (USC) or supercritical (SC) steam generation technology.[542] Yet according to Andover, and as shown in Figure 7, an assessment of USC and SC coal units in both the United States and abroad demonstrates that emission rates associated with these units are well below EPA's proposed standard.[543] In fact, EPA's own analysis when normalizing the Weston 4 coal unit for purposes of proposing the new standard shows that an advanced ultra-supercritical unit with bituminous coal and wet cooling can achieve a 1,550 lb/MWh-gross rate with 99% confidence.[544]

[538] *Id.*
[539] *Id.*
[540] *Essex Chemical Corp.*, 486 F.2d at 437.
[541] *State Farm*, 463 U.S. at 43.
[542] Proposal, 83 Fed. Reg. 65,430–31.
[543] ANDOVER 2019 REPORT, *supra* note 4, at 6-10.
[544] *See* Memorandum from EPA on Best System of Emissions Reduction (BSER) for Steam Generating Units and Integrated Gasification Combined Cycle (IGCC) Facilities, at 11 fig. 9-1 (Dec. 2018).

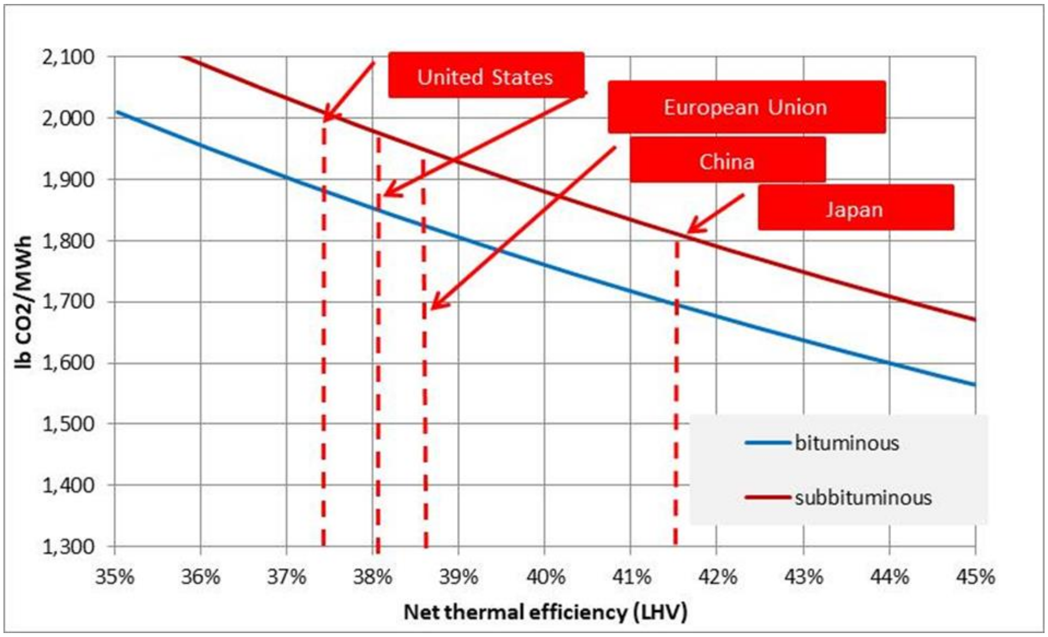
Figure 7: Annual CO_2 Emission Rates of USC and SC Coal EGUs[545]



Andover also shows that the average existing coal fleet efficiency in the U.S. is much lower compared to other nations—due in part to the U.S. lagging behind other nations in deployment of USC technology.[546] According to Andover, as of March 2016, over 60% of the U.S. capacity was subcritical.[547] Accordingly, and as shown in Figure 8, the existing U.S. fleet has emission rates around 1,900 to 2,000 lb/MWh-gross. By comparison, the average existing fleet emission rate in Japan is only about 1,700 lb/MWh-gross due to predominantly USC and SC technology and bituminous coal.[548] There is no reason to believe a new coal unit would not be capable of deploying USC or SC technology together with the highest coal rank or fuel type. Therefore, EPA's proposed standard for large coal EGUs is far too weak to satisfy the section 111 requirement that it reflect the "degree of emission limitation achievable" using EPA's proposed BSER.[549]

545 ANDOVER 2019 REPORT, *supra* note 4, at 8 (U.S. units calculated from EPA Air Markets Program Data – average of 2014 and 2015 annual rate. For overseas units, rate is estimated from reported efficiency data and assumed coal CO_2 emission rate).
546 *Id.* at 8–9.
547 *Id.* at 8.
548 *Id.* at 9.
549 42 U.S.C. § 7411(a).

Figure 8: CO_2 Emission Rate vs. Efficiency for Different Fuels[550]



EPA states that establishing supercritical technology as the basis for control requirements in the U.S. would help establish it in other nations and that the proposed BSER would promote the development and implementation of viable control technologies that is readily transferrable to other countries.[551] However, promotion of technology internationally was not one of Congress's aims with section 111. Further, according to Andover's analysis, EPA's proposed NSPS for large coal EGUs "is only modestly better than what the US fleet currently achieves on average, is less stringent that the average in China and is well short of what is average for Japan. Therefore, other nations are a model for the United States, and EPA's proposed NSPS will not be a model for other nations."[552] EPA is permitted to take under consideration methods of emission reduction that have been successfully demonstrated in foreign countries.[553]

iii. EPA's Proposed Standard for Small Coal EGUs Fails to Recognize that there is No Technical Reason Why a Small Boiler Cannot Use Supercritical Technology

The existing fleet of small coal EGUs in the U.S. is very old and not representative of what could be deployed in a new unit. Indeed, small coal EGUs have a median operation date of 1961—compared to 1977 for large coal EGUs.[554] Small coal EGUs also tend to be uneconomical except in unusual situations, which would explain why so few of these units have been built in recent years. Andover reports that since 2000, only three coal EGUs between 25-200 MW (representative of what would be considered a small EGU) came online compared to 22 units

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550 *Id*.
551 *See* Proposal, 83 Fed. Reg. at 65,448.
552 ANDOVER 2019 REPORT, *supra* note 4, at 9.
553 *Lignite Energy Council*, 198 F.3d at 934 n.3.
554 ANDOVER 2019 REPORT, *supra* note 4, at 11.

greater than 200 MW that came online during that same time.[555] Of the three small EGUs, two are located next to low cost PRB coal mines and one is a cogeneration unit—hence efficiency was not a concern for these units which would explain the use of subcritical instead of supercritical conditions.[556]

Although EPA bases its standard for small coal EGUs on subcritical boiler operation, there is no technical reason why supercritical conditions cannot be achieved in a small boiler and EPA does not provide any record evidence to the contrary. Although small boilers may be less efficient compared to large boilers, they can be built to be supercritical and meet much lower emission rates than the 2,000 lb/MWh-gross standard proposed by EPA.[557] In fact, according to Andover, the first supercritical steam boiler was built in 1957 with a capacity of 120 MW.[558] Further, according to Andover, the difference in cost between subcritical and supercritical conditions is modest and there is no reason to believe it would be much different for small coal EGUs compared to large EGUs.[559] Accordingly, EPA's proposed standard for small coal EGUs cannot be reconciled with the record before the agency.

iv. EPA's Proposed Standard for Coal Refuse-fired EGUs is Not Justified

EPA's proposed coal refuse standard provides no adequate justification for subcategorization, and does not reflect the full degree of emission limitation achievable for this type of EGU. According to Andover, waste fuel boilers are universally Circulating Fluidized Bed (CFB) fired.[560] EPA's proposed standard fails to recognize that CFB is the typical combustion technology for coal refuse.[561] EPA also did not use available data on CFB-fired coal boilers or waste fuel boilers when determining the coal refuse-fired EGU standard.

Andover examined CFB and coal refuse data and found that coal refuse boilers are expected to emit roughly 10% more than bituminous fuel boilers for any given efficiency.[562] Based on Andover's analysis, emission rates for CFB EGUs at 99% confidence level are well below EPA's proposed standard. Even after adjusting for the higher emission rate per unit of heat input from coal refuse, emission rates are still lower than EPA's proposed rate of 2,200 lb/MWh-gross.[563] Further, according to Andover, although CFB boilers are mostly subcritical, supercritical CFB boilers are being built internationally in areas where there is greater demand for coal boilers that burn low quality fuels.[564] Accordingly, emission rates reflecting achievable efficiencies for supercritical CFB EGUs would be even lower than the data on U.S. CFB EGUs would indicate. To the extent a separate standard for coal refuse units is considered, it should be based on supercritical CFB.

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[555] *Id.* (a 2,000 MMBtu/h steam generator has a capacity of roughly 200 MW).
[556] *Id.* at 11–12.
[557] *Id.* at 2, 11.
[558] *Id.* at 11.
[559] *Id.*
[560] *Id.* at 2.
[561] *Id.* at 12–13.
[562] *Id.*
[563] *Id.*
[564] *Id.*

In addition to failing to provide adequate support for this proposed standard, the Proposal provides no compelling justification for creating this subcategory in the first place. Coal refuse-fired EGUs are emission-intensive and there is no reason for a national standard that is intended to drive reductions to the maximum feasible degree to make special accommodations to enable or encourage this type of EGU. As such, EPA should not finalize a separate standard specifically for coal refuse-fired EGUs.

v. EPA's Adjustments to Emission Rates Are Arbitrary and Artificially Inflate Emission Rates

When determining the proposed standards, EPA uses a number of conditions to adjust or normalize emission rates. Not only are these adjustments not justified but EPA also fails to provide details of how adjustment factors were developed. According to Andover, by normalizing emission rates, EPA artificially inflates the NSPS rate to well above what is achievable for the vast majority of coal-fired boilers.[565]

As previously discussed, EPA's proposed NSPS is based upon a combination of dry cooling and lignite. However, no such plant exists or will likely exist—each of these individually is extremely rare and in combination do not exist. EPA does not provide any information to the contrary. Therefore, EPA's proposed NSPS is based on an unrealistic set of assumptions that artificially inflate the proposed rate.[566]

EPA also proposes to normalize for capacity factor. However, coal-fired EGUs have much higher capital costs than natural gas-fired EGUs and new coal EGUs will therefore only be developed in situations where high capacity factors are expected.[567] In fact, according to Andover, EPA's own analysis of hourly emission data and operating time versus capacity factors demonstrates that coal EGUs tend to operate primarily at capacity factors associated with the lowest emission rate.[568]

vi. EPA's Analysis Contains Errors That Further Inflate Emission Rates

Andover notes errors in EPA's analysis that only inflate emission rates. For instance, when determining the 99% confidence level emission rate, EPA takes the average emission rate and adds the standard deviation multiplied by 2.57.[569] However, according to Andover that is incorrect since this would be representative of a 99.5% confidence limit.[570] To determine an NSPS limit at 99% confidence level, the standard deviation should instead be multiplied by 2.33—which would have the effect of lowering emission rates.[571] Another apparent error noted by Andover involves using Weston 4 instead of Cliffside 6 as the lowest emitter for large coal EGUs.[572] Weston 4 had a similar average annual emission rate but a higher standard deviation,

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[565] *Id.* at 14.
[566] *Id.* at 16.
[567] *Id.* at 17.
[568] *Id.*
[569] *Id.* at 5.
[570] *Id.*
[571] *Id.* at 5–6.
[572] *Id.* at 6.

which means that a lower emission rate is justified than what EPA proposed for large coal EGUs.[573]

I. To the Extent EPA Based the BSER on Concerns About "Onsite Fuel Storage," it is Arbitrary and Unlawful.

In both the preamble to the proposed rule and the economic impact analysis, EPA makes reference to potential "federal policy intervention, including mechanisms to incorporate value for onsite fuel storage" as an uncertainty in its analysis that few new coal-fired EGU units will be developed.[574] This appears to make reference to the Grid Resiliency Pricing Rule proposed by the Department of Energy for final action by the Federal Energy Regulatory Commission (FERC) under Section 403 of the Department of Energy Organization Act.[575] The proposal would guarantee additional profits to owners of nuclear and coal power plants under the misguided, deceptive rationale that doing so would promote grid resiliency and reliability.

EDF joined a group of NGOs in submitting comments opposing the proposal and explaining how onsite fuel storage is unrelated to grid reliability.[576] As the comments note, a report issued by DOE itself found that changes to the grid and retirements of coal plants posed no threat to grid resiliency.[577] Evidence shows that retirements of nuclear and coal-fired power plants pose no threat to reliability because the ability to store fuel onsite bears no correlation to the reliability or resiliency of the power source. This was the conclusion drawn by a Rhodium Group analysis based on power disruption data from the last five years.[578] It found that only 0.00007% of outages resulted from fuel supply problems and that "…increasing amounts of coal and nuclear generation on a utility's system has no relationship with improved reliability metrics."[579] FERC unanimously denied the proposal, finding that there was no evidence that coal or nuclear retirements harmed grid resilience and that the proposal would discriminate in favor of nuclear and coal despite the fact that other resources may have resilience attributes.[580] Another report determined, "the vast majority of outage events arise at the distribution and transmission

[573] *Id.*
[574] EIA at ES-3; EIA at 2-1; EIA at 3-1; Proposal, 83 Fed. Reg. at 65,455; Proposal, 83 Fed. Reg. at 65,427.
[575] Department of Energy, Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (Oct. 10, 2017).
[576] Comments of Public Interest Organizations, Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Earthjustice, Sustainable FERC Project, Union of Concerned Scientists, The Center for Biological Diversity, The Environmental Law & Policy Center, The Southern Environmental Law Center, Conservation Law Foundation, Environmental Working Group, and Fresh Energy, Docket No. RM18-1-000, http://blogs.edf.org/energyexchange/files/2017/10/DOE-Comments-Final.pdf.
[577] DOE, Staff Report on Electricity Markets and Reliability (Aug. 2017), at https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.
[578] Rhodium Group, "Electric System Reliability: No Clear Link to Coal and Nuclear," October 23, 2017, https://rhg.com/research/electric-system-reliability-no-clear-link-to-coal-and-nuclear/.
[579] *Id.*
[580] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 F.E.R.C. ¶ 61,012 at 9-10 (Jan. 8, 2018).

levels from weather events"[581] and the best way to improve grid resilience is to target "the provision, operation and maintenance of distribution and transmission assets."[582]

Thus, as our comments stated, that Grid Resiliency Pricing Rule proposal was "a transparent attempt to reward a political ally through a generous and perpetual bailout. Lacking any semblance of support in record evidence or in any defensible analysis of the energy markets and the law the governs them, the Proposal can only be understood as an effort to prop up the coal industry in service of the Administration's political pledge to revive it."[583] EPA's reference to this policy in the preamble only further underscores this Administration's duplicitous attempt to claim that because the existing fleet of coal-fired power plants is decreasing and few new plants are expected, EPA regulation is not necessary to control pollution from these plants, while simultaneously making a series of attempts to counteract these trends and help sustain and promote the coal industry.

Bailing out or supporting the coal industry is not EPA's mission and should play no role in selecting the BSER for this proposal. EPA has a mission to protect human health and the environment. While the statute requires EPA to consider costs when selecting the BSER, this does not authorize EPA to select a less protective BSER specifically to prop up any particular industry. Thus to the extent that its rationale does not reflect real-world energy requirements or circumstances related to any other statutory factor, it is arbitrary for EPA to take under consideration "onsite fuel storage" when selecting the BSER.

III. EPA'S Economic Impact Analysis Unlawfully Fails to Analyze the Full Costs of its Proposed Standard

EPA's Proposal unlawfully fails to adequately consider the potential costs and benefits of its revised BSER determination. Specifically, the Proposal's economic impact analysis fails to evaluate properly the impact of its revised determination from the perspective of individual units. This failure stands in stark contrast with the approach taken by the Agency in the regulatory impact analysis (RIA) for the 2015 Final Rule—described below in detail—where EPA provided a thorough, unit-level analysis of the costs and benefits of the pollution reductions expected from compliance with the standards.

Recognizing that "an operator may find it desirable to construct a new coal-fired EGU,"[584] the Proposal includes a unit-level analysis. However, the analysis fails to include an appropriate range of alternatives for comparison. In addition, the Proposal's economic impact analysis monetizes the benefits to EGU owners and operators of EPA's proposed weakening of

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[581] Alison Silverstein, Rob Gramlich, Michael Goggin, A Customer-focused Framework for Electric System Resilience at 4 (May 2018), https://gridprogress.files.wordpress.com/2018/05/customer-focused-resilience-final-050118.pdf.
[582] *Id.* at 6.
[583] Comments of Public Interest Organizations, Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Earthjustice, Sustainable FERC Project, Union of Concerned Scientists, The Center for Biological Diversity, The Environmental Law & Policy Center, The Southern Environmental Law Center, Conservation Law Foundation, Environmental Working Group, and Fresh Energy, Docket No. RM18-1-000, at 5 http://blogs.edf.org/energyexchange/files/2017/10/DOE-Comments-Final.pdf
[584] NSPS Economic Impact Analysis, *supra* note 10 at 2-2.

the 2015 Final Rule revised determination for individual units but EPA performs no such monetization of the societal costs associated with the increased pollution the agency expects will result from its revised determination. This uneven, myopic approach is unlawful. EPA cannot place its "thumb on the scale by inflating the benefits of the action while minimizing its impacts."[585] "[I]f an agency elects to quantify the benefits of a proposed action, it must also quantify the costs,"[586] especially when the tools for doing so are readily available.[587]

EPA's failure to undertake a fair and balanced assessment of the costs and benefits of its Proposal at the unit level renders this EIA flawed and incomplete. Any reliance on this analysis to justify finalizing the Proposal would constitute arbitrary and capricious decisionmaking.

A. EPA's 2015 RIA Provided a Robust Analysis of the Impact of the 2015 Final Rule on Individual Investment Decisions, Including Monetization of Changes in CO_2, SO_2, and NO_x Pollution.

EPA's 2015 RIA presented a thorough analysis exploring the costs and benefits of the final standards for individual investment decisions.[588] The agency began its unit-level analysis by comparing the typical emissions profile of a new, non-compliant coal-fired unit[589] with that of various generation technologies in compliance with their respective standards, including an SCPC unit using CCS, an SCPC unit co-firing natural gas, and an NGCC unit. EPA's analysis showed that, relative to a non-compliant SCPC unit, an SCPC unit using partial CCS and meeting the 1,400 lb CO_2/MWh-gross standard would decrease CO_2 emissions by roughly 400,000 tons per year, and would also decrease SO_2 emissions by about 20 percent.[590]

Next, the RIA compared the health and climate impacts from these various generation technologies based on the differentials derived in the emissions comparison. Importantly, the agency monetized the impact of reductions in CO_2 and $PM_{2.5}$ that result from compliance with a standard reflecting partial CCS, facilitating comparison of air-pollution benefits and net benefits

[585] *Montana Environmental Information Center v. U.S. Office of Surface Mining*, 274 F. Supp. 3d 1074, 1098 (D. Mont. 2017); *see also Center for Biological Diversity v. National Highway Transportation Safety Administration*, 538 F.3d 1172, 1198 (9th Cir. 2008) ("[Agency] cannot put a thumb on the scale by undervaluing the benefits and overvaluing the costs of more stringent standards.").
[586] *WildEarth Guardians v. Zinke*, Nos. CV 17-80-BLG-SPW-TJC at 29 (Feb. 11, 2019); *see also* OMB Circular A-4 at 2 (Sept. 17, 2003) ("A good regulatory analysis should include . . . an evaluation of the benefits and costs—quantitative and qualitative—of the proposed action . . . .").
[587] *See Center for Biological Diversity v. NHTSA*, 538 F.3d at 1200 (holding agency's failure to monetize benefits of carbon emission reductions arbitrary and capricious because "it is possible to monetize the benefit").
[588] *See* Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, EPA-452/R-15-005, at 5-1 (Aug. 2015) [hereinafter 2015 RIA] ("[T]his chapter presents the results of several illustrative analyses that show, under a range of alternative conditions, the potential costs and benefits of these standards for individual investments that provide base load dispatchable generation.").
[589] The analysis considers both a non-compliant SCPC unit and a non-compliant IGCC unit, and assumes these are baseload units in compliance with current utility regulations (*e.g.*, MATS), operating at 85% capacity, and "using bituminous coal with a sulfur content of 2.8 percent dry. *See id.* at 5-2.
[590] *See* 2015 RIA at 5-4 (Table 5-1). The analysis likewise showed that the "typical new NGCC unit would emit about 1.9 fewer million [sic] tons of CO2 per year than the typical new SCPC unit, as well as roughly 1,700 fewer tons of SO2 and about 1,300 fewer tons of NOx per year than the SCPC unit." *Id.* at 5-2.

at individual plants.[591] Among other findings, the analysis concluded that the "incremental benefits associated with generation from a representative new [compliant] SCPC coal-fired unit with CCS relative to a new [non-compliant] SCPC unit without CCS are $3.1 to $18 per MWh (2011$)."[592] The agency's calculation included a detailed breakdown of the monetized incremental benefits of the constituent CO_2 and $PM_{2.5}$ reductions from compliance at various discount rates.[593]

EPA then conducted several illustrative analyses to assess the regulation's impact on net benefits under a range of scenarios.[594] In one part of the analysis, the agency compared the LCOE of a non-compliant coal unit to a compliant coal unit using partial CCS under three different scenarios. One scenario assumed that carbon captured by the compliant unit would not be sold for EOR.[595] The second and third scenarios assumed that the captured carbon would be sold for EOR, at $18 and $36 per ton, respectively.[596] Without EOR revenue (first scenario), EPA estimated the net monetized benefits to be between -$13 and $0.84 per MWh.[597] With EOR revenue (second and third scenarios), EPA estimated net monetized benefits of -$9.3 to $7.9 per MWh.[598] In another part of the analysis, EPA compared the LCOE of a non-compliant coal unit to a compliant NGCC unit across a range of assumptions about future natural gas prices.[599] That analysis began by noting that "[t]he estimated LCOE for a representative NGCC unit is roughly $34 and $43 per MWh less than for a representative new coal-fired SCPC," and concluded that "there would likely be a net social benefit, even under scenarios with higher than expected gas prices, if new compliant NGCC units were built in place of new non-compliant coal-fired units as a result of this rule."[600]

Taken as a whole, the unit-level analysis conducted in the 2015 RIA provided an important granular look at the costs and benefits associated with the final standard. Given the larger trend informing EPA's expectation that there would be no construction of new coal-fired generation capacity during the analysis period,[601] the unit-level assessment provided critical insight into the economics of any isolated instance where an individual operator might decide to construct new coal-fired generation. Thus, this breakdown facilitated a full understanding of the net benefits of compliance, across a range of scenarios, by monetizing the decrease in pollution resulting from application of the standard to a coal-fired power plant.

Importantly, the 2015 RIA monetized the benefits associated with reductions in CO_2, SO_2, and NO_x. According to EPA, "[t]he [social cost of carbon] estimates used in [the RIA] were developed over many years, using the best science available . . . ."[602] In particular, EPA used the latest Interagency Working Group (IWG) social cost of carbon (SCC) estimates to monetize the

[591] *Id.* at 5-7 (Table 5-2), 5-9 (Table 5-3).
[592] *Id.* at 5-8.
[593] *Id.* at 5-9 (Table 5-3).
[594] *Id.* at 5-12.
[595] *See id.* at 5-20 (Figure 5-1). EPA's sale price assumptions for CO2-EOR were based on assumptions used by NETL to evaluate EOR. *Id.* at 5-18, 5-19.
[596] *Id.* at 5-18, 5-19.
[597] *Id.* at 5-21 (Table 5-5).
[598] *Id.*
[599] *Id.* at 5-11.
[600] *Id.* at 5-12, 5-13.
[601] *See* 2015 RIA at 4-3, 5-16.
[602] *Id.* at 3-3.

value of impacts stemming from marginal changes in CO_2 emissions.[603] These Interagency Working Group estimates were developed through a multi-agency process that involved repeated rounds of review and public comment.[604] Though widely considered conservative, they are the best tool the agency has to monetize these benefits.

EPA also stated that its SCC estimates "represent[ed] global measures because of the distinctive nature of the climate change . . . ."[605] Specifically, EPA noted that GHG pollution causes global damage regardless of the location of the source; that the true costs of climate change to the United States are not adequately captured by direct impacts within U.S. borders given the global, interconnected nature of the economy in which the U.S. operates; and that achieving an economically efficient level of emissions reductions requires consideration of global benefits given that "climate change represents a classic public goods problem."[606] After "consider[ing] feedback on the [social cost of carbon] estimates from stakeholders through a range of channels," EPA selected SCC estimates of $13, $41, $62, and $120 per ton of CO_2 emissions.[607]

B. EPA's 2018 EIA Unlawfully Fails to Monetize Increased Pollution from the Proposed Standard.

EPA's Economic Impact Analysis (EIA) for the proposed rule likewise contains a chapter focusing on potential societal impacts of compliance by an individual unit. The analysis within this chapter, however, is deficient in several significant respects.

First, EPA fails to monetize the additional carbon pollution that would be emitted by a new coal unit under the proposed standard. The EIA compares SCPC units using partial CCS to achieve 1,400 lb/MWh-gross with SCPC units under its proposed BSER, and concludes that "given the higher CO_2 standard under this proposal . . . . [t]here is an estimated annual increase in CO_2 emissions of 1.1 million short tons per year."[608] But the analysis never characterizes or monetizes the impacts of this increase in emissions. Though the agency acknowledges that GHGs contribute to the endangerment of public health and welfare,[609] and though it took steps to quantify the private cost savings resulting from the proposed rule,[610] EPA states without explanation that "[it] d[id] not attempt to quantify the impacts of these increased emissions or economic value of these impacts."[611] In total, EPA devotes exactly 100 words to the "Climate

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603 *Id.*
604 *See, e.g.*, Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (Aug. 2016) [hereinafter IWG TSD 2016], available at https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.; *see also* 2015 RIA at 3-3 (noting that the IWG "used consensus-based decision-making . . . relied on existing academic literature and modeling . . . [and] took steps to disclose limitations and incorporate new information by considering public comments and revising the estimates as updated research became available").
605 2015 RIA at 3-4.
606 *Id.*
607 *Id.* at 3-5, 3-6.
608 NSPS Economic Impact Analysis, *supra* note 10 at 2-3.
609 *Id.* at 2-6.
610 *Id.* at 2-3 ("[T]his action will result in a cost savings of approximately $17 per MWh as compared to a SCPC facility with partial CCS, as would be required under the 2015 standard.").
611 *Id.* at 2-6.

Change Impacts" of the 1.1 million additional short tons of CO_2 (per unit, per year) flowing from its proposed rule.[612]

Second, EPA estimates that its proposed rule would result in "an increase of 500 short tons of SO_2 per year,"[613] but fails to monetize the health impacts resulting from this increase. SO_2 is a known precursor to ambient $PM_{2.5}$,[614] and EPA acknowledges that exposure to $PM_{2.5}$ is linked to health effects such as "premature mortality for adults and infants, cardiovascular morbidity such as heart attacks and hospital admissions, and respiratory morbidity such as asthma attacks, bronchitis, hospital and emergency room visits, work loss days, restricted activity days, and respiratory symptoms."[615] EPA also acknowledges that SO_2 can affect human health directly, as ambient concentrations of the pollutant "are associated with respiratory symptoms in children, emergency department visits, and hospitalizations for respiratory conditions."[616] Finally, EPA acknowledges that SO_2 emissions "can adversely impact vegetation and ecosystems through acidic deposition and nutrient enrichment, and can affect certain manmade materials, visibility, and climate."[617] The agency nonetheless "do[es] not attempt to quantify the number or economic value of these air pollution-related effects," and provides no explanation as to why.[618]

Similarly, EPA's failure to monetize and then consider/weigh the impacts of increased pollution under its proposed standard is arbitrary and unlawful. Agencies "cannot put a thumb on the scale by undervaluing the benefits and overvaluing the costs of more stringent standards."[619] Yet, in this proposal, EPA has done exactly that. The EIA monetizes the private cost savings to individual operators resulting from the weakened standard,[620] but does not even "attempt to quantify the impacts of the[] increased [CO_2] emissions or economic value of these impacts."[621] Neither does the EIA "attempt to quantify the number or economic value of the[] air pollution-related effects" of increased SO_2 emissions under the proposed rule.[622] EPA, of course, did monetize these benefits in its 2015 RIA,[623] and its unexplained failure to do so here is yet another indicia of arbitrariness. Moreover, such an approach is deeply at odds with rational decisionmaking, and courts have made clear that one-sided, incomplete analyses such as this one are unlawful. In *CBD v. NHTSA*, for example, the U.S. Court of Appeals for the Ninth Circuit held that NHTSA's failure to monetize the benefits of carbon emission reductions was arbitrary and capricious given the agency's monetization of other uncertain costs and benefits resulting from its vehicle efficiency standard.[624] The Court found it particularly noteworthy that carbon emission reductions were "the most significant benefit" of more stringent standards, and that NHTSA had assigned this benefit "no value" despite the fact that "it is possible to monetize the

[612] *Id.*
[613] *Id.* at 2-3.
[614] *Id.* at 2-6.
[615] *Id.* at 2-7.
[616] *Id.*
[617] *Id.*
[618] *Id.* at 2-6, 2-7.
[619] *Ctr. For Biological Diversity v. NHTSA*, 538 F.3d 1172, 1198 (9th Cir. 2008).
[620] *See* NSPS Economic Impact Analysis, *supra* note 10, at 2-3.
[621] NSPS Economic Impact Analysis, *supra* note 10 at 2-6.
[622] *Id.* at 2-6, 2-7.
[623] 2015 RIA at 5-7 (Table 5-2).
[624] *Ctr. For Biological Diversity v. NHTSA*, 538 F.3d at 1201.

benefit."[625] EPA's analysis here mirrors NHTSA's flawed evaluation. The proposed standard would result in "an estimated annual increase in CO_2 emissions of 1.1 million short tons per year" for every new SCPC unit constructed, and yet EPA assigns no monetary value to the impacts of this increase in climate pollution. This deficiency is arbitrary and unlawful,[626] as is EPA's failure to monetize and consider the impacts of increased SO_2 pollution.

Further, the agency's approach runs afoul of Executive Order 12,866, which requires agencies undertaking significant regulatory actions to assess the costs and benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity)[627] But EPA has failed to fully and fairly assess costs and benefits.[628] EPA's dereliction also runs afoul of President Trump's Executive Order 13,783, which assumes that EPA and other federal agencies will continue to "monetiz[e] the value of changes in greenhouse gas emissions resulting from regulations," and directs these agencies to "ensure . . . that any such estimates are consistent with the guidance contained in OMB Circular A-4."[629] OMB Circular A-4, in turn, states that agency analyses should be based "on the best reasonably obtainable scientific, technical, and economic information available,"[630] and directs agencies to monetize costs and benefits whenever feasible.[631] Crucially, these directives evince a steadfast commitment to rational, even-handed assessment of costs and benefits. EPA's decision to only monetize unit-level cost savings is inconsistent with this commitment to rationality. EPA clearly recognizes the importance of assessing the impacts of its revised determination at the unit level. The agency notes in its 2018 EIA that, although construction of new coal-fired generation is unlikely, "an operator may find it desirable to construct a new coal-fired EGU for" various reasons.[632] This mirrors EPA's observation in the 2015 RIA that although "it is unlikely that a new non-compliant coal-fired unit would be constructed . . . an operator may [nonetheless] have reasons to choose to construct a conventional coal-fired power plant."[633] Because the agency projects that no new coal-fired units will be built, the only rational approach to assessing costs and benefits consistent with the directives discussed above is to examine the costs and benefits at a single unit, which reflect the most realistic non-zero estimates for these values. Having decided to evaluate the unit-level impacts of its revised determination, EPA cannot put its "thumb on the scale" by monetizing only the cost savings to individual units.[634]

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[625] *Id.* at 1199-1200.
[626] *See State Farm*, 463 U.S. 29, 41-43 (1983) (an agency rule is arbitrary and capricious if the agency "entirely failed to consider an important aspect of the problem"); *see also High County Conservation Advocates v. Forest Service* (arbitrary and capricious for agency "to quantify the benefits of the lease modifications and then explain that a similar analysis of the costs [of carbon pollution] was impossible when such an analysis was in fact possible"); *see generally* Peter Howard & Jason Schwartz, *Think Global: International Reciprocity as Justification for a Global Social Cost of Carbon*, 42 COLUMBIA J. ENVTL. L. 203 (2017).
[627] E.O. 12,866, *Regulatory Planning and Review*, 58 Fed. Reg. 51,735 (Oct. 4, 1993) (emphasis added).
[628] *Michigan v. EPA*, 135 S. Ct. at 2707 ("[R]easonable regulation ordinarily requires paying attention to the advantages *and* the disadvantages of agency decisions.").
[629] E.O. 13,783, *Promoting Energy Independence and Economic Growth*, 82 Fed. Reg. 16,093 (Mar. 31, 2017).
[630] OMB Circular A-4 at 17.
[631] *Id.* at 27 ("You should monetize quantitative estimates whenever possible.").
[632] NSPS Economic Impact Analysis, *supra* note 10, at 2-2.
[633] 2015 RIA at 5-16.
[634] *Ctr. For Biological Diversity v. NHTSA*, 538 F.3d at 1198.

EPA's omission is particularly egregious given the feasibility of monetizing the impacts of increases in CO_2 and SO_2 pollution. Indeed, per-ton estimates of the benefits of reducing these pollutants are readily available. In the 2015 RIA, for example, EPA relied on IWG's SC-CO_2 estimates in monetizing incremental changes in CO_2 emissions.[635] Accordingly, EPA used values of $13, $41, $62, and $120 per ton of CO_2 emissions to evaluate the costs and benefits of its final standards.[636] These cost estimates have been consistently used in rulemakings by various agencies since their publication.[637] Similarly, EPA has consistently demonstrated the feasibility of monetizing the impacts of SO_2 and $PM_{2.5}$ reductions. In the 2015 RIA, for example, EPA concluded that "[n]otwithstanding [analytical] limitations, reducing one thousand tons of annual SO_2 from U.S. power sector sources has been estimated to yield between four and nine incidences of premature mortality avoided and monetized $PM_{2.5}$-related health benefits (including these incidences of premature mortality avoided) between" $34 million and $85 million in 2020 (2011$).[638] EPA also monetized the impacts of $PM_{2.5}$ reductions in the Mercury and Air Toxics Standards, finding that the avoided $PM_{2.5}$-related impacts as a result of the rule would yield between $36 billion and $89 billion (2007$) in benefits.[639] These examples make clear the feasibility of monetizing the impacts of increased CO_2, SO_2, and $PM_{2.5}$ emissions.

C. EPA's Unit-Level Comparison Unlawfully Fails to Consider an Adequate Range of Alternatives

EPA's unit-level comparison of emissions fails to include the appropriate range of generation technologies. The 2015 RIA compared the illustrative emissions profiles of compliant SCPC units co-firing natural gas, IGCC units co-firing nature gas, and NGCC units with that of non-compliant coal units,[640] and then compared the incremental benefits of the emissions reductions from the compliant units relative to the non-compliant units.[641] The 2018 EIA fails to undertake any similar analysis. The analysis makes no mention of how emissions from compliant NGCC units or SCPC and IGCC units co-firing natural gas compare with coal-generation under the current NSPS or this Proposal, and consequently does not assess the relative emissions reduction benefits of these forms of generation. EPA's failure in this regard highlights the agency's failure to adequately consider alternative systems of emission reduction, and underscores that rejection of these options as BSER was arbitrary and capricious. In addition, EPA's failure to consider these different form of generation tends to overstate the benefits and

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[635] 2015 RIA at 3-3.
[636] *Id.* at 3-6.
[637] *See, e.g.*, Greenhouse Gas Emissions Standards and Corporate Average Fuel Economy Standards for Light-Duty Vehicles, 75 Fed. Reg. 25,324 (May 7, 2010); National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9,304 (Feb. 16, 2012).
[638] 2015 RIA at 3-10, 3-11.
[639] 77 Fed. Reg. 9,304, 9,306 (Feb. 16, 2012) (Table 2).
[640] *See* 2015 RIA at 5-4 (Table 5-1).
[641] *See* 2015 RIA at 5-7 (Table 5-2) (comparing compliant NGCC units to non-compliant SCPC and IGCC units); *id.* at 5-11 (Table 5-4) (comparing compliant SCPC and IGCC units co-firing natural gas with non-compliant SCPC and IGCC units).

minimize the societal costs of the Proposal, because NGCC is the type of new generation most likely to be constructed at all but the highest natural gas price scenarios.[642]

D. EPA Must Apply the Interagency Working Group SCC Estimates.

The unit-level analysis in any rule EPA finalizes must use the IWG's 2016 SCC estimate to monetize the impacts of increased carbon pollution expected to result from the revised standards. Though widely regarded as conservative,[643] the IWG's 2016 estimate—including its "central" SCC estimate of around $52 per ton[644]—is the best tool the federal government has thus far developed for valuing the impacts of greenhouse gas emissions. These estimates were formulated using "the most widely used and widely cited models in the economic literature that link physical impacts to economic damages for the purposes of estimating the SCC."[645] Moreover, the estimates reflect "consensus-based decision making," rely on "existing academic literature and models, including technical assistance from outside resources," and "incorporate new information by considering public comments and revising the estimates as updated research [becomes] available."[646]

Principles of rational decision-making require that EPA use the best available science and analytic techniques in quantifying the costs and benefits of its regulations. The IWG's SCC estimates—used in at least 34 proposed rulemakings since 2009[647]—embody a rigorous, transparent, state-of-the-art approach to measuring the economic damages caused by the climate change impacts of CO_2 emissions. EPA must therefore use these estimates to monetize the unit-level impacts of its revised determination.

E. EDF's Analysis Shows That, At the Unit-Level, Benefits from Partial CCS Would Be Greater Now Relative to Those Calculated by EPA in 2015.

Had EPA properly evaluated and monetized the benefits of CCS, it would have found those benefits to be substantially greater than reflected in the 2015 Final Rule. Benefits from

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[642] *See* NSPS Economic Impact Analysis at 3-27. As the EIA suggests, at high-end gas price scenarios of $10 and 11/MMBtu, the Proposal would encourage construction of high-emitting supercritical pulverized control EGUs in lieu of NGCC. Because NGCC emits lower levels of criteria pollution and CO_2 than even a new coal-fired EGU compliant with the current NSPS, EPA's comparison tends to understate the benefits of the current standard by excluding comparisons of emissions and costs with NGCC.
[643] *See, e.g.*, Richard L. Revesz et al., *Global Warming: Improve Economic Models of Climate Change*, 508 Nature 173 (2014); *see also* R.S. Pindyck, *The Social Cost of Carbon Revisited,* Nat'l Bureau of Econ. Res. Working Paper w22807, at 4-5 (Nov. 2016) (estimating the social cost of carbon as being between roughly $100 and $200 per metric ton).
[644] *See* IWG TSD 2016 at 16 (Table 2) (inflation-adjusted 2020 emissions in 2019 dollars).
[645] Interagency Working Group on the Social Cost of Carbon, *Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12,866* at 7 (July 2015) [hereinafter IWG Response to Comments]; *see also* National Academy of Sciences, *Hidden Cost of Energy: Unpriced Consequences of Energy Production and Use* at 301 (2010) (referring to DICE, FUND, and PAGE as "the most widely used impact assessment models").
[646] Government Accountability Office, REGULATORY IMPACT ANALYSIS: DEVELOPMENT OF SOCIAL COST OF CARBON ESTIMATES at 8 (2014); *see also* IWG Response to Comments, at 39 ("[T]he public has had ample opportunities to comment on the SCC estimates and methodology.").
[647] IWG Response to Comments, at 4; *see also* JANE A. LEGGETT, CONG. RESEARCH SERV., R44657, FEDERAL CITATIONS TO THE SOCIAL COST OF GREENHOUSE GASES at 2-12, Table 1 (2017).

CCS in the 2018 proposal are more than two times the benefits calculated in 2015 after adjusting for inflation. This is due to assumed net emission rates for SCPC in the 2018 EIA as compared to 2015 RIA. In the 2015 rule, EPA calculated benefits of 200 lb/MWh CO_2[648] while in the 2018 proposal EPA calculated benefits of 500 lb/MWh CO_2. [649] The tables below compare estimated benefits published in the 2015 RIA to estimated benefits calculated using the same methodology and the emission rates published in the 2018 EIA:

Combined Benefits of Partial CCS, 2015 Rulemaking (2016$) and 2018 Proposal (2016$)

	PM2.5 Discount Rate			
SCC Discount Rate	*3% (2015 RIA, 2016$)*	*3% (2018 EIA, 2016$)*	*7% (2015 RIA, 2016$)*	*7% (2018 EIA, 2016$)*
5%	$3.5-$6.0	$7.8-$13.4	$3.2-$5.6	$7.4-$12.4
3%	$6.8-$9.4	$15.6-$21.2	$6.6-$9.0	$15.2-$20.2
2.5%	$9.2-$11.8	$21.1-$26.6	$9.0-$11.3	$20.6-$25.6
3% (95th percentile)	$16.1-$18.7	$37.9-$43.5	$15.9-$18.2	$37.5-$42.5

Emissions Rates (lb/MWh-net) for New Coal-Fired Generating Units of 600 MWnet Capacity

	SCPC+Partial CCS		*SCPC*	
	2015 RIA	2018 EIA	2015 RIA	2018 EIA
SO_2	0.61	0.61	0.71	0.83
NO_X	0.75	0.75	0.74	0.74
CO_2	1500	1500	1700	2000

The second table captures the 2015 RIA's finding that a non-compliant SCPC unit would emit 1,700 lb/MWh-net CO_2, while a compliant SCPC unit using partial CCS would emit only 1,500 lb/MWh-net CO_2, meaning that partial CCS would reduce a unit's CO_2 emission rate by 200 lb/MWh-net. The second table also captures the 2018 EIA's updated finding that an SCPC unit would now emit 2,000 lb/MWh-net CO_2, while an SCPC unit using partial CCS would still emit only 1,500 lb/MWh-net CO_2, meaning that partial CCS would now reduce a unit's CO_2 emission rate by 500 lb/MWh-net. In other words, according to EPA's calculations, partial CCS would lead to a more substantial reduction in CO_2 emissions rates than previously determined (200 lb/MWh-net versus 500 lb/MWh-net). These updated figures are reflected in the second and fourth columns of the first table, which show the combined emissions reduction benefits of partial CCS based on the 2018 EIA's calculations, including the 500 lb/MWh-net CO_2 reduction.

Importantly, these columns show that partial CCS would yield net benefits given EPA's cost estimates. EPA concludes in the 2018 EIA that "[its] action will result in a cost savings of approximately $17 per MWh as compared to a SCPC facility with partial CCS."[650] Using the

[648] *See* 2015 RIA at 5-4 (Table 5-1).
[649] NSPS Economic Impact Analysis, *supra* note 10, at 2-4 (Table 2-1).
[650] *Id.* at 2-3; *see also id.* at 2-4 (Table 2-1) (showing that the LCOE for an SCPC unit would decrease from $99 to $82 as a result of EPA's revised determination).

SCC's "central" discount rate of 3 percent,[651] however, the second and fourth columns show that partial CCS would result in benefits of $15.6-$21.2 using a 3 percent discount rate for PM2.5, or benefits of $15.2-$20.2 using a 7 percent discount rate for PM2.5. In either case, partial CCS results in net benefits over the greater part of the range.[652] EPA must therefore explain why it is choosing to impose net costs on society (by foregoing these net benefits) as a result of this rulemaking.

The Proposal's EIA fails to adequately describe the increase in emissions that would occur from each additional unit under EPA's revised determination. Then, for the emissions increases it does describe, the EIA fails to monetize and evaluate the impacts of those changes. These failures are arbitrary and unlawful. Crucially, had EPA taken steps to monetize the projected emissions increases using the best available scientific and analytic tools, the above analysis indicates that the foregone benefits of partial CCS would exceed the cost savings estimated by EPA. Any final rule failing to address these flaws and explain EPA's imposition of net costs would be unlawful.

IV. Additional Concerns

A. EPA Has Unlawfully Failed to Disclose Any Information About Its Review of the 2015 Final Rule Conducted Pursuant to Executive Order 13,783

The Proposed Rule states that EPA undertook review of the 2015 NSPS for coal-fired power plants pursuant to Executive Order 13,783, "Promoting Energy Independence and Economic Growth."[653] "[T]hat review . . . led the EPA to propose to revise the BSER determinations for new, reconstructed, and modified coal-fired EGUs."[654] The Agency's failure to disclose to the public any information regarding its review under Executive Order 13,783—which EPA itself identifies as the origin of its revised BSER determination,[655] a decision central to this Proposal—violates procedural and substantive requirements of the Clean Air Act.

The preamble to the Proposed Rule and accompanying record provide no information concerning the content of this review, including what documents EPA generated or relied on in performing the review; how EPA interpreted Executive Order 13,783; or what provisions of the Executive Order EPA relied upon in deciding to revise its BSER determinations for new, reconstructed and modified coal-fired EGUs.

This lack of information is unlawful. It violates the Clean Air Act's requirement that EPA place in the docket for a proposed rule the information and analyses the Agency relied upon in

[651] *See* IWG TSD 2016 at 4 ("[T]he central value is the average of [SCC] estimates based on the 3 percent discount rate."); IWG Response to Comments at 22 ("The central value, 3 percent, is consistent with estimates provided in the economics literature and OMB's Circular A-4 guidance for the consumption rate of interest.").
[652] These ranges reflect that, for each discount rate, EPA's 2015 RIA used "two alternative primary estimates of PM2.5-related mortality impacts: a lower primary estimate based on Krewski et al. (2009) and a higher primary estimate based on Lepeule et al. (2012)." 2015 RIA at 3-11.
[653] Proposal, 83 Fed. Reg. at 65,429; *see also* Exec. Order No. 13,783, 82 Fed. Reg. 16,093 (Mar. 31, 2017).
[654] Proposal, 83 Fed. Reg. at 65,429.
[655] *Id.* at 65,429.

developing it, [656] and also violates general requirements of reasoned decision-making and meaningful public comment. Furthermore, EPA has failed to explain how it interpreted the substantive language in the Executive Order, and how reliance on such factors as promoting fossil fuel development is consistent with the Clean Air Act provisions at issue here. Finally, the agency has utterly failed to show why it determined that its previous BSER determination is inconsistent with (unspecified) requirements of the Executive Order, let alone address its own detailed determinations from 2015 showing that the 2015 Final Rule was fully compatible with a thriving economy and reliable electricity system. [657] This lack of transparency is consequential—by hiding this foundational information, EPA precludes the public's ability to respond to and rebut any improper interpretations of the Clean Air Act or unfounded assertions regarding economic impacts, reliability, or other considerations.

This lack of transparency regarding this review—which the agency maintains was the foundation for this proceeding—is inconsistent with the Clean Air Act and renders this Proposal unlawful.

B. EPA's Interpretation of the Energy Policy Act of 2005 is Proper and Should Not Be Disturbed.

We support EPA's decision to uphold its prior interpretation of the Energy Policy Act of 2005 (EPAct '05). While EPA is rightfully not proposing to re-open or revise the interpretation, we reiterate our comments on the 2014 proposed NSPS here and support the agency's interpretation of EPAct '05 sections 402(i), 421(a), and 1307(b).[658] EPA's interpretation of those provisions—under which EPA is permitted to consider the performance of EPAct-supported projects in determining that a control technology is "adequately demonstrated," so long as those projects are not the *sole* basis for that determination—is the most consistent interpretation with the language and purposes of the statute and is reasonable.

Under the plain language of sections 402(i) and 421(a) these provisions only prohibit EPA from relying "solely" on EPAct-funded facilities in determining that a technology is adequately demonstrated.[659]

EPAct '05's addition to the tax code is similarly limited. Section 1307(b) states only that an EPAct-supported facility cannot be "considered to indicate" that a technology is adequately demonstrated.[660] The most logical reading of this provision is that EPAct-supported facilities cannot independently indicate that a technology is "adequately demonstrated." Thus, the ban on "consider[ing]" would be a ban on EPA *deeming* a technology to be proven as technically feasible simply because it is used at an EPAct-supported facility. This reading is also consistent

[656] 42 U.S.C. § 7607(d)(3).
[657] *See* 2015 Final Rule, 80 Fed. Reg. at 64,642 (Oct. 23, 2015) ("[T]he EPA believes this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.").
[658] Proposal, 83 Fed. Reg. at 65,444 n. 88; Comments of Environmental Defense Fund, the Natural Resources Defense Council, and Western Resource Advocates on Notice of Data Availability (NODA) in Support of Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 10,750 (Feb. 26, 2014) at 2-7 (May 9, 2014).
[659] *See* 42 U.S.C. § 15962(i); *id.* §§ 13573(e), 13574(d).
[660] 26 U.S.C. § 48A(g).

with the numerous other instances in the same statute in which Congress uses the phrase "considered to" to mean "deemed."[661, 662]

Interpreting "considered to indicate" to mean "deemed to prove" reads 1307(b) consistently with sections 402(i) and 421(a) of EPAct '05 which, as noted earlier, simply prohibit EPA from relying "solely" on EPAct-funded projects in determining that a technology is adequately demonstrated. These provisions should be read together because there is no indication that Congress intended projects receiving tax incentives to be treated differently from projects receiving other kinds of federal support under EPAct '05. *Cf. Erlenbaugh v. United States,* 409 U.S. 239, 245 (1972) (two statutes "intended to serve the same function" may be construed similarly to resolve any ambiguities).

This is the interpretation that most furthers the broad purposes of EPAct '05 and the Clean Air Act. Section 421's Clean Air Coal Program's purpose is "increas[ing] the marketplace

[661] *See* EPAct '05 § 105(b), 42 U.S.C. § 8287 ("shall be considered to have been entered into under that section"); EPAct '05 § 135(b)(1), 42 U.S.C. § 6293(b)(10(C) ("shall be considered to be the testing requirements"); EPAct '05 § 323, 33 U.S.C. § 1362(24) ("may be considered to be construction activities"); EPAct '05 § 384, 43 U.S.C. § 1356a(b)(4)(C) ("For the purposes of subparagraph (B)(ii), the coastline for coastal political subdivisions in the State of Louisiana without a coastline shall be considered to be 1⁄3 the average length of the coastline of all coastal political subdivisions with a coastline in the State of Louisiana."); EPAct '05 § 402(i), 42 U.S.C. § 15962(i) ("No 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"); EPAct '05 § 651(e)(2), 42 U.S.C. § 2111(c) ("shall not be considered to be low-level radioactive waste"); EPAct '05 § 651(e)(4)(C)(iii)(II), 42 U.S.C. § 16041(e)(4)(C)(iii)(II) ("shall be considered to include byproduct material"); EPAct '05 § 752(b)(5) ("whether the emission reduction credits may be considered to be additional"); EPAct '05 § 999B(c)(3)(A), ("unless such relationships or interests would be considered to be remote or inconsequential"); EPAct '05 § 1009(b)(8), 42 U.S.C. § 5911(b) ("shall be considered to be a major rule"); EPAct '05 § 1233(a), 16 U.S.C. § 824q(j)(1) ("shall be considered to hold firm transmission rights"); EPAct '05 § 1300(b) ("the reference shall be considered to be made to a section or other provision of the Internal Revenue Code of 1986"); EPAct '05 § 1402(c)(1), 42 U.S.C. § 16491(c)(1) ("considered to be a reasonable regulation of commerce"); EPAct '05 § 1402(c)(1), 42 U.S.C. § 16491(c)(2) ("not be considered to impose an undue burden on interstate commerce"); EPAct '05 § 1501(a)(2), ("shall be considered to be the equivalent").

[662] Supporting the reasonableness of EPA's interpretation, Federal courts themselves frequently use the phrase "considered to indicate" to mean "deemed to signify." *See, e.g., Foxcroft v. Mallett*, 45 U.S. 353, 378 (1846) ("The reference to the deed might as properly be considered to indicate the interests as the premises just received."); *Lanning v. SEPTA*, 181 F.3d 478, 497 (3d Cir. 1999) ("The substitution of the word 'consistent' was considered to indicate a standard less stringent than would 'required.'"); *Ziegler v. Sullivan*, 894 F.2d 1337, 1990, U.S. App. LEXIS 1334, at *9 (6th Cir. 1990) ("The I.Q. result of 97 was not considered to indicate a great degree of regression from a previously higher level of functioning."); *United States ex rel. Eddies Sales & Leasing, Inc. v. Fed. Ins. Co.*, 634 F.2d 1050, 1052-1053 (10th Cir. 1980) ("Other factors generally considered to indicate that an agreement is in substance a secured installment sale clothed in lease terminology include . . . ."); *United States v. Bobo*, 586 F.2d 355, 366 (5th Cir. 1978) ("The only statement by the judge that could reasonably be considered to indicate any bias against Rowan was clearly based on facts that the judge had learned in the course of prior proceedings in the case."); *Joyce v. United States*, 454 F.2d 971, 982 (D.C. Cir. 1971) ("it is narrowly drawn to proscribe only those physical acts which may be considered to indicate an intention to cast 'contempt' upon the flag"); *Monahan v. R.R. Ret. Bd.*, 181 F.2d 751, 752 (7th Cir. 1950) ("He found no physical impairment other than generalized arteriosclerosis of a moderate degree, and blood pressure which might be considered to indicate mild hypertension."); *Kelly v. United States*, 47 F.2d 122, 125 (5th Cir. 1931) ("such a possession by appellant of substantial amounts of unaccounted for money and merchandise so short a time prior to his bankruptcy as, in the absence of any explanation as to what became of those assets, reasonably might be considered to indicate that his possession or control thereof continued after bankruptcy").

acceptance of clean coal generation and pollution control equipment and processes."[663] Similarly, Congress intended the Clean Coal Power Initiative "to ensure that coal remains a major component of national energy policy," and "to facilitate research, development and deployment of advanced coal gasification and combustion technologies for electric power generation."[664] The statutory language and legislative history demonstrate that EPAct '05 was meant to advance the commercial availability and wide scale deployment of clean coal technology.

EPA making a positive determination that a technology is adequately demonstrated after considering the existence or performance of an EPAct '05-supported project as just one data point alongside other record evidence and selecting such technology as the BSER and basis for a performance standard would clearly further the purpose of EPAct'05. And wide deployment of cutting-edge technology to curb harmful air pollution is the purpose of Section 111 performance standards.[665] Thus, the most logical reading of EPAct '05 sections 402(i), 421(a), and 1307(b) fully supports EPA's interpretation that it may consider EPAct-supported facilities in combination with other evidence in determining whether CCS is adequately demonstrated—as it can in other aspects of the section 111 BSER analysis, including efficacy in securing emission reductions and cost.

C. EPA's Proposal to Waive the NSPS for "Commercial Demonstration" Projects is Unlawful, Arbitrary and Capricious

Not satisfied with weakening the 2015 Final Rule to a level that is far less stringent than a modern, pulverized coal-fired power plant can achieve, EPA also proposes to create a "commercial demonstration permit" (CDP) program that would allow individual affected EGUs to seek a waiver of the NSPS and discharge even greater quantities of carbon pollution.[666] Purportedly based on a program that is currently codified in Subpart Da,[667] EPA's proposed CDP would allow the Administrator to establish a less stringent standard of performance for new EGUs that utilize one of a selected list of "emerging technologies." EPA proposes that these waivers would allow new EGUs to emit 100 pounds per megawatt-hour more than EGUs subject

[663] *See* EPAct '05 § 421(a), 42 U.S.C. § 13571(2).
[664] S. Rep. No. 109-78, at 3 (2005).
[665] *See Sierra Club v. Costle*, 657 F.2d 298, 364 (D.C. Cir. 1981) ("Recognizing that the Clean Air Act is a technology-forcing statute, we believe EPA does have authority to hold the industry to a standard of improved design and operational advances" when setting standards under section 111); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) ("[s]ection 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present"); *id.* (holding that EPA may make a reasonable "projection based on existing technology" when selecting the best system of emission reduction); S. Rep. No. 91-1196, at 16 (1970) (new source performance standards should reflect "the degree of emission control that has been or can be achieved through the application [of] technology which is available or normally can be made available. This does not mean that the technology must be in actual, routine use somewhere."); *id.* at 17 ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources . . . ."); *see also* H.R. Rep. No. 95-294, at 186 (1977) (noting that one of the purposes of new source performance standards is to create an incentive for technological innovation by providing a "guaranteed market" for new control technology).
[666] Proposal, 83 Fed. Reg. at 65,457.
[667] 40 C.F.R. 60.47Da.

to the revised NSPS EPA has proposed[668]—which itself would allow new EGUs to emit at far higher rates than most *existing* coal-fired power plants can achieve.

These proposed CDP provisions are inconsistent with section 111 of the Clean Air Act, which already provides a specific and carefully-designed mechanism for EPA to adjust the NSPS to accommodate innovative and emerging technologies. As the courts have repeatedly held, it is "axiomatic that administrative agencies may act only pursuant to authority delegated to them by Congress."[669] If EPA wishes to allow a waiver of the NSPS in order to "encourage the development of new technologies,"[670] it must "point to something in either the Clean Air Act or the APA that gives it authority" to do so.[671] Yet the sole source of authority EPA identifies in the Proposal is the agency's general obligation to avoid "exorbitantly costly" standards in selecting a BSER under section 111.[672] Neither this general statutory principle nor the case EPA cites to, however, authorizes the agency to *waive* an NSPS and establish a less stringent standard that does not reflect the degree of emission reduction achievable through a duly-designated BSER—whether that waiver is granted to encourage technological innovation or for any other purpose.

To the contrary, the plain text of section 111(b) requires EPA to list each category of stationary sources that causes or contributes significantly to endangerment of public health and welfare, and to "establish Federal standards of performance for new sources within such category."[673] While the Administrator is authorized to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards,"[674] the statute is clear that all new sources within a category or subcategory must be subject to a "standard of performance"—a defined term that requires an emission limitation reflecting a best system of emission reduction.[675] A waiver establishing an alternative standard that is not consistent with the BSER contravenes this clear statutory command.

Moreover, as the Proposal acknowledges, section 111(j) of the Clean Air Act *already* provides an extremely detailed mechanism for the Administrator to waive such standards of performance for the purposes of promoting innovative systems of emission reduction. Under section 111(j), "any person proposing to own or operate a new source" may seek a waiver from the Administrator of any section 111 requirement "to encourage the use of an innovative technological system or systems of continuous emission reduction."[676] The statute prescribes detailed procedural requirements for issuing such waivers, including public notice and comment; consent by the governor of the state where the new source is to be located; and specific findings that the Administrator must make, *including* a "substantial likelihood" that the proposed system

[668] Proposal, 83 Fed. Reg. 65,458.
[669] *Clean Air Council v. Pruitt*, 862 F.3d 1, 9 (D.C. Cir. 2017) (quoting *Verizon v. FCC*, 740 F.3d 623, 632 (D.C. Cir. 2014)).
[670] Proposal, 83 Fed. Reg. 65,458.
[671] *Clean Air Council v. Pruitt*, 862 F.3d at 9.
[672] Proposal, 83 Fed. Reg. at 65,457 (citing *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427 (D.C. Cir. 1973)). The Proposal's citation to *Essex Chemical Corp.* contains an incorrect page reference to the *Federal Reporter*, and does not specify the particular page of the opinion that EPA relies upon. Based on the description in the preamble to the Proposal, we assume that EPA intended to cite to *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d at 433.
[673] 42 U.S.C. § 7411(b)(1)(B).
[674] 42 U.S.C. § 7411(b)(2).
[675] 42 U.S.C. § 7411(a).
[676] 42 U.S.C. § 7411(j)(1)(A).

will achieve greater reductions than the standard that would otherwise apply, and that the system will not pose an "unreasonable risk to public health, welfare, or safety . . . ."[677] The statute also imposes specific time limitations on the number and duration of such waivers.[678]

That Congress provided such a detailed and comprehensive program is a strong indication that EPA *lacks* free-floating statutory authority to grant innovation waivers outside of this framework.[679] Indeed, the Proposal itself indicates that the purpose of the proposed CDP is to circumvent section 111(j), because "the innovative technology waiver under section 111(j) of the CAA does not by itself offer adequate support for certain capital-intensive technologies . . . ."[680] And the CDP provisions EPA has proposed provide none of the carefully-designed protections that Congress included in section 111(j), such as public notice and comment; consent by the governor of the affected state; a finding that the proposed system will achieve greater reductions than the standard that would otherwise apply; and a time limit to ensure that the source does not indefinitely discharge pollution at levels higher than an applicable NSPS. The proposed CDP would do an end-run around the carefully calibrated constraints Congress included for innovative technology waivers in section 111(j). For this reason, the proposed CDP provision is unlawful and should be withdrawn.

D. Subcategorization of Steam EGUs by Fuel Type or Duty Cycle Is Not Justified and Reliance on a Part Load Heat Input-based Standard Would be Harmful

EPA is soliciting comment on subcategorization of steam EGUs by fuel type or duty cycle. Specifically, the agency is considering a subcategory for steam EGUs that operate at less than 65 percent duty cycle on a rolling average basis during any 12-operating month period.[681] EPA is also soliciting comment on establishing a part load heat input-based standard as an alternate or in place of a low duty cycle output-based standard.[682]

There is no justification for EPA to subcategorize steam EGUs by fuel type or duty cycle. In fact, relying on a part load heat input-based standard would be harmful since it focuses solely on the type of fuel burned and fails to recognize the environmental benefit of efficient turbine operation—and therefore would not incentivize turbine efficiency improvements. Subcategorization in this manner would only encourage or facilitate low duty cycle operation that EPA admits is a far less efficient mode of operation for new EGUs.[683] It would also be arbitrary for EPA to subcategorize only in the direction of allowing *more* pollution but not for the purpose of securing additional reductions from new EGUs, which would find it feasible to

[677] 42 U.S.C. § 7411(j)(1)(A).
[678] 42 U.S.C. § 7411(j)(1)(C)-(D).
[679] *See EPA v. Nat'l Crushed Stone Ass'n,* 449 U.S. 64, 80-81 (1980) (holding that "economic hardship" waivers from certain Clean Water Act requirements were unlawful where Congress had clearly anticipated the problem and "specifically added two other provisions to address the problem of economic hardship"); *Clean Air Council*, 862 F.3d at 9 (finding EPA had no inherent authority to stay a rule for purposes of reconsideration where Congress had already specified a procedure for such stays).
[680] Proposal, 83 Fed. Reg. at 65,457.
[681] Proposal, 83 Fed. Reg. at 65,456.
[682] *Id*. at 65,457.
[683] *Id.* at 65,456 ("efficiency is reduced at. . . [lower] load").

implement CCS, co-firing, or other systems of emission reduction more effective than EPA's proposed BSER.

Subcategorization by duty cycle is also not necessary. As we already discussed in detail in section II.H.ii of our comments above and as demonstrated by Andover Technology Partner's report, EPA's proposed standards are readily achievable by the existing coal fleet today.[684] Indeed, EPA's own analysis shows that for bituminous and subbituminous fuels the proposed standards are readily possible with subcritical steam conditions at 99.5% confidence rate.[685] This already takes into consideration the variability in coal fleet operation including partial load.

Finally, as we also explained in section II.H.v of our comments, coal-fired EGUs have relatively high capital costs and new coal EGUs will therefore only be developed in situations where high utilization rates are expected.[686] According to Andover, EPA's own analysis of hourly emission data and operating time versus capacity factors demonstrates that coal EGUs tend to operate primarily at capacity factors associated with the lowest emission rate.[687]

E. EPA Has No Basis to Change Its Treatment of Non-Baseload Combustion Turbines

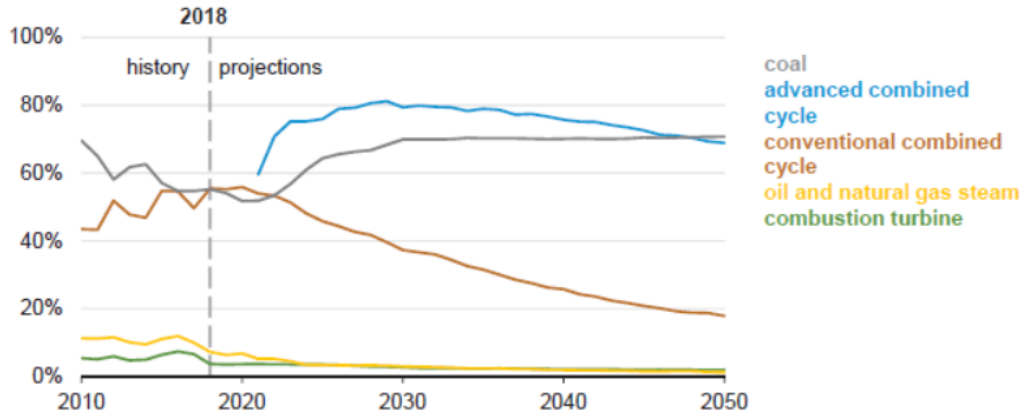
In the 2015 Final Rule, EPA set separate standards for baseload and non-baseload combustion turbines. Although EPA is not re-opening the standards promulgated in the 2015 Final Rule for combustion turbines, the agency is soliciting comment on whether increased utilization of wind and solar resources, combined with low natural gas prices, could lead to higher utilization of new simple cycle aeroderivative combustion turbines in excess of the non-baseload threshold.[688] EPA is also requesting comment on whether under such circumstances, more efficient aeroderivative combustion turbines would be displaced by higher emitting resources resulting in higher overall emissions.[689]

We find no basis for EPA to change its treatment of non-baseload combustion turbines. As evidenced by EIA's recent 2019 Annual Energy Outlook and shown in Figure 9, higher penetration of wind and solar resources and low natural gas prices are projected to result in higher utilization of new advanced natural gas combined cycle units.[690] New advanced natural gas combined cycle units are more flexible and have higher efficiencies and lower costs compared to other fossil-fired generating technologies including conventional natural gas combined cycle and simple cycle combustion turbines. According to EIA, new advanced combined cycle natural gas units are projected to have the highest utilization of all fossil-fired generating technologies while utilization of lower efficiency conventional combined cycle units

[684] ANDOVER 2019 COAL STEAM EGU REPORT.
[685] *Id*. at 1
[686] *Id*. at 17
[687] *Id*.
[688] Proposal, 83 Fed. Reg. at 65,460-61.
[689] *Id*. at 65,461.
[690] U.S. Energy Information Administration, ANNUAL ENERGY OUTLOOK 2019 WITH PROJECTIONS TO 2050 111-12 (Jan. 24, 2019), https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

is projected to decline and simple cycle combustion turbine utilization is projected to remain flat.[691]

Figure 9: Utilization of Fossil-Fired Capacity (Reference Case)[692]



Therefore, there is no reason to believe there would be higher utilization of new simple cycle aeroderivative combustion turbines or that failing to accommodate a higher utilization of those simple cycle turbines would lead to higher emissions. To the contrary, to the extent that fossil-fired generation shifts to more efficient advanced natural gas combined cycle units, overall emissions should decline.

Lastly, EPA appropriately acknowledges in the preamble that it does not have a specific proposed course of action with regard to the NSPS for combustion turbines, and commits to undertake a new rulemaking if it determines that further changes to the NSPS are warranted.[693] We agree that if EPA decides to pursue any change to these standards, it must formulate a new proposal and provide the public an opportunity to comment.[694]

F. EPA's Existing Standard For Baseload Combustion Turbines Does Not Reflect The Degree of Reduction that Is Achievable

In the 2015 Final Rule, EPA set standards for baseload combustion turbines or natural gas combined cycle units at 1,000 lb CO_2/MWh-gross.[695] The agency is not proposing to re-open those standards for combustion turbines. However, a recent report and analysis by Andover Technology Partners using EPA's Air Markets Program Data shows that lower emission limits

[691] *Id.*; *see also* Annual Energy Outlook 2019 Reference Case Projection Tables, U.S. ENERGY INFORMATION ADMINISTRATION, Table 9, https://www.eia.gov/outlooks/aeo/tables_ref.php (projecting only 23 GW of cumulative new combustion turbine capacity additions compared to 116 GW of cumulative new combined cycle capacity additions through 2030).
[692] U.S. Energy Information Administration, ANNUAL ENERGY OUTLOOK 2019 WITH PROJECTIONS TO 2050 111 (Jan. 24, 2019).
[693] Proposal, 83 Fed. Reg. at 65,461.
[694] *See Honeywell International, Inc. v. EPA*, 372 F.3d 441, 445 (D.C. Cir. 2004) (A proposal must "provide sufficient factual detail and rationale for the rule to permit interested parties to comment meaningfully.")
[695] 2015 Final Rule.

for NGCC units are readily achievable.[696] According to Andover, for the top 10% of NGCC units operating over the past ten years, the average 99% confidence emission rate (only 1% chance that the rate is exceeded) was 830 lb/MWh and the median was 821 lb/MWh.[697] Using data for new NGCC plants installed between 2015 to 2018, Andover found an average emission rate of 809 lb/MWh and a 99% confidence rate of 918 lb/MWh, inclusive of NGCC operation in simple-cycle mode.[698] Andover's analysis demonstrates that an NSPS emission rate for NGCC units below 900 lb CO_2/MWh-gross is readily achievable using current technology under a wide range of operating conditions.[699] If EPA chooses to move forward with revisions for this source category, the agency must reopen the NSPS for NGCC based on new data and repropose the rule to allow for public comment.

G. EPA's Proposal to Deem Certain Uses of Carbon as Equivalent to Sequestration is Arbitrary and Capricious

The Proposal suggests amending the compliance requirements for the 2015 Final Rule in a way that could undermine the environmental integrity of subpart TTTT, and allow for arbitrary and inconsistent decision-making regarding what forms of carbon sequestration will be deemed satisfactory for compliance. In order for a source that is using carbon capture to demonstrate compliance with the current standards of performance under subpart TTT, the 2015 Final Rule requires that "captured CO_2 be geologically sequestered or stored in a different manner that is as effective as geologic sequestration."[700] The Proposal notes that this common-sense requirement would preclude captured CO_2 that is utilized in the food industry from qualifying as an emission reduction under subpart TTTT, because CO_2 used in the food industry "results in near term releases rather than in permanent sequestration."[701] The Proposal further argues that such uses of CO_2 would have "life cycle" benefits and suggests that such uses should qualify for compliance with subpart TTTT where an owner or operator demonstrates that "the CO2 will be used as an input to an industrial process where the life cycle emissions are reducing emissions as effective as geologic sequestration [*sic*]."[702]

Although carbon capture and utilization is a promising technology for reducing carbon pollution, EPA must ensure that any carbon capture and utilization system used to comply with a regulatory greenhouse gas standard achieve *permanent* reductions in emissions *on net* (equivalent in certainty and duration to geologic sequestration). Indeed, a standard of performance that does not ensure that captured CO_2 is permanently removed from the atmosphere on a net basis could end up partially or wholly negating the climate benefits associated with the initial capture of the CO_2, defeating the purpose of the standard. Because such a standard would also allow greater emissions of CO_2 than geologic sequestration, it would

[696] Andover Technology Partners, NATURAL GAS COMBINED CYCLE NEW SOURCE PERFORMANCE STANDARDS (Feb. 28, 2019).
[697] *Id*. at 1.
[698] *Id*. at 1, 10.
[699] *Id*.
[700] Proposal, 83 Fed. Reg. at 65,460.
[701] *Id.*
[702] *Id.*

also fail to "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction," as section 111(a) requires.[703]

Yet the Proposal fails to require that carbon capture and utilization systems achieve permanent reduction on a net basis, instead suggesting only a vague condition that "life cycle emissions" from a carbon utilization system "reduc[e] emissions as effective[ly] as geologic sequestration." The Proposal provides no guidance as to what minimum duration or certainty any level of life cycle emissions benefit would have to achieve in order for a utilization system to be deemed "as effective as geologic sequestration." Given that different pathways for utilizing CO_2 have very different levels of certainty and time horizons, the Proposal's failure to define how this comparison will be made renders it clearly arbitrary.

Equally concerning, the Proposal fails to provide any definition for "life cycle emissions" or guidance as to how "life cycle emissions" for a given carbon utilization system should be calculated. This omission is manifestly arbitrary given that life cycle assessment for carbon utilization systems is a relatively new field with well-documented methodological and data challenges.[704] A recent report by the National Academies of Sciences, Engineering, and Medicine detailed a number of methodological issues that must be carefully considered and disclosed in crafting life cycle assessments for captured carbon, including defining the system boundaries for the analysis; defining functional units; identifying and allocating emissions associated with co-products; quantifying uncertainties; and defining the time horizon for the study.[705] As a result, it is not even clear whether the Proposal contemplates that "life cycle emissions" would be calculated on a net basis—i.e., taking into account not just the gross utilization of captured carbon in a process, but also the broader indirect greenhouse gas impacts associated with product displacement and market effects.

As another recent academic report noted, the methods used for life cycle analysis "are currently lacking standardization in academia and industry across most CO_2 utilization fields… . Hence, 'apples-to-apples' comparisons of different technologies remain difficult."[706] Although various efforts have been undertaken to provide guidelines for life cycle assessment of carbon capture utilization technologies,[707] these guidelines are new and it is not clear how well they address the multiple methodological issues described above. Nor does the Proposal reference such guidelines or explain which (if any) would be satisfactory for purposes of subpart TTTT, and why.

[703] 42 U.S.C. § 7411(a).
[704] *See* National Academies of Sciences, Engineering, and Medicine, GASEOUS CARBON WASTE STREAMS UTILIZATION: STATUS AND RESEARCH NEEDS 167-68 (2019) (noting that few life cycle analyses of captured carbon existed as of 2013 and that "there are multiple methodological considerations and details in the application of LCA to carbon utilization technologies that must be carefully addressed if LCA is to provide a consistent and transparent framework for evaluating carbon utilization technologies.").
[705] *Id.* at 168-176.
[706] Arno Zimmerman et al., Techno-Economic Assessment and Life Cycle Assessment Guidelines for CO_2 Utilization 6 (Aug. 2018), https://deepblue.lib.umich.edu/handle/2027.42/145436.
[707] *See, e.g.*, IEA Greenhouse Gas R&D Programme, GREENHOUSE GAS EMISSIONS ACCOUNTING FOR CO_2 CAPTURE AND UTILISATION TECHNOLOGIES (Mar. 2018).

The Proposal fails to acknowledge these methodological issues, much less attempt to resolve them. And as noted above, the Proposal fails to even explain how the results of a life cycle emissions analysis would be compared to geologic sequestration, or what it would mean for life cycle emissions benefits to be as "effective as geologic sequestration." Because this element of the Proposal "fails to consider an important aspect of the problem" or "examine the relevant data and articulate . . . a rational connection between the facts found and the choice made,"[708] it is clearly arbitrary and capricious. Moreover, these gaps in the Proposal are so glaring and fundamental that EPA cannot rectify them in a final rule without first providing the public an opportunity to provide comment.[709]

H. EPA Proposed Changes to Applicability Determinations Are Arbitrary and Capricious

EPA's proposal to allow for case-by-case determinations of design efficiency when determining the applicability of subpart TTTT arbitrarily fails to assure that such determinations will be made in a rigorous and transparent manner. The Proposal includes several changes to the applicability provisions of subpart TTTT, one of which would affect the calculation of EGU design efficiency that is used to determine the electric sales applicability threshold and is relevant to both new and existing EGUs.[710] The current rule allows the use of three specific methods for determining design efficiency.[711] According to EPA, since 2015, the agency has become aware that owners or operators of certain existing EGUs—many of which are CHP units—do not have records of the original design efficiency and are therefore unable to readily determine if they meet the applicability criteria.[712] As a result, the Proposal would amend the definition of design efficiency to allow the Administrator to approve alternative methods to determine design efficiency.[713]

EPA's proposal would grant the Administrator broad discretion to make case-by-case determinations on alternative methods to determine design efficiency. Moreover, the Proposal does not provide any mechanisms—such as an opportunity for public notice and comment, or public disclosure—to assure the public that these determinations are made on a well-reasoned basis and in a consistent manner. If EPA finalizes the proposed changes to the applicability provisions, it must at minimum require applicants to demonstrate why the standard method for determining design efficiency in subpart TTTT cannot be used; require the agency to provide public notice of any applications for a case-by-case determination of design efficiency, and an opportunity for comment; and provide for public disclosure of final determinations and the basis

[708] *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983).
[709] *Cf. Int'l Union, UMW v. MSHA*, 407 F.3d 1250, 1260 (D.C. Cir. 2005) ("While an agency may promulgate final rules that differ from the proposed rule . . . a final rule is a 'logical outgrowth' of a proposed rule only if interested parties should have anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period. The 'logical outgrowth' doctrine does not extend to a final rule that is a brand new rule, since something is not a logical outgrowth of nothing, nor does it apply where interested parties would have had to divine the Agency's unspoken thoughts, because the final rule was surprisingly distant from the proposed rule.").
[710] Proposal, 83 Fed. Reg. at 65,434-35.
[711] *See id*. at 65,463 (Subpart TTTT currently lists ASME PTC 22 Gas Turbines, ASME PTC 46 Overall Plant Performance, and ISO 2314 Gas turbines – acceptance tests as approved methods to determine design efficiency).
[712] *Id.* at 65,435.
[713] *Id.*

for those determinations. Without such safeguards, EPA's proposed changes would allow the agency to arbitrarily approve inadequate or inconsistent approaches to computing design efficiency—and potentially exempt certain EGUs from subpart TTTT—without any notice to the public or any accountability for the agency or EGUs.

Attachment 1

Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

New Source Performance Standards for coal steam EGUs

Contract C-19-EDF-01 coal steam
to:

Environmental Defense Fund
257 Park Avenue South
New York, New York 10010
Phone (212) 505-2100

February 28, 2019

James E. Staudt

Andover Technology Partners
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Contents

Executive Summary

In December 2018 the Environmental Protection Agency (EPA) proposed to revise the New Source Performance Standards (NSPS) for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants. EPA is proposing that for newly constructed fossil steam Electric Generating Units (EGUs) and Integrated Gasification Combined Cycles (IGCCs), the Best System of Emission Reduction (BSER) would be the most efficient demonstrated steam cycle (supercritical steam conditions for large EGUs and best available subcritical steam conditions for small EGUs) in combination with the best operating practices. Based on that, EPA has proposed the following emission standards (based on a 12-operating month rolling average):

- 1,900 lb CO_2/MWh-gross for sources with heat input > 2,000 MMBtu/h
- 2,000 lb CO_2/MWh-gross for sources with heat input <= 2,000 MMBtu/h
- 2,200 lb CO_2/MWh-gross for coal refuse-fired sources

A 2,000 MMBtu/h steam generator has a capacity of roughly 200 MW.

Having examined CO_2 emission rates for new, uncontrolled (no CO_2 capture) coal electric generating units using information on coal technologies and data on coal units currently in operation, including coal units located outside the U.S., as well as a review of EPA's development of the BSER it is my opinion that EPA's NSPS emissions rates are insufficiently stringent and can be improved.

Rather than basing the NSPS on supercritical or ultrasupercritical steam generation technology, for all of the situations that are reasonably expected to occur EPA's BSER is achievable with subcritical steam technology that has been available for over 50 years. This is because EPA's BSER emission rate was determined by the combination of two extremely rare situations - air cooling and dried lignite fuel that have never been used together - when the vast majority of coal facilities use bituminous or subbituminous fuel and recirculation cooling.

By determining BSER in this manner, EPA's own analysis shows that for bituminous and subbituminous fuels the NSPS limits are readily possible with subcritical steam conditions at a 99.5%[1] confidence rate.

Thus, the proposed NSPS rates are not consistent with EPA's statement that supercritical and ultrasupercritical technology form the basis of this rule. Simply put, they do not.

[1] EPA's analysis incorrectly used a methodology that results in 99.5% confidence versus their stated 99% confidence.

There are only 14 lignite units listed in the 2017 U.S. Energy Information Administration (EIA) Form 860 and only 9 are larger than 100 MW (8 are larger than 200 MW). There are only three pulverized coal EGUs with dry cooling – all in Gillette, WY. In addition, one coal-refuse unit had air cooling. There are no facilities, and there likely will never be any facilities, that are both lignite fired and have dry cooling. For each of these lignite or air cooled units the location of the plant was determined by the location of the fuel. This is out of 495 coal-fired EGUs listed in 2017 EIA Form 860. Because of the unique qualities of lignite – the extremely low heating value, its geographic limitations and severe penalty on heat rate – it is not reasonable to use it as a basis for a nationwide standard. Air cooling is even rarer, and all three pulverized coal units with air cooling fit within a circle with a four mile radius located adjacent to coal mines in a remote and arid region.

By having these rare conditions – and more importantly, a *combination* of these rare conditions - determine the NSPS rate, EPA has created an NSPS rate that is barely better than the fleet rate in the United States – a fleet that is 60% subcritical - and falls short of the average *fleet* rates in the European Union, China and particularly Japan. This is not a New Source Performance Standard. For bituminous and subbituminous boilers it can readily be met with subcritical boiler technology that was available 50 years ago.

The small unit limit assumes subcritical boiler operation, although there is no technical reason that supercritical conditions cannot be achieved on a small boiler. While small boilers may be somewhat less efficient than large boilers on a net output basis, they can be built to be supercritical and meet a far better rate than the one proposed.

For coal refuse boilers EPA proposes a rate with little justification. Coal refuse boilers are universally Circulating Fluidized Bed (CFB) fired. EPA has data on CFB fired coal boilers as well as coal refuse boilers but did not use it for determination of the coal-refuse limit. This data and coal CFB boiler emissions data suggests that EPA's NSPS for waste fuel boilers is too weak.

Recommendation regarding NSPS Emission Rates:

The approach used by EPA in developing its NSPS rate, normalizing for two extremely rare circumstances that are not found together at any power plant in the United States results in NSPS standards that are far too weak. There is no technical reason that the small unit standard should not also be based upon supercritical technology – thus there should not be a distinction between large and small units. EPA's coal refuse standard is also too weak and was developed without a realistic analysis. It should be based upon supercritical circulating fluidized bed (CFB) technology.

If EPA proceeds to develop standards based on efficient operation of a conventional steam EGU, I recommend that EPA develop rates that:

- Reflect use of modern supercritical and ultrasupercritical technology rather than rates achievable with decades-old technology for the most common applications,
- Are not based upon extremely rare situations that are not found in combination anywhere in the United States and likely nowhere on earth
- Recognize that there is no technical reason why a small boiler cannot use supercritical boiler technology.
- Base the coal refuse emission standard, to the extent such a standard is considered, upon an analysis of a proper comparable boiler technology

Program Results

I. Background on EPA's NSPS

In the NSPS EPA has proposed that for newly constructed fossil steam EGUs the BSER would be what the agency characterizes as the most efficient demonstrated steam cycle (supercritical steam conditions for large EGUs and best available subcritical steam conditions for small EGUs) in combination with the best operating practices. EPA has proposed the following emission standards (based on a 12-operating month rolling average) as the Best System of Emission Reduction (BSER):

- 1,900 lb CO_2/MWh-gross for sources with heat input > 2,000 MMBtu/h
- 2,000 lb CO_2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h
- 2,200 lb CO_2/MWh-gross for coal refuse-fired sources

Factored into these emission rates are the impacts of capacity factor, ambient temperature and use of dry cooling as EPA determined them. The following sections will evaluate the emission standards that are proposed, the factors that EPA considered in formulating emission rates, and make recommendations regarding BSER.

In evaluating BSER, EPA collected data on the lowest CO_2 emitters using data collected by the plant Continuous Emission Monitoring System (CEMS) and submitted to EPA. EPA ranked these facilities from lowest to highest emitters by the highest rate over a ten-year period. EPA then normalized emission rates accounting for design factors, such as steam temperature, pressure, number of reheats, type of cooling and others as well as the non-design factor of ambient temperature to identify those EGUs with the lowest normalized emission rates. After normalizing for these factors, Weston unit 4 was determined to be the lowest emitting large unit and Wygen III was determined to be the lowest emitting small unit. These factors were used by EPA to develop estimates of reasonable emission rates (99% confidence rates) for different configurations. Essentially, these are rates that EPA believes a new EGU can meet with 99% certainty. These are shown in**Error! Not a valid bookmark self-reference.** Tables, 1, 2 and 3.

Table 1. Summary of Demonstrated Technologies for Large EGUs, Cooling Tower[2]

Emissions standard (lb CO_2/MWh-gross) 3 significant figures	Demonstrated by Technologies & Fuel
1,600	Bituminous Advanced ultra-supercritical I
1,700	Bituminous supercritical Subbituminous & dried lignite Advanced ultra-supercritical I
1,800	Bituminous subcritical Subbituminous supercritical Dried lignite & petroleum coke ultra-supercritical Lignite advanced ultra-supercritical I
1,900	Subbituminous, dried lignite, petroleum coke, & lignite subcritical Coal refuse advanced ultra-supercritical I

Table 2. Summary of Demonstrated Technologies for Large EGUs, Dry Cooling [3]

Emissions standard (lb CO_2/MWh-gross) 3 significant figures	Demonstrated by Technologies & Fuel
1,600	-
1,700	Bituminous advanced ultra-supercritical I
1,800	Bituminous supercritical Subbituminous, dried lignite, & petroleum coke advanced ultra-supercritical I
1,900	Bituminous subcritical Subbituminous, dried lignite, & petroleum coke ultra-supercritical Lignite advanced ultra-supercritical I

Table 3. Summary of Demonstrated Technologies for Small EGUs [4]

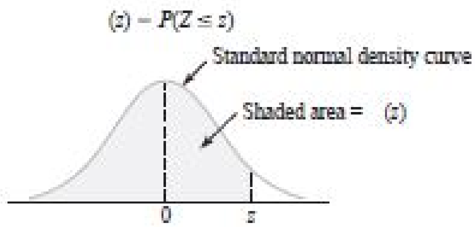
Emission standard (lb CO_2/MWh_{gross})	Demonstrated by Technologies & Fuel
1,800	Bituminous best subcritical + dry cooling Bituminous standard subcritical + cooling tower
1,900	Bituminous standard subcritical + dry cooling Subbituminous best subcritical + dry cooling Subbituminous standard subcritical + cooling tower Dried lignite, petroleum coke, and lignite standard subcritical + cooling tower
2,000	Subbituminous standard subcritical + dry cooling Dried lignite, petroleum coke, and lignite standard subcritical + dry cooling Coal refuse best subcritical + cooling tower (no compliance margin)
2,100	Coal refuse best subcritical + dry cooling (no compliance margin) Coal refuse standard subcritical + cooling tower
2,200	Coal refuse standard subcritical + dry cooling (with compliance margin)

In determining the 99% confidence level emissions rate, EPA took the average emission rate and added the standard deviation times 2.57.[5] This is, in fact, incorrect. In a normal density curve, shown in Figure 1, to be certain that the emission rate is below the limit 99% of the time, the multiple of the standard deviation should be selected so as to ensure that the shaded portion of the figure equals 0.99. That occurs when $z = 2.33$. When $z=2.57$ the shaded portion of the curve is equal to 0.995. We are only concerned about emissions *exceeding* the NSPS limit, not if the emissions are too low. So, $z=2.33$ is the correct value of z to use if it was EPA's intent to

[2] Memo from The Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency to EGU NSPS Docket (EPA-HQ-OAR-2013-0495), on subject Best System of Emissions Reduction (BSER) for Steam Generating Units and Integrated Gasification Combined Cycle (IGCC) Facilities, December 2018
[3] Ibid
[4] Ibid
[5] Ibid, page 9. However, in the spreadsheet provided by EPA, they used 2.58.

determine an NSPS limit at a 99% confidence level. Correcting this error to reflect a 99% confidence level will have the effect of lowering each of the emission rates shown in Tables 1 through 3 somewhat.

Figure 1. Normal Distribution Curve



Another apparent error was found in EPA's analysis. EPA states in Figure 8 of the December 2018 memo that Weston 4 had a 99% confidence emission rate of 1770 lb/MWh (actually, 1767 lb/MWh using EPA's incorrect z value of 2.58)[6], but in examining EPA's spreadsheet[7] Cliffside 6 actually appears to have that 99% confidence rate (incorrectly calculated with z=2.58 rather than 2.33). At z = 2.33 the 99% confidence rate for Cliffside 6 is 1761 lb/MWh.[8] So, because the standard deviation for Cliffside 6 is only 25 lb/MWh, it is the lowest emitter. Weston 4 had a similar average annual emission rate, but had a higher standard deviation. If these values are used to determine the NSPS, it is clear that a lower emission standard can be justified than what EPA proposed for large EGUs.

II. Steam Generation Technology – Large Boilers

According to EPA's proposal, EPA's NSPS for large coal boilers (over 2,000 MMBtu/hr in size, or about 200 MW) of 1,900 lb/MWh-gross is based upon use of ultrasupercritical (USC) or supercritical (SC) steam generation technology, although the NSPS does not expressly require this technology.[9] The distinction between USC and SC is that, while both methods operate at steam temperatures and pressures greater than the critical point for water, USC operates at higher temperatures and pressures. These higher temperatures and pressures permit a greater portion of energy to be extracted from the steam turbine from the additional energy needed to achieve the higher temperature and pressure, which improves efficiency. These higher temperatures and pressures were not possible in the past because the available metals for constructing steam

[6] Coal_EGU_Annual_Emissin_Rates.xls
[7] Ibid
[8] Coal_EGU_Annual_Emissin_Rates_JES.xls
[9] NSPS Proposal at page 91

generators and steam turbines were not capable of reliably handling such high temperatures and pressures; however, today they are possible as a result of improvements in metallurgy and, as will be shown, this is the common approach used in other nations for new coal fired power plants. A previous study of different facilities, some existing SC units, newer SC units, and some newer USC units compared performance of these units. A comparison of the steam temperatures and pressures of the studied units is shown in Figure 2. NETL BIT and NETL SUB USC are model plants evaluated in the United States Department of Energy's National Energy Technology Laboratory and are not operating units, but comprehensive engineering studies. As the figure shows, the highest temperatures and pressures of operating USC units are for overseas units. There is only one USC unit in the United States, John Turk plant.

Figure 2. Superheater temperature and pressure of units examined in Ref. [10]

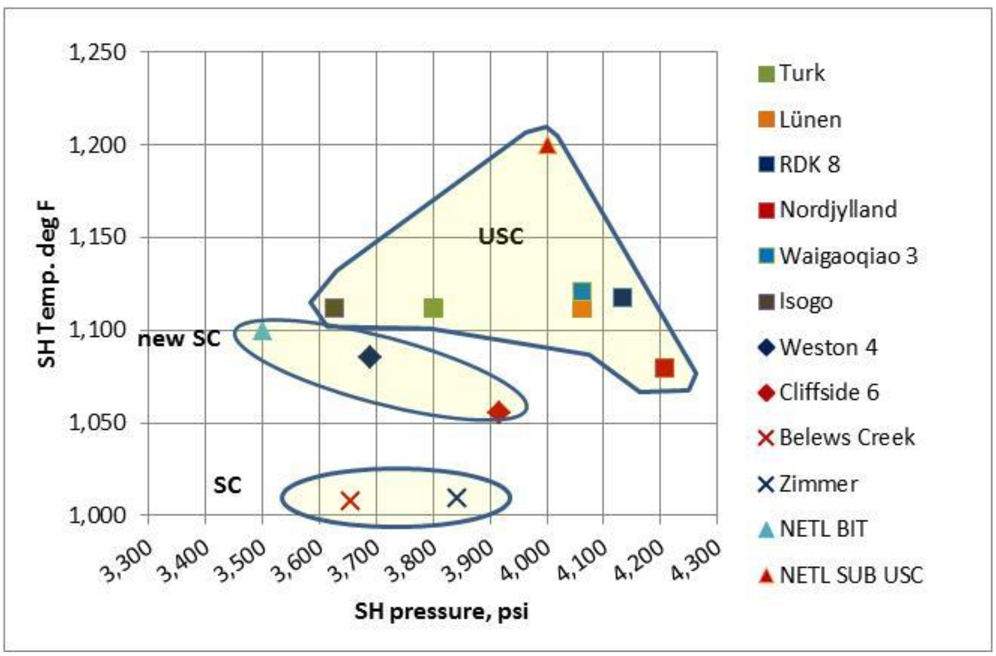
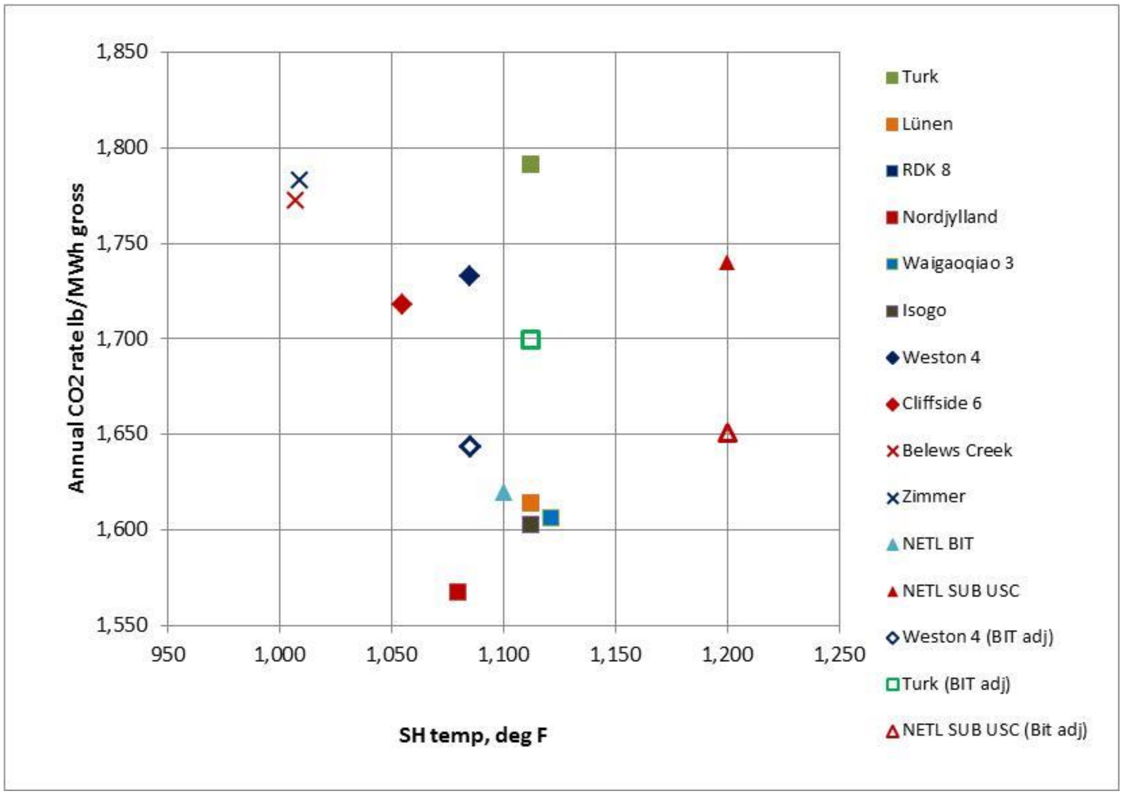


Figure 3 shows the estimated annual CO_2 emissions versus steam temperature for the plants that are in Figure 2. As shown, the lowest CO_2 emitter is Nordjylland. That unit is USC and has a high superheater pressure. It is also the sole once-through cooling unit, which improves performance. All of the other units use a recirculating cooling system with cooling towers, which means that the thermal exhaust is ultimately sent to the air. Recirculating cooling is by far the most common cooling method used in new coal-fired power plants.

[10] Andover Technology Partners, "Uncontrolled CO_2 Emission Rates From Selected Electric Generating Units", prepared for Environmental Defense Fund, August 26, 2016

Figure 3 Estimated Annual CO_2 Emission Rate versus superheater temperature.

US units calculated from US EPA Air Markets Program Data- average of 2014 and 2015 annual rate. For overseas units rate is estimated from reported efficiency data and assumed coal CO_2 emission rate.



A study by the International Energy Agency Clean Coal Center published average national fleet efficiencies (net, LHV basis)[11] and percentages of those national fleets that are USC or SC technology. As shown in Table 4, as of March 2016 over 60% of US capacity was subcritical. This has likely changed somewhat in the past few years with small unit retirements. Nevertheless, the United States lags behind other nations in deployment of USC technology, and it is reflected in the lower average fleet efficiencies. This is very significant, since, for a given fuel, efficiency is inversely related to the CO_2 emissions rate. Figure 4 shows the emissions rate (lb/MWh-gross) that is estimated for different efficiencies (net, LHV) for bituminous and for subbituminous coal. As shown, the Japanese fleet average is only about 1700 lb/MWh-gross since it burns mainly bituminous coal. On the other hand, the US fleet has emissions on the order of 1900-2000 lb/MWh-gross. This figure also demonstrates that bituminous coal units are capable of lower emissions rates than subbituminous units at any given efficiency level.

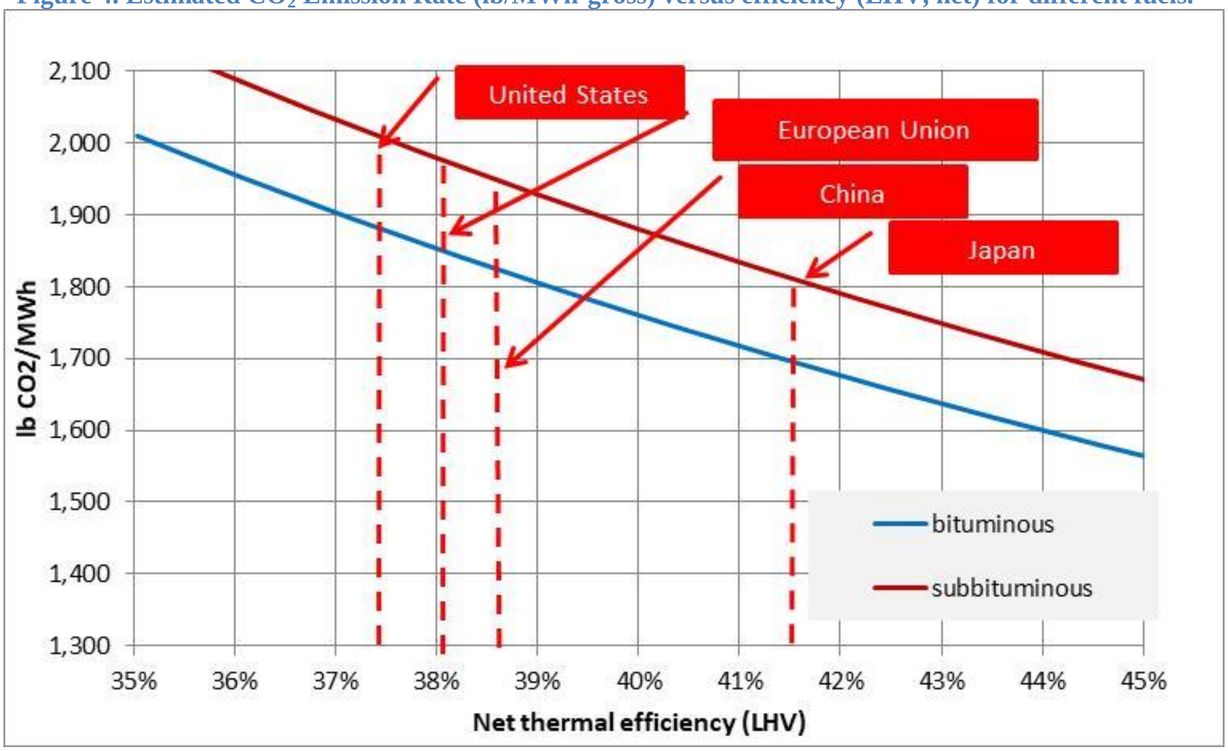
[11] Efficiencies can be represented on the basis of net power output or gross power output and also on the basis of heat input expressed in fuel higher heating value (HHV) or fuel lower heating value (LHV). These are explained in more detail in Andover Technology Partners, "Uncontrolled CO_2 Emission Rates From Selected Electric Generating Units", prepared for Environmental Defense Fund, August 26, 2016.

What this data demonstrates is that the proposed NSPS for large units is only modestly better than what the US fleet currently achieves on average, is less stringent than the average in China and is well short of what is average for Japan. Therefore, other nations are a model for the United States, and EPA's proposed NSPS will not be a model for other nations. In fact, EPA determined that the large boiler standard is only 2% lower than the average of all coal-fired generators built since 2010 – not all of which are supercritical and none of which are subject to a CO_2 standard.[12]

Table 4. Average Fleet Efficiency and Percent USC and SC by capacity.[13]

	Avg. Efficiency (net, LHV)	Percent USC	Percent SC
Japan	41.6%	57%	38%
China	38.6%	20%	29%
European Union	38%	17%	15%
United States	37.4%	<1%	37%

Figure 4. Estimated CO_2 Emission Rate (lb/MWh-gross) versus efficiency (LHV, net) for different fuels.[14]



As demonstrated in EPA's analysis, the large unit limit is not actually based upon supercritical or ultrasupercritical technology for the most common fuels and boiler configuration.

[12] NSPS proposal at page 84

[13] IEA Clean Coal Center, "An overview of HELE technology deployment in the coal power plant fleets of China, EU, Japan and USA", CCC/273, December 2016

[14] Andover Technology Partners, "Uncontrolled CO_2 Emission Rates From Selected Electric Generating Units", prepared for Environmental Defense Fund, August 26, 2016, efficiency values for the United States, Japan, China and the European Union are overlayed.

For bituminous or subbituminous fuels, it is based upon subcritical steam technology and dry cooling – not exactly what one would regard as state of the art for pulverized coal units. This is because EPA decided that the combination of dried lignite and dry cooling must be accommodated. As will be described in more detail later, EPA chose to base a standard upon a combination of situations that individually are extremely rare and *have never been done in combination*. As a result, the standard that EPA has proposed is much less stringent than what can be achieved using state-of-the-art steam plant technology that is common outside the United States, the most common fuels, and the most common cooling technologies for new units.

III. Steam Generation Technology - Small Units

EPA determined that the lowest emitting units were Miami Fort 6 (operational in 1960), Mcmeekan 1 & 2 (both operational in 1958), and Yorktown 1 & 2 (operational in 1957 and 1959, respectively). Once normalized to dry cooling, ambient temperature of 20°F, and certain design factors, EPA determined that Wygen III (operational in 2010) was the lowest emitting small unit. EPA used dry cooling, dried lignite and subcritical steam conditions as determining NSPS although EPA recognized that subcritical bituminous fueled units could achieve an emission rate of 1,800 lb/MWh and subbituminous units 1,900 lb/MWh, as shown in Table 3. Therefore, the small EGU limit is artificially high because of the use of dry cooling in combination with dried lignite as determining NSPS, which is a combination of two very rare conditions that has never been used in combination and is very unlikely to ever be selected by a new project developer.

Small boilers (200 MW or less) have a median operation date of 1961 versus 1977 for larger units.[15] Therefore, the existing population of small units is very old and is not representative of what could be deployed in a new unit. EPA did not consider supercritical steam conditions for small boilers, even though there is no technical reason that supercritical steam conditions cannot be used at smaller facilities. In fact, the first supercritical steam boiler was Philo 6, which was built in 1957 with a capacity of 120 MW.[16] According to US DOE, a 550 MW subcritical pulverized coal power plant would cost $1,960/kW versus $2,026/kW for a supercritical plant, or only a 3.4% difference in capital cost. Fixed and variable operating costs are very close.[17] There is no reason to believe that the difference in cost for a smaller plant would

[15] Coal.xls

[16] ASME International, "Philo 6 Steam-Generating Unit – Designated a Historic Mechanical Engineering Landmark", August 7, 2003

[17] US Department of Technology National Energy Technology Laboratory, Cost and Performance Baseline for

be dramatically different. So, the difference in cost is modest. Small steam generators are generally uneconomical except in unusual situations. That is why so few small EGUs have been built in recent years. According to EIA Form 860, three conventional coal steam units between 25 and 200 MW have been placed in operation since 2000 while 22 units greater than 200 MW have been placed in operation in that time. The three 25-200 MW units are all mine-mouth plants (Wygen II, Wygen III and Spiritwood). The Wygen units are in a remote region of Wyoming, and located adjacent to PRB coal mines. Spiritwood is, in fact, a lignite fired cogeneration plant that provides steam to an ethanol plant in North Dakota.[18] With such low cost fuel and with one of the plants a cogeneration unit, efficiency is not as critical an issue at these plants as with a typical EGU. For example, EPA states that, "Wygen III has relatively low steam temperatures and pressures and does not have a reheat cycle."[19] Therefore, it is apparent that for Wygen III, efficiency was not a major concern in its design and that would explain the use of subcritical rather than supercritical conditions.

It is apparent that for small boilers there is no reason why supercritical boiler technology cannot be used and would not be economical, especially if a CO_2 standard made efficiency more important.

IV. Coal-Refuse Fired Facilities

The coal refuse limit is not addressed in the December 2018 memo on the BSER. It is discussed in the proposed rule which states that Wygen III data was normalized to develop the coal-refuse fired EGU limitation.[20]

CFBs are the current technology used for burning coal refuse. Wygen III is not a CFB. These coal refuse units are all located in the east – mainly in the Middle Atlantic States - where coal cleaning plants were once located. As a result, there is no reason to consider dried lignite as a possible fuel for coal refuse facilities.

I evaluated emissions of CFB, stoker and bubbling bed boilers used to burn coal or coal refuse for 2018 and for the ten years from 2009 to 2018. The coal refuse boilers are expected to emit on average 229 lb/MMBtu compared to 206 lb/MMBtu for bituminous coals, and there is no reason to expect the impact on efficiency to change because CFB boilers contain a significant

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Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3, July 6, 2015 , DOE/NETL-2015/1723, Table ES-4

[18] https://greatriverenergy.com/we-provide-electricity/making-electricity/spiritwood-station/

[19] NSPS Proposal page 96

[20] NSPS page 97

amount of sand and other ballast regardless of fuel.[21] Therefore, for any given efficiency, we would expect coal refuse boilers to emit roughly 10% more than bituminous fuel boilers.

None of the coal-refuse fired boilers reported generation, and therefore it is necessary to use coal-fired EGUs to determine what CFBs are capable of with regard to emissions on a lb/MWh gross basis. H L Spurlock was found to be the CFB facility with the lowest emission rate in lb/MWh at under 1,800 lb/MWh. Table 5 shows the four lowest emitting CFBs – at Spurlock (in Kentucky) and at Sandow Station (in Texas). Using the 99% confidence level emissions rate (with z=2.33), these are well below the emission rate EPA proposed. Because Sandow is in Texas and coal refuse plants are all located in cooler climates, such as Pennsylvania, it is reasonable to assume that a lower emission rate is possible in a cooler climate. Sandow is also lignite fired, which increases the emission rate. Spurlock 4 data suggests that an emission rate of 1,830 lb/MMBtu is reasonable. For dry cooling, a higher emission rate might result, perhaps around 1,930 lb/MMBtu. However, Spurlock 4 is bituminous coal-fired and adjusting for the higher emission rate per unit of heat input from coal-refuse a refuse fired unit would have roughly 10% higher emissions, or about 2,030 lb/MWh.

Table 5. Estimates of 99% confidence CO_2 emission rate for CFBs.[22]

Row Labels	Average of Gross Load (MW-h)	Average of CO_2 lb/MWh	StdDevp of CO_2 lb/MWh	99% confidence	Average of Heat Rate, Btu/kWh_g	Adj. 99% to coal refuse, lb/MWh
H L Spurlock_4	1,901,977	1,751	35	1,831	8,531	2,036
H L Spurlock_3	1,826,423	1,808	38	1,897	8,813	2,109
Sandow Station_5A	2,023,998	1,950	51	2,068	8,961	2,203
Sandow Station_5B	1,838,215	1,951	47	2,061	8,966	2,196

Although CFB boilers are most often subcritical, supercritical CFB boilers are being built internationally, where there is greater demand for coal boilers that burn low quality fuels.[23] The impact of supercritical CFB technology is that the emission rate would be roughly 100 lb/MWh lower. EPA's proposal does not recognize that CFB is the typical combustion technology for

[21] December 2018 memo at page 3
[22] Ibid
[23] https://www.ge.com/power/steam/boilers/circulating-fluidised-bed
https://www.powerengineeringint.com/articles/print/volume-16/issue-5/features/supercritical-cfb-boiler-technology-enters-utility-scale-territory.html
https://www.powermag.com/advanced-cfb-technology-gains-global-market-share/
Utt, J., Giglio, R., "Foster Wheeler's 660 MWe Supercritical CFBC Technology Provides Fuel Flexibility for Asian Power Markets", Presented at PowerGen Asia, Bangkok, Thailand, October 3-5, 2012

coal refuse. To the extent a separate standard for coal refuse units is considered, it should be based on supercritical CFB.

V. Specific Issues EPA Used to Adjust the Emissions Rate

EPA used a number of conditions to adjust, or "normalize" the emissions rate. Other than the adjustment factor used, the details of how these are developed are not provided. In any event, it is my opinion that normalizing to some of these situations artificially raises the NSPS rate to well above what is achievable for the vast majority of coal-fired boiler cases.

Dry Cooling

The ability to reject heat is important to any thermal power plant but it is especially important for steam power plants. Heat rejection is a key determinant of steam turbine vacuum and how much power can be extracted from a steam turbine. Cooling with water is so much more effective than air that the use of air cooling on a coal steam plant is extremely rare. This is why so many coal-fired plants are located near natural or man-made bodies of water.

EPA could identify only four coal-fired facilities in the entire United States that use dry cooling. These can be identified using EIA Form 860 data. Three of them – Wyodak (402 MW), Wygen III (116 MW) and Dry Fork Station (485 MW) – are located near one another in Wyoming. One – Virginia City Hybrid Energy Center (two units 334 MW each) – is in Virginia. According to EIA Form 860 the three plants in Wyoming are all wall-fired boilers and therefore use pulverized coal. The Wyoming coal units are located adjacent to PRB coal mines in a very arid and remote region of the United States. It is apparent using satellite images (Google Earth) that the closest significant body of water, the Keyhole Reservoir (which is a small reservoir), is well over 20 miles away. From Google Earth satellite images, there appear to be ash ponds and a small lake or pond (less than a half mile across) to the west of the plants – the only apparent water in the region. As shown in Figure 5, Wyodak and Wygen III are adjacent to one another and are within about 8 miles (measured using ruler from Google Earth) from Dry Fork station near Gillette, WY (altitude roughly 4,600 feet) – demonstrating that this is a unique situation, and something that is very unusual in the United States.

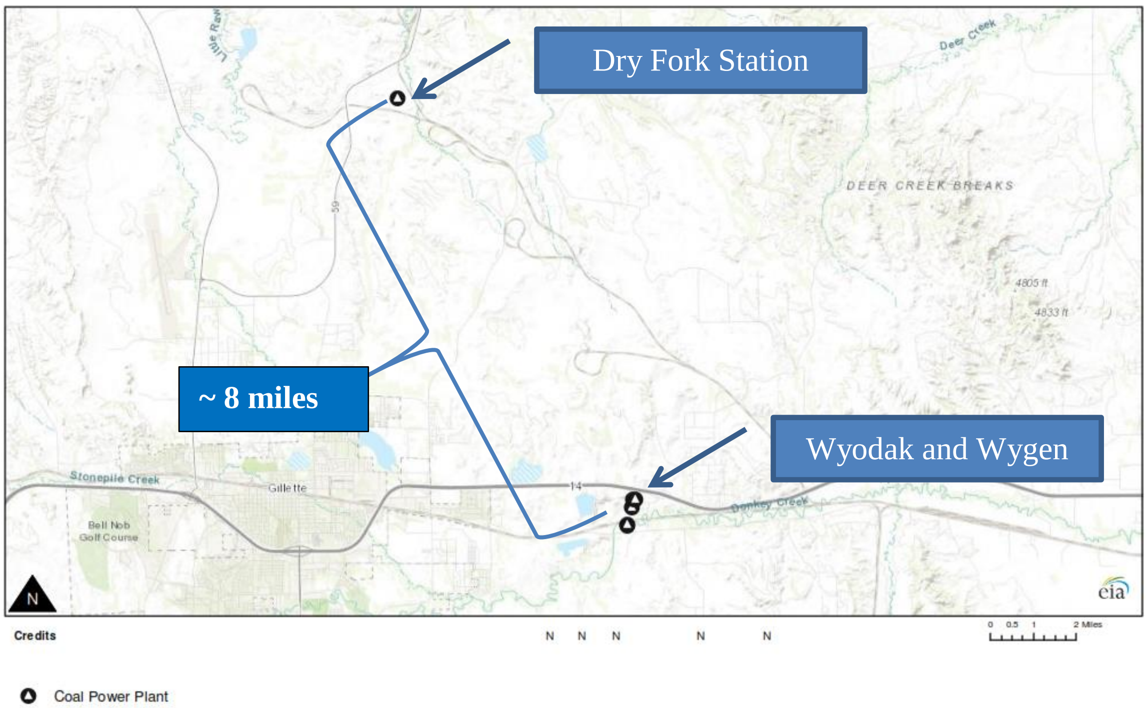
According to EIA Form 860 and Dominion Energy's web site[24] the Virginia plant uses fluidized bed technology and burns waste coal and wood waste (up to 20% biomass). It is therefore located near those fuel sources (including a site of waste or "gob" coal) and, using Google Earth satellite imagery, is just over one mile from the Clinch River. EPA acknowledged

[24] https://www.dominionenergy.com/about-us/making-energy/coal-and-oil/virginia-city-hybrid-energy-center

in the NSPS that waste coal boilers are located near coal refuse piles: "coal refuse-fired EGUs tend to be located close to existing coal refuse piles".[25] Moreover, it falls into a different subcategory than boilers that fire only coal.

In each of these four EGUs, the location of the plant was determined by proximity to the fuel. In the case of Virginia Hybrid Energy Center, its location could have been easily changed to near the Clinch River had the proximity of the fuel not been so important.

Figure 5. Location of Dry Fork, Wyodak and Wygen power plants near Gillette, WY[26]



These four plants are well outside the norm of coal EGUs – three being mine-mouth plants located near one another in an arid, high-altitude region and another that burns adjacent waste coal and wood waste. In fact, these four plants are very unique (fewer than 1% of the coal units in the US are air cooled). Newer coal plants, such as Cliffside 6, Turk, Longview, Weston 4, etc., utilize a recirculating cooling system with some form of heat exhaust to the air (induced draft or forced draft cooling of the recirculating water).

It is clear that the four plants cited by EPA are outliers, and for good reason.

Although dry cooling is more commonly applied to Natural Gas Combined Cycle (NGCC) plants throughout the country, it is far from the norm. EPA acknowledges that:

[25] NSPS at 90

[26] From Energy Information Administration Energy Maps

"For example, combined cycle units use much less cooling water, because significantly less heat energy remains that is required to be removed by cooling at the outlet of the steam turbine of a combined cycle unit compared to a coal-fired EGU of the same capacity."[27]

Nevertheless, EPA acknowledges that only about 15% of NGCC capacity uses dry cooling. Therefore, the use of dry cooling on NGCC plants is not an indication of usefulness on coal steam plants because EPA acknowledges that technically they are very different and because, despite the more favorable conditions for use of dry cooling at NGCC plants, dry cooling is still relatively uncommon.

It is clear that dry cooling is so rarely used by coal-fired power plants and has only been used under very unique circumstances that it should not form the basis of the NSPS for coal-fired plants.

Dried Lignite

Lignite is only used at a handful of mine mouth plants because it is not available in most of the United States and it is such a low quality fuel that it is not economical to transport. There have been recent efforts to incorporate drying to improve the heat rate when using lignite[28, 29] and EPA has assumed dried lignite as the basis for NSPS. Lignite is so rarely used as a fuel, and perhaps might never be used in a new coal power plant, it is therefore unreasonable to make this the basis of an NSPS for bituminous and subbituminous fuel, which are far more widely used and are capable of much lower CO_2 emission rates.

Air Cooling and Dried Lignite

EPA's proposed NSPS is based upon a combination of air cooling and dried lignite. No such plant exists or will likely exist. Each of these individually is an extremely rare situation and in combination does not exist. As a result, the NSPS proposed by EPA is based upon an unrealistic set of assumptions that has the effect of increasing the proposed rate.

Petroleum Coke

Petroleum Coke is not used in large quantities in large pulverized coal utility boilers because the fuel is limited in supply to what nearby refineries produce and because petroleum coke is high in sulfur content. For example, at the Monroe plant in Michigan, in 2017 it

[27] NSPS at 92-93

[28] https://www.energy.gov/fe/articles/innovative-drying-technology-extracts-more-energy-high-moisture https://www.powermag.com/lignite-drying-new-coal-drying-technology-promises-higher-efficiency-plus-lower-costs-and-emissions/

[29] "Lignite Drying: New Coal-Drying Technology Promises Higher Efficiency Plus Lower Costs and Emissions", *Power Magazine*, July 1, 2007, available at: https://www.powermag.com/lignite-drying-new-coal-drying-technology-promises-higher-efficiency-plus-lower-costs-and-emissions/

comprised only about 5% of the total thermal input.[30] For those situations where it is a large portion of the total fuel, it is typically burned in smaller units, and in circulating fluid bed boilers which are often smaller and remove the sulfur in the bed.

Capacity Factor –

It is acknowledged that power plants are typically less efficient at low loads than at full loads. Moreover, coal-fired power plants are far more costly in terms of capital cost than natural gas fired plants. New coal-fired plants will therefore only be developed in situations where a high capacity factor is expected. Therefore, there is not a need to normalize for capacity factor. EPA's analysis of hourly data from Weston 4, Spurlock 4, Turk and Wygen III emissions versus capacity factor and operating time versus capacity factor (see charts 1 and 2 of associated excel files provided with EPA memo on BSER) demonstrate that these units operate primarily at a capacity factor that is associated with the lowest emissions rate, and these units are not subject to any CO_2 limitation and therefore are not designed or operated to minimize CO_2 emissions. Design options are possible for improving efficiency at part load include sliding pressure operation, and this is not accounted for since this is generally not used due to the expense and design concerns.[31] It is unclear how EPA used capacity factor to normalize the emission rate for the lowest emitting unit. That information was not provided.

[30] See Coal.xls tab Monroe

[31] Vitalis, Brian P., "Constant and sliding-pressue options for new supercritical plants", *Power Magazine*, 12/15/2006

VI. Recommendations for Emission Rates

Because EPA based its emission rates for all coal units on extremely rare situations that are very location-specific, may never be encountered with a new plant in the future, yet have the effect of increasing the NSPS rate substantially, the effect is that the NSPS rates that EPA is proposing is far too weak and can be improved substantially. I recommend that EPA develop more stringent rates that reflect conditions that are actually likely to be encountered rather than basing the NSPS on a combination of rare circumstances that does not exist in the United States and perhaps do not exist anywhere on earth. For example, EPA's own analysis showed that 1,700 lb/MWh_g is achievable at a high degree of certainty for the situation of a bituminous fired supercritical boiler with recirculation cooling, which is a situation that actually exists. Furthermore, EPA provides no justification for not applying supercritical boiler technology to the small unit limit, although there is no technical reason why supercritical boiler technology cannot be used for small electric utility boilers. There should not be a distinction between small and large boilers.

For coal refuse fired boilers, EPA should have used a more appropriate analysis, which would have resulted in a more stringent limit. To the extent that there is a separate limit for coal refuse fired boilers, it should be a lower emission rate than EPA is proposing.

Attachment 2

Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

Natural Gas Combined Cycle New Source Performance Standards

C-19-EDF-01
to:

Environmental Defense Fund
257 Park Avenue South
New York, New York 10010
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February 28, 2019

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Contents

Executive Summary

In December 2018, the Environmental Protection Agency (EPA) proposed to revise the New Source Performance Standards (NSPS) for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants. For new natural gas combined cycle (NGCC) plants, EPA is proposing to keep the emission standard of 1,000 lb CO_2/MWh-gross that was finalized in 2015. An analysis of CO_2 emission rates using EPA's Air Markets Program Data (AMPD) found that more stringent emissions limits are possible for NGCC units. For the top 10% of units operating over the past ten years, the average 99% confidence rate (only 1% chance that the rate will be exceeded) was found to be 830 lb/MWh and the median 99% confidence rate was 821 lb/MWh-gross.

Emissions for new NGCC plants installed in the years 2015-2018 were evaluated in addition to the emissions for all plants operated over the ten-year period of 2009-2018. This analysis demonstrated that an NSPS rate under 1,000 lb/MWh-gross is readily achievable using current technology under a wide variety of operating conditions. The 99% confidence rate was 918 lb/MWh. Because these are new units, there is a significant likelihood that this operation includes significant amounts of time at simple-cycle mode, which may explain the higher rate than for the analysis of 10-year data.

It is clear from this data that an NSPS emission rate well below 1,000 lb/MWh-gross is supported. Based upon the data an NSPS emission rate of 900 lb/MWh-gross is readily attainable under a wide range of conditions using modern, efficient NGCC technology.

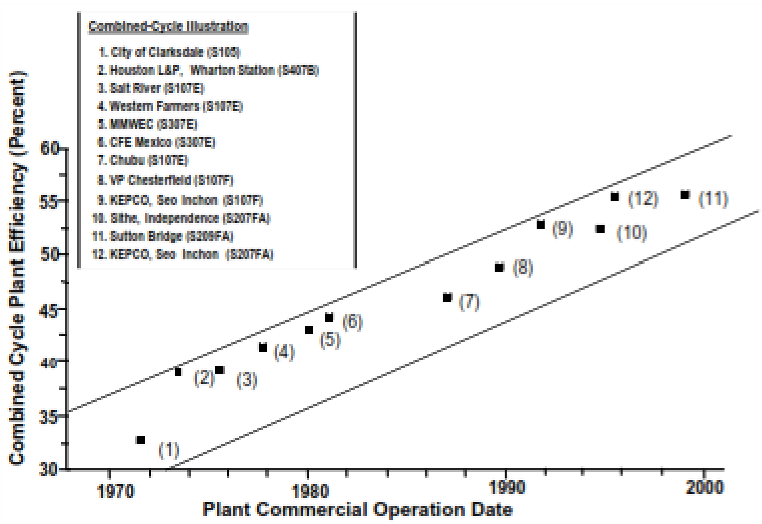
Program Results

EPA is proposing not to revisit the emission standard of 1,000 lb CO_2/MWh-gross for new NGCC plants that it finalized in 2015. Modern NGCC plants are capable of lower emission rates. Using EPA's AMPD for recently installed units as well as performance data for newly installed units that are overseas, I determined that lower emission rates than those proposed is readily achievable under a wide range of operating conditions using modern NGCC technology.

NGCC Background

The efficiency of NGCC plants have evolved rapidly over the decades. Modern NGCC plants are capable of over 60% efficiency (LHV, net). Figure 1 shows the evolution of NGCC power plant efficiency from 1970 to 2000. As shown, efficiency grew from about 35% to about 55% (LHV, net) in that time. Today, the highest efficiency gas turbine has achieved over 63% efficiency (LHV, net).[1] Gas turbine efficiency is most often described in terms of lower heating value (LHV) and net rather than gross power output.

Figure 1. Evolution of NGCC efficiency, 1970-2000.[2]



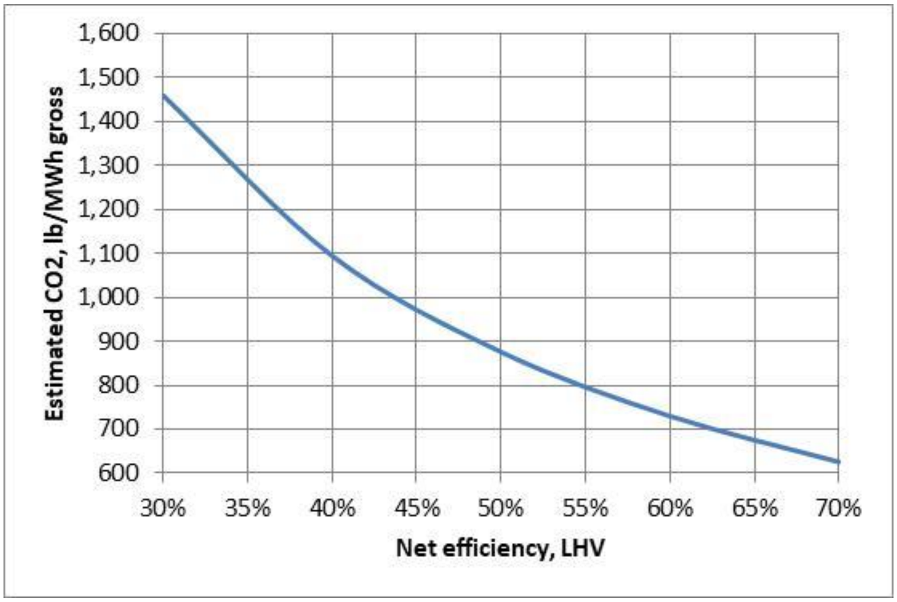
As efficiency has grown, the CO_2 emission rate per MWh produced has declined. Figure 2 shows estimated CO_2 emissions rate (gross, HHV) as it relates to gas turbine combined cycle efficiency (LHV net). For this figure, I have chosen to represent emission rate in lb/MWh-gross because this is the basis of the proposed NSPS emission rate. I have chosen to represent efficiency in terms of net, LHV because that is how gas turbine efficiency is most commonly

[1] BREAKING THE POWER PLANT EFFICIENCY RECORD...AGAIN, March 17, 2018, !https://www.ge.com/power/about/insights/articles/2018/03/nishi-nagoya-efficiency-record

[2] Chase, David L., "Combined-Cycle Development Evolution and Future", GE Power Systems, GER-4206, October 2000

represented. In doing this I have assumed that higher heating value (HHV) of natural gas equals 1.11 times the LHV and that balance of plant loads are about 1.7% of gross output.[3] As shown, EPA's current NSPS rate of 1,000 lb/MWh-gross is consistent with an efficiency of roughly 43%, which, according to Figure 1, was achievable in 1980. It is true that various factors during normal operation will impact that efficiency from what is expected under design conditions; however, as the emissions data will show this is still well off of what modern combined cycle gas turbine plants can achieve.

Figure 2. Estimated CO_2 emission rate versus NGCC Net efficiency.[4]



Modern NGCC Efficiency and Emissions Data

EPA's Air Markets Program Data (AMPD) was used to assess the actual emissions of NGCC plants in the United States. Two data sets were evaluated – all NGCC units operated over the past 10 years and new units that became operable since 2015.

NGCC Units 2009-2018

One dataset that was examined was the emissions of all NGCC plants in the AMPD database that were operated over the 10-year period 2009-2018.[5] The number of units was 1038 and CO_2 emissions data was available for 995 units. Figures 3 and 4 show the CO_2 emissions

[3] Combined Cycle 10 years.xls
[4] Combined Cycle 10 years.xls
[5] A full year of 2018 data was not available at the time, but three quarters of data was available.

rate versus average generation per year and average hourly generation, respectively.[6] Each point on the graph represents a combined cycle unit. As shown, there is a wide range of CO_2 emission rates at the lower generation rates per year. This is because some of these units operate in a simple-cycle mode for a significant period of time and are therefore less efficient. Simple cycle turbines are in the range of 25% to 35% efficient and therefore have emissions rates in the range of 1,200 lb/MWh to 1,500 lb/MWh. For those units that have low operating levels, emissions can be even higher.

These figures demonstrate that:

- Out of 995 units where data is available 592 (59.6%) had an average emissions rate below 1,000 lb/MWh-gross.
- The emission rate generally declines as both average generation per year and average generation per hour increase.
- At all levels of generation most units achieve under 1,000 lb/MWh-gross.
- At higher levels of generation, well under 1,000 lb/MWh is achieved.

The top 10% (top 100) of those units that had CO_2 emissions rate information were evaluated further. The top performing plants were throughout the United States, but the very best performing plants were in warm climates – Louisiana, Texas, Florida – which demonstrates that even in warm climates high efficiency and low emission rates are possible. In fact, states with warm climates were the most represented in the top 100. Of the top 100 plants, 18 were in Florida, 10 in Alabama, 9 in Texas, 6 in Louisiana, 7 in Georgia, all warm climates where efficiency would be expected to be lower than in cooler climates. Of the top 100 units, 65 had ten years of data, meaning that they were at least ten years old and therefore did not represent the current state-of-the-art. Because nearly two thirds of these units were at least ten years old – not reflecting the most current NGCC technology - even better performance is possible with current technology.

[6] Average generation per year was determined by total MWhs over all years reported times 12 and divided by the number of months reported. Average hourly generation was determined by dividing total MWhs reported by total operating hours.

Figure 3. CO_2 emission rate versus average generation per year[7]

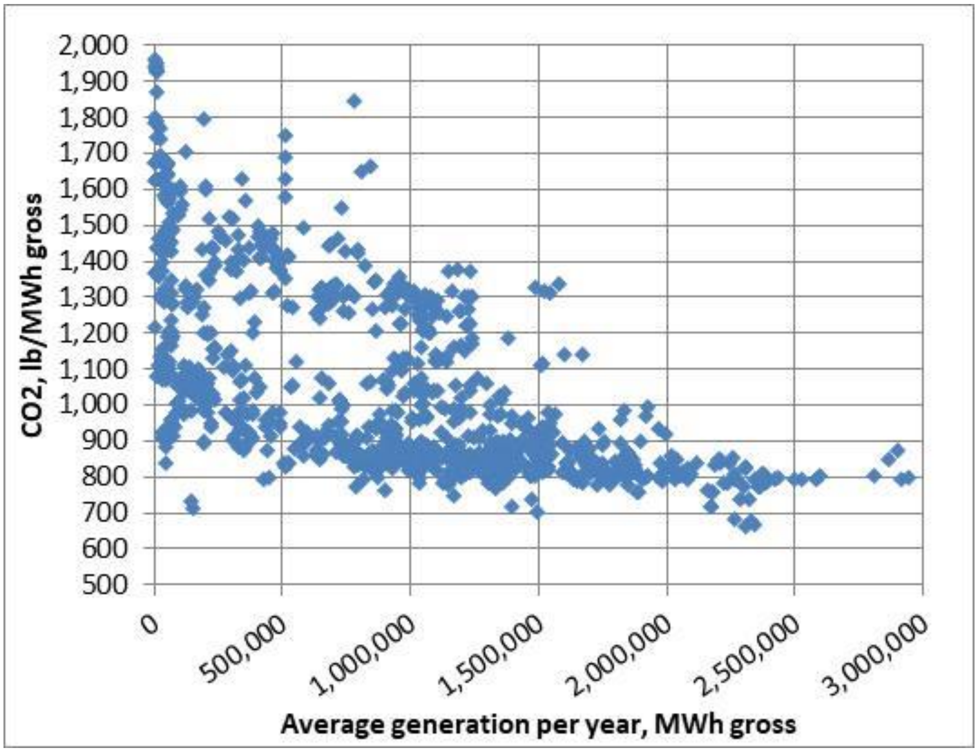
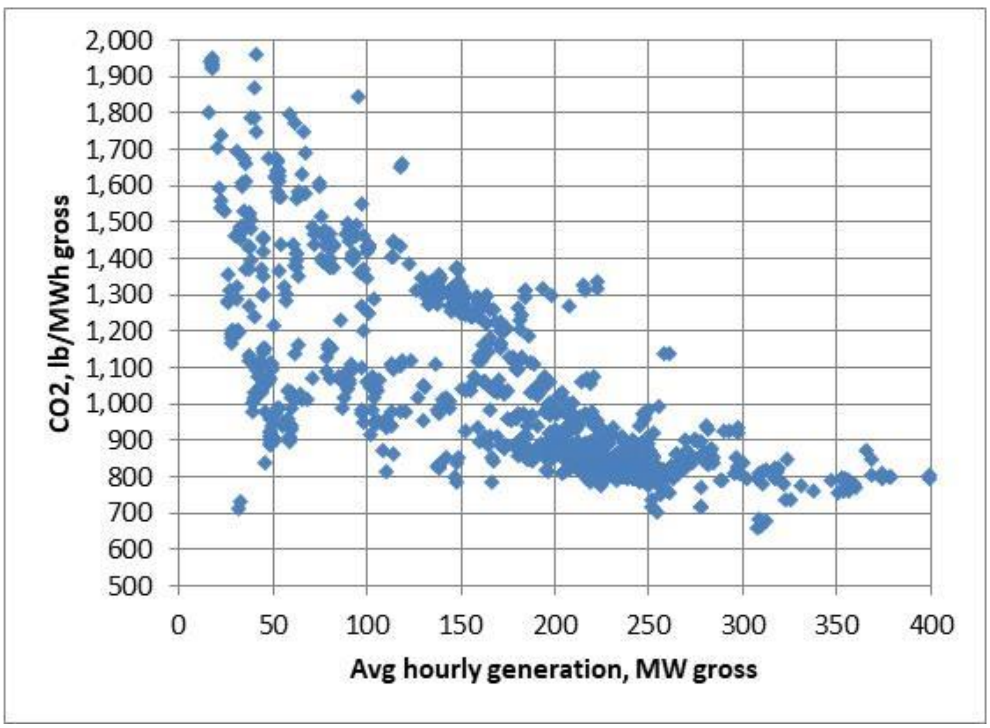


Figure 4. CO_2 emission rate versus average hourly generation[8]



[7] Combined Cycle 10 years.xls
[8] Ibid

The top 100 units ranged from an average hourly load of 32 MW to 401 MW – a wide range of plant sizes. The average load was 280 MW and median hourly load was 261 MW. The average CO_2 rate was 782 lb/MWh-gross and the median was 795 lb/MWh-gross. A 99% confidence rate was estimated for each unit by taking the population standard deviation (stdevp) of the annual emission rates for each unit, multiplying it by 2.33 and adding that to the average emission rate for the unit. The average 99% confidence rate for the top 100 units was 830 lb/MWh-gross and the median 99% confidence rate was 821 lb/MWh-gross. Of the top 10% (best 100 units), only two had 99% rates above 1,000 lb/MWh-gross, and these were at the same facility and only had (under) two years of data (Doswell Limited Partnership in Virginia). The data for Doswell Limited Partnership is questionable since the annual CO_2 emissions rate was as low as 594 lb/MWh-gross to slightly over 1,000 lb/MWh-gross.

It is apparent from the best 10% units

- which represents facilities that are operated at different locations in the country, and a large number in warm climates where efficiency would be expected to be less,
- a majority of which are at least ten years old and are therefore not state-of-the-art,
- and represent a wide range of unit sizes

that an NSPS emissions rate well below 1,000 lb/MWh-gross can be achieved using currently available technologies over a wide range of situations.

Examination of New Unit Data since 2015

In addition to examining the data of units operating over the past 10 years, data from units installed in 2015-2018 were examined. Units installed since 2015 are expected to represent the performance of new NGCC plants. Forty-nine units that became operable during this period were found in the AMPD data. These units are from eighteen different states and cover a wide range of climates – from Texas, Florida, Oklahoma and California to cooler states such as Massachusetts, Connecticut, Illinois, Michigan, New York and New Jersey. The average loads range from 59 MW (Holland Energy park in Michigan) to 504 MW (Moxie Freedom Generation in Pennsylvania).

The average emission rate[9] for the period for each of the units since the units were installed versus total generation are shown in Figure 5. Scattergood (California) and two units at Key Energy Center (Maryland) have emissions typical of simple-cycle turbines. Scattergood has been operated in this mode all four years, having an average load of 183 MW and having a rated output of 217 MW from the gas turbine and 119 MW from the steam turbine for a total rated output of 336 MW.[10] The Keys Energy Center was placed in service in 2018 with each unit operating only about 500 hours. Average load totaled 419 MW on the two units with a total MW output of 755 MW.[11] Not shown in Figure 5 is the emission rate for Garrison Energy Center in Delaware, which had an average emission rate of over 5,000 lb/MWh because the first year emission rate was extremely high (the 19,424 lb/MWh-gross value for 2015 is far too high to be realistic and no-doubt is the result of a reporting error or instrument error) and subsequent emission rates were in the range of 820 lb/MWh.

[9] Calculated by multiplying the total reported tons of CO_2 times 2000 and dividing by the reported gross generation.
[10] Rated output from 2017 EIA Form 860
[11] http://www.psegkeysenergycenter.com/about/

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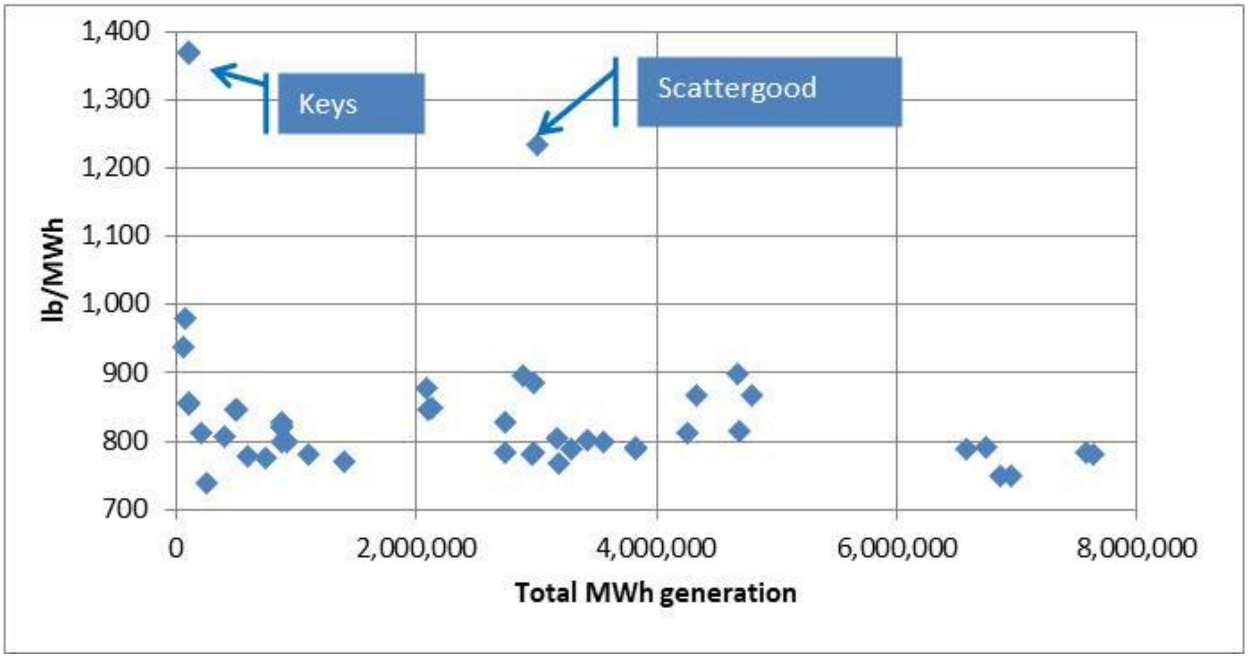
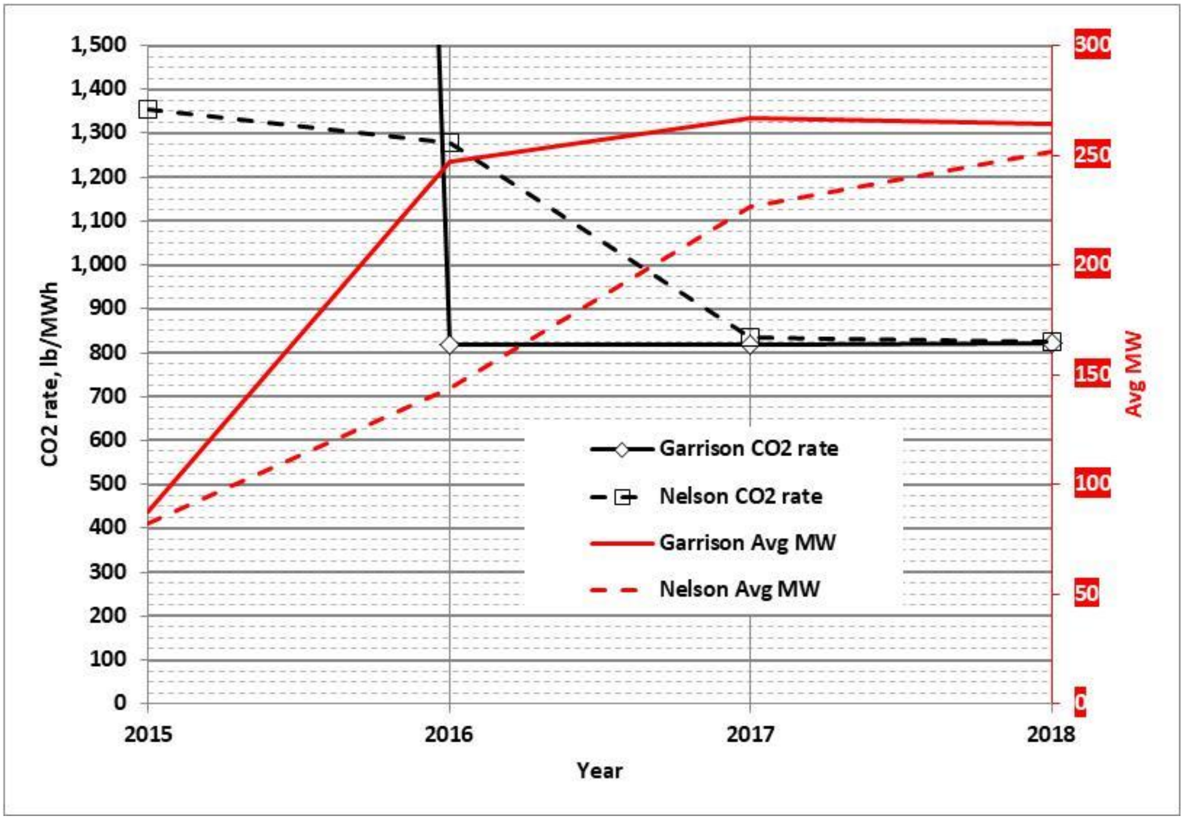
Figure 5. Average emission rate for new units operable since 2015 versus total generation.[12]



Average emission rate over the period and average load over the period are closely related if the units spend a large part of their time in simple-cycle mode. This is demonstrated in Figure 6, which shows the emission rate and average loads for Garrison Energy Center (Delaware) and Nelson Energy Center (Illinois). As shown, as both facilities' loads increase, the emission rate also decreases to around 820 lb/MWh-gross.

[12] Combined Cycle.xls

Figure 6. Average load and emissions rate for 2015-2018 for Garrison Energy Center and Nelson Energy Center.[13]



To determine an NSPS rate all of the annual emission rates for each year where the units appeared to primarily be operating in a combined cycle mode were evaluated. In some cases there is likely some significant level of simple-cycle operation. The average emission rate was found to be 809 lb/MWh. The population standard deviation was found to be 47 lb/MWh and the 99% rate was found to be 918 lb/MWh, as shown in Table 1. It is not unusual for new units to experience a significant amount of simple-cycle operation in the first year as systems are placed into service. Since this data is from newer units, there is a greater likelihood that this includes a significant amount of simple-cycle operation, which may explain why it results in a higher rate than the 10-year data.

Table 1. Annual emission rates of combined cycle systems when primarily operated in combined cycle mode[14]

Avg of rates	809
std dev	47
99% rate	918

[13] Combined cycle.xls

[14] Years where the unit was clearly operated primarily in simple-cycle mode were excluded. Data from some years may include some significant amount of simple-cycle operation which will increase the emission rate from what a combined cycle rate would be.

Summary of results

It is clear from analysis of both 10-year data and data from units installed since 2015 that an NSPS rate for CO_2 emissions of lower than 1,000 lb/MWh-gross is supportable. The 10-year data suggests that a rate of 821-830 lb/MWh may be supported. New unit data, that likely includes some simple-cycle operation, resulted in an average rate of 809 lb/MWh and a 99% rate of 918 lb/MWh. Since this data likely includes some level of simple-cycle operation, the 918 lb/MWh value may be on the high side. Based upon both data sets an NSPS rate of 900 lb/MWh-gross would likely be a very conservative NSPS emission limit as it is well above the 99% rate for the top 10% of the operating units.