THE BUCKEYE INSTITUTE

Comment on EPA's Proposed Rule for New and Existing Fossil Fuel-Fired Power Plants

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Abbreviation Definitions

BSER – Best System of Emission Reduction
CAA –Clean Air Act
CCS – Carbon Capture and Sequestration
CO_2 – Carbon Dioxide
DOE –Department of Energy
EGU – Electricity Generating Unit
EOR –Enhanced Oil RecoveryEPA – United States Environmental Protection AgencyMT – Metric Tonnes
MW – Megawatt
MWe – Megawatt-equivalent
NETL – National Energy Technology Laboratory
SaskPower – Saskatchewan Power Corporation
SCC –Social Cost of Carbon
WAG – Water-Alternating-Gas

Glossary

Capture rate –the rate at which a CCS plant can remove CO_2 from treated flue gas. Capture rate does not equate to total emissions from a plant.

CO_2-EOR – an Enhanced Oil Recovery method whereby CO_2 is injected into a mature well, typically using a WAG process, to recover 30-70 percent of the residual oil stored in an oil formation's small rock cavities.

Enhanced Oil Recovery (EOR) – a series of methods and used to extend the productive life of a mature oil field, typically by injecting gases, such as ethane, nitrogen, and CO_2, into a well in a WAG configuration.

Flue gas – the emissions from a coal or natural gas fired EGU.

Treated Flue Gas – the amount of flue gas subjected to treatment by a CCS, rated in MWe.

Introduction

There are many flaws with the Environmental Protection Agency's (EPA) proposed rule for limiting emissions from sources of greenhouse gas. Chief among them is the EPA's recommendation of carbon capture and sequestration (CCS) systems as the best systems of emission reduction (BSER) for coal-fired electricity generating units (EGUs) that intend to operate beyond 2039. In more than two decades, no government funded CCS pilot program or commercial-scale facility has adequately demonstrated the BSER. This means that the EPA's BSER is not viable and therefore cannot be a "best" system of emission reduction. Concerningly, forcing compliance with EPA's BSERs will likely exacerbate an impending energy security and reliability crisis by dissuading utilities from investing in reliable baseload sources of electric power, and pigeon-holing them to adopt intermittent—and consequently unreliable—renewable power sources.

The EPA's proposal to adopt CCS as a BSER, and its standard for states to meet based on CCS, are arbitrary, capricious, and an abuse of discretion. The EPA justifies its standard by providing examples of CCS facilities that do not meet the agency's proposed standard. The sources for the EPA's examples do not demonstrate what the EPA claims. Further, the EPA ignores important aspects of implementing CCS systems.

Despite ample evidence proving CCS has never met the Clean Air Act's (CAA) criteria for "adequate demonstration" of a BSER, the EPA is not offering any other BSER for existing coal-fired-EGUs "other than CCS with 90 percent capture."[1]

The EPA has presented CCS as a burgeoning, cost-effective, and fully functional technology capable of mitigating the majority of all coal-fired power plants' emissions. But no existing CCS plant has managed to achieve the proposed BSER's required 88.4 percent reduction in total carbon dioxide (CO2) emission via a 90 percent CO2 capture rate from a full CCS system – which the EPA's BSER would functionally require. And the EPA misreported, misrepresented, and misinterpreted its primary examples of commercial CCS facilities attaining a 90 percent capture rate.[2] Although every plant demonstrated the ability to capture CO2 from flue gas emissions, every plant failed to achieve the minimum emissions reduction target that the EPA set for the proposed BSER. No CCS facility has demonstrated a consistent ability to sequester 90 percent of total greenhouse gas emissions.

Figure 1 shows the EPA's view—or at least hope—of CCS's current technological capability based on a hypothetical CCS process designs presented in a National Energy Technology Lab (NETL) report.[3] Figure 2 shows the actual capture rate and total emissions mitigation achieved by SaskPower's Boundary Dam Unit 3's CCS facility in 2022. The EPA cites the SaskPower Boundary Dam as the best-case example of current CCS technology. SaskPower's demonstrated capture rate

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[1] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.
[2] *Ibid.*
[3] Tommy Schmitt et al., **Cost and Perforamnce Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.

is far below what the EPA has claimed, and well below the BSER's proposed 88.4 percent emission reduction.

Figure 1: EPA REQUIRED EMISSION REDUCTION PLAN

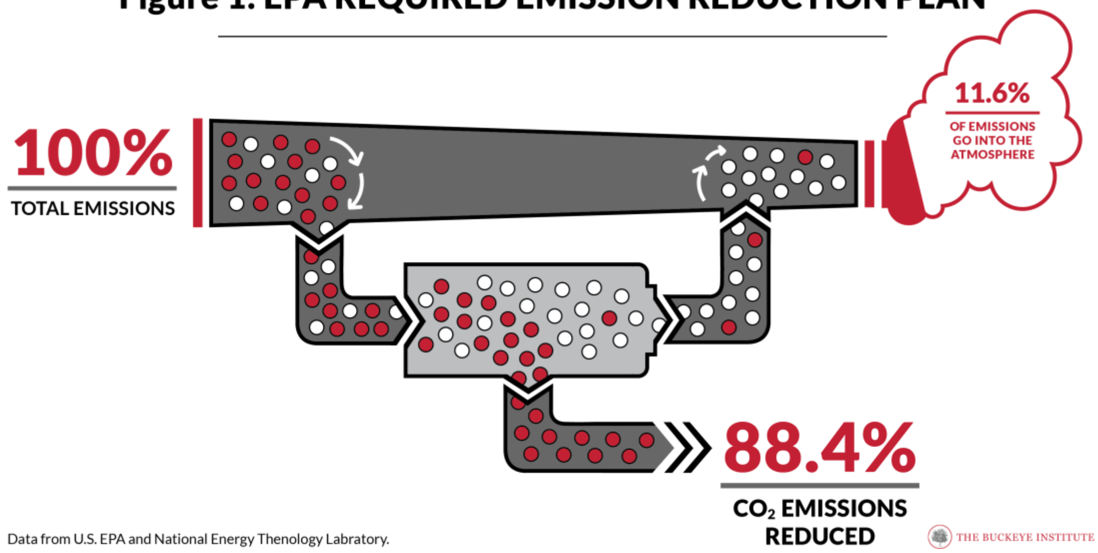
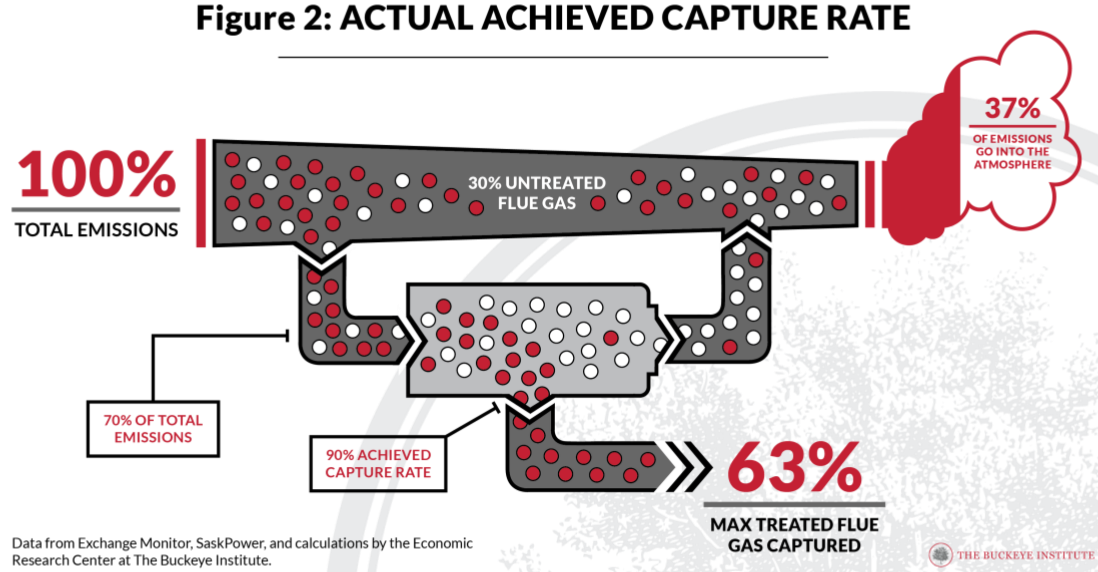


Figure 2: ACTUAL ACHIEVED CAPTURE RATE



The EPA's arbitrary standard does not reflect what CCS has achieved or is scientifically capable of achieving. Yet, the EPA will require all existing long-term coal fired EGUs to implement these costly retrofits.

Additionally, the EPA has also set a BSER for existing natural gas and oil fired EGUs. These new emission rate caps placed on baseload EGUs threaten to worsen grid reliability and trigger an energy security crisis in America. Last year, Americans saw electricity rates increase 15.8 percent, the greatest year-over-year rate increase in two decades.[4] The EPA's proposed restrictions on coal and natural gas fired power plants that provide over 80 percent of America's electric power, present a problem for meeting increased power demand. Utilities will be dissuaded from investing in baseload sources of power dependent on fossil fuels and pigeonholed into using intermittent sources of renewable power to meet America's ever-growing energy needs.

The EPA's Regulatory Impact Analysis failed to adhere to defensible and sound procedures for quantifying costs and benefits. Instead, the agency cherry-picked a range of real discount rates for use in unreliable integrated planning models when calculating the social cost of carbon (SCC) and estimating compliance costs. By discounting the SCC at 2.5, 3, and 5 percent at the 95th percentile of climate damage estimates, the EPA failed to adhere to OMB Circular A-4's guidelines for discounting by omitting the prescribed real discount rate of seven percent. Similarly, the EPA did not discount the national electricity sector's compliance costs at Circular A-4's required discount rates of three and seven percent. Instead, the EPA selected a single discount rate—3.76 percent—to estimate compliance costs in its integrated planning model. By using lower discount rates to estimate the social cost of carbon and the compliance costs, the EPA vastly overstates the benefits of the new regulations while severely understating compliance costs.

In its current form, the proposed rule will jeopardize America's energy security by making cheap power scarce and markedly increasing power costs for all Americans, rich and poor alike. America's poor and minority communities, however, will be the most impacted by higher utility rates, which are tantamount to a regressive tax.

I. The EPA's Proposed BSER.

The EPA's proposed rule requires all existing coal plants to comply with the standards based on the agency's established BSER. The BSER instructs all existing coal plants to retrofit their EGUs with CCS technologies with a minimum capture rate of 90 percent or reduce total CO_2 emissions by 2030—a mere seven years from now. Coal plants that do not—or cannot—comply with the proposed rule's BSER will be required to implement 40 percent natural gas co-firing and submit a plan to shut down coal-fired generating units by 2032.[5] Based on a NETL report, the EPA asserts that a 90 percent capture rate will result in an overall reduction of coal plant emissions by 88.4 percent. The EPA has set 88.4 percent emission reduction as the minimum emission reduction target and has provided CCS as the only "demonstrated" technology capable of meeting this target.

All CCS facilities cited by EPA used an amine-based solution to absorb CO_2 from flue gas emissions. The process for capturing CO_2 from flue gas is energy intensive, consuming more energy than what an EGU can produce. Ali et al. (2023) states that "the current energy penalty level of CO_2 chemisorption is still unbearable if a full-scale CO_2 removal process is to be

[4] U.S. Bureau of Labor Statistics, **12-month percentage change, Consumer Price Index, selected categories – Electricity**, (Last visited June 27, 2023).
[5] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

implemented for… coal-fired power plant[s].”[6] CCS plants use most of their energy to compress flue gas and heat treating the amine-solution to release the trapped CO_2.[7]

CCS facilities consume a lot of power to scrub CO_2 from flue gas. The electric power used in the processes can either be drawn directly from the attached coal-fired EGU or produced by an ancillary generator. When the CCS facility is integrated with the EGU, it results in a parasitic load that reduces overall power output,[8] which can raise electricity rates for consumers in the region near the coal-fired EGU. The immense energy inputs required to sequester CO_2 at a large-scale makes it physically impossible for a CCS facility integrated into an EGU to attain and sustain a 90 percent capture rate without consuming more energy across the CO_2 sequestration lifecycle than is produced by the coal fired-EGU. Non-integrated CCS facilities will need to draw from a reliable and dispatchable power source, *e.g.*, natural gas, nuclear, or coal fired power.

The EPA cited three coal fired facilities utilizing CCS as primary evidence for the BSER. None of the cited CCS facilities, however, achieved a consistent 90 percent capture rate on a significant portion of the emissions covered by the regulation. No commercial CCS facility has successfully met the EPA’s requirement to reduce total emissions by 88.4 or continuously sustain a 90 percent capture rate over a long-term period.

II. The Proposed Rule’s Technical Problems.

The proposed rule’s defects begin with misquoted sources and extend to inconsistent standards and irrelevant concepts that confuse and mislead.

a. Incorrect Citations and Misquotations.

As evidence to establish the BSER, the EPA stated that SaskPower’s Boundary Dam Unit 3’s CCS facility demonstrated the “commercial-scale… of solvent-based post-combustion CO_2 capture systems at power generation facilities (specifically PC plants) [and] has shown the ability to capture 90 percent of the CO_2 in the flue gas stream.”[9] The proposed rule’s justification for this assertion—the 2022 NETL report—never stated that the plant achieved a 90 percent rate of capture.[10] A single data point taken from Figure 7 in Giannaris’ report implies that a 90 percent capture rate of Unit 3’s total emissions was achieved once in 2015 for a single day. The remaining data in the time series shows that Boundary Dam has never sustained a 90 percent capture rate.[11] The proposed rule also cites the 2022 NETL report to provide the 88.4 percent emission reduction

[6] Emad Ali, Mohamed K. Hadj-Kali, Salim Mokraoui, Rawaiz Khan, Meshal Aldawsari, Mourad Boumaza. “**Exergy analysis of a conceptual CO_2 capture process with an amine-based DES**,” *Green Processing and Synthesis* Volume 12, Issue 1, February 16, 2023.
[7] Tom Yelland, **The Role of Solvents in Carbon Capture**, CarbonClean.com, August 17, 2021.
[8] **CO_2 Capture Technologies, Post Combustion Capture (PCC)**, Global CCS Institute, January 2012.
[9] Tommy Schmitt et al., **Cost and Perforamnce Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.
[10] Stavroula Giannaris et al., **SaskPower’s Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability**, 15th International Conference on Greenhouse Gas Control Technologies, March 2021.
[11] *Ibid.*

standard. But the NETL report misrepresented Giannaris' report when citing it as a justification for the following claim: "Commercial-scale demonstration of solvent-based post-combustion CO_2 capture systems at power generation facilities… has shown the ability to capture 90 percent of the CO_2 in the flue gas stream."[12] SaskPower's Boundary Dam Unit 3 was only able to achieve a 90 percent capture rate by reducing the intake of untreated flue gas. Reducing the plant's flue gas intake resulted in a de-rating of the CCS plant's effective target to a maximum capture rate of 65 percent of total emissions, which the plant has yet to demonstrate.[13] The EPA has failed to accurately cite a scientific study as primary evidence for its BSER and must therefore change its standard to reflect what the scientific report stated or provide new scientific evidence that supports, clarifies, contextualizes, or qualifies the claim that Boundary Dam Unit 3 achieved its targeted capture rate.

b. Inconsistent Baseline for Reporting Reduction in Carbon Capture.

One of E.O. 12866's objectives is to make the regulatory review process "more accessible and open to the public."[14] Undermining this objective, the metric Megawatt equivalent (MWe) is a confusing metric and a poor choice for rating a CCS system's CO_2 capture capabilities. Unaccompanied by an EGU's generation capacity, fuel type, and total daily emissions, MWe is a useless measure of CCS capture that has been misunderstood and inconsistently reported. Indeed, even the EPA has shown its misunderstanding by its inconsistent use of MWe throughout the proposed rule. Without a quantitative metric, it is impossible to measure the efficacy of CCS.

A watt is a unit[15] equal to 1 Joule per second and used to measure instantaneous power. A watt hour (Wh) is the measure of continuous electrical energy needed to power a device. Typically, lightbulbs and small household appliances have energy requirements rated in watt hours. A Megawatt (MW) is a million watts and represents power equal to 1,000,000 Joules per second. Because power plants generate a lot of electric power, their capacity is typically given in Megawatts. Unlike MW, Megawatt-equivalent (MWe) is not a unit that measures the rate of energy flow per unit of time. Instead, MWe can have many different meanings depending on the context.

In America, CCS facilities use MWe to qualitatively describe their nameplate capture capacity. Every MW generated at a coal-fired power plant releases a quantity of emissions. MWe measures the emissions released by the coal plant per MW produced. For example, A CCS facility rated at one MWe captures the emissions released by the coal plant per one MW of power generated.

MWe is a poor metric for several reasons. First, MWe can easily be confused with MW. MW measures power generated. Worse yet, megawatt electric, which measures the electric power produced by a boiler, uses the same abbreviation, MWe, to differentiate electric MW and MW

[12] Tommy Schmitt et al., **Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.
[13] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.
[14] E.O. 12866
[15] **What is a Megawatt**, Nuclear Regulatory Commission (Last visited June 29, 2023).

thermal generated by the heat engine.[16] Consequently, MWe can be and has been interpreted as a unit for measuring a CCS plant's power consumption and total emissions mitigated. Second, CCS facilities rated in MWe only describe emissions captured at the coal plants they are attached to and are not a uniform method of emission reduction. Coal plants do not uniformly emit CO_2. Emissions can vary drastically between coal-fired power plants depending on the type of coal used, the efficiency of the boiler, turbine, and the cooling process. Thus, a 25 MWe CCS facility at one coal plant may be less effective at a different coal plant, making it an inconsistent metric for rating a CCS facility's capture rate. Third, MWe on its own does not convey information about total generation capacity or the operational schedule of the coal plant, which determines emission intensity and is an important detail for measuring effectiveness of the CCS facility. Without the coal plant's generation capacity or active capacity, MWe does not convey any information about the measured capture rate. Using MWe to represent capture capacity overstates the measured capture rate of most plants. Most CCS facilities target a 90 percent capture rate from a stream of flue gas. At a 25 MWe CCS facility, the plant only offsets 22.5 MWe of emissions. MWe's shortcomings make it an unhelpful and inconsistent metric for comparisons between CCS systems.

Due to the similarities to MW and inconsistent reporting, MWe is also a confusing metric for those unfamiliar with the terminology of CCS plants. MWe can be interpreted as any one of the following: the power rating of the CCS plant, the thermal energy in the waste flue gas stream, the parasitic load of an integrated CCS plant, or as the emissions mitigated per MW of power. These varied interpretations inevitably cause misunderstandings and distort or omit important information about the CCS facility.

Even when used and understood correctly, MWe says nothing about the CCS facility's actual achieved CO_2 capture rate or the percentage of total emissions mitigated from the coal plant. Reporting a CCS facility's maximum capture potential in MWe without the generation capacity of the EGU it is attached to, as the EPA did at Petra Nova and Plant Barry, is misleading and ultimately says nothing about the total emissions captured by the plant.

The EPA inconsistently used MWe throughout the proposed rule when describing the capture rate of several CCS facilities. The EPA described Petra Nova as a "240 MW-equivalent capture facility," and Plant Barry as a "25-MW CCS project." But subsequent scientific studies conducted by Mitsubishi (the patent holder of the KM-CDR™ process used at both plants) consistently use MWe as a rate for capture capacity.[17] Although the EPA correctly reported Petra Nova's capture capacity in MWe, it incorrectly reported Plant Barry's 25 MWe as a 25 MW capture facility. This error can be interpreted several ways: Plant Berry draws a parasitic load of 25 MW or Plant Barry is capable of mitigating 25 MWe of emissions from a flue gas slipstream. The EPA then

[16] **Megawatts electric**, Energy Education, University of Calgary (Last visited: July 18, 2023).
[17] Osamu Miyamoto, Cole Maas, Tatsuya Tsujiuchi, Masayuki Inui, Takuya Hirata, Hiroshi, Tanaka, Takahito Yonekawa, and Takashi Kamijo, **KM CDR Process™ Project Update and the New Novel Solvent Development**, Energy Procedia, November 18, 2016 ; Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.

indiscriminately switches between MWe and MW when describing capture capacity of several proposed CCS projects.

To prevent future confusion and to determine if CCS is a viable technology, the EPA should consider adopting a metric other than MWe. The new metric should be easily understandable, reportable, and comparable to total emissions and better assess the performance of the CCS facility. For example, The Saskatchewan Power Corporation (SaskPower) uses daily CO_2 capture in metric tonnes (MT) as a reporting metric for their captured CO_2 emissions. Average daily CO_2 capture rate offers several benefits over MWe. First, average daily CO_2 capture can be easily understood when reported by itself. Second, average daily capture presents a clear picture of the total emissions captured by the CCS plant on a daily basis. This number can trivially be divided by total plant emissions to assess the day-to-day performance of the plant. Third, daily capture rate creates a continuous stream of emissions data that can easily be aggregated and audited by the public to assess the performance of the CCS facility month-to-month, quarter-to-quarter, or year-to-year. Average daily capture rate simplifies the reporting of CO_2 captured by a CCS plant and makes it easier to assess the performance of a CCS facility.

Several NETL reports have used pounds of CO_2 per megawatt hour (lb/MWH) to measure CCS efficacy.[18] But although it is a superior metric to MWe, MW/ton of CO_2 can vary from site to site depending on fuel type and efficiency of the CCS plant.

The EPA needs to consistently report the capture capacity of the CCS facilities used to justify its BSER and adopt a more transparent metric that adequately describes a CCS facility's actual performance rather than its projected emission mitigation capacity, which, as will be demonstrated, has rarely been consistently achieved.

III. The Proposed Rule is Arbitrary, Capricious, and an Abuse of Discretion.

The laws of physics always trump the laws of man. The proposed rule demands the opposite.

Under the Administrative Procedure Act, agency action, findings, and conclusions must be held unlawful and set aside if found to be arbitrary, capricious, an abuse of discretion, contrary to constitutional power, or otherwise not in accordance with law.[19] Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors that Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.[20] Additionally, the agency must "examine the relevant data and articulate a satisfactory explanation for its action

[18] **Eliminating the Derate of Carbon Capture Retrofits**, National Energy Technology Laboratory, May 31, 2016; Tommy Schmitt et al., **Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.
[19] 5 U.S.C § 706(2).
[20] *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins.*, 463 U.S. 29, 30 (1983).

including a rational connection between the facts found and the choice made."[21] And as part of the required analysis for determining the BSER, the EPA must consider only viable technologies.[22]

Instead of following these prescribed norms, the proposed rule has not considered important aspects of the problem, it has not fairly examined the relevant data, has determined that an unproven—even speculative—technology is the "best system" for emissions reduction, and has based its Section 111(d) standard on the unproven technology's theorized emissions reductions. These theoretical emissions reductions cannot be achieved by the state plans in any way other than attempting to use the unproven technologies or shutting down plants entirely.

a. The Proposed Rule's CSS Examples Violate the CAA § 111(a)(1) Criteria.

i. Plant Barry

Prior to 2011, the Southern Company partnered with Mitsubishi Heavy Industries to attach a small 25 MWe CCS pilot facility to the James M. Barry Electric Generating Plant's (Plant Barry) Unit 5, a 770 MW capacity coal fired EGU in Alabama.[23] Plant Barry's auxiliary CCS plant commenced operation in 2011, and had a maximum capture capacity of a mere 550 MT of CO2 per day, enough to offset just three percent of Unit 5's total CO2 emissions.[24] Plant Barry's CCS plant was the only CCS facility cited by the EPA that consistently achieved and sustained a stable capture rate of 90 percent, but it showed that very small-scale CCS was possible.[25] This limited success did not demonstrate, however, that it was possible to achieve the EPA's 88.4 percent emissions reduction target. And given the small size of Plant Barry's CCS facility, it is certainly not representative of large-scale CCS facilities capabilities.

ii. SaskPower's Boundary Dam Unit 3 CCS Facility

The EPA cites SaskPower's Boundary Dam Unit 3's CCS facility as a successful demonstration of meeting the BSER's 90 percent capture rate and overall 88.4 percent emissions reduction target.[26] But that claim is factually inaccurate.

The CCS facility attached to SaskPower's Boundary Dam Unit 3 entered service in October 2014. After eight years of operation, the CCS facility has failed to consistently achieve its maximum designed capture rate. Mechanical and equipment failures stemming from design oversights forced the plant to reduce its operation capacity. The plant's annual capture rate is below 60

[21] *Id.* at 43.
[22] *See* 42 U.S.C. § 7411 (requiring BSER to be "adequately demonstrated").
[23] **Carbon Capture and Sequestration (CCS) Demonstration Project**, Southern Company, (PowerPoint presentation, August 21, 2009); Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.
[24] **MHI Carbon Capture Technology to be Demonstrated in United States on Southern Company Coal-Fired Power Plant**, Mitsubishi Heavy Industries press release, May 22, 2009.
[25] Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.
[26] U.S. EPA, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

percent, evidence that the CCS technology cannot meet the EPA's desired standards and so cannot be the BSER.

Between 2008 and 2014, Unit 3's generation capacity was upgraded from 139 MW to 160 MW and retrofitted with a CCS facility. The CCS facility would draw a parasitic load of 50 MW of power directly from Unit 3. The CCS facility's 50MW load reduced Unit 3's power generation capacity by 31 percent from 160 MW to 110 MW of net generation capacity.[27] The CCS facility's parasitic draw negated the additional 21 MW gained by upgrading Unit 3's generation capacity, and further reduced Unit 3's power output by an additional 29 MW, which is enough energy to continuously meet power demand for 21,750 homes.[28] By integrating the CCS facility directly into Unit 3, SaskPower reduced the amount of electricity to the grid, which doubled the wholesale power price.[29]

Unit 3's CCS plant was designed as a "full" CCS system[30] to treat 100 percent of Unit 3's flue gas emissions for 90 percent of CO2. The projected daily capture was 3,200 MT of CO2 out of Unit 3's estimated daily emissions of 3,600 MT of CO2. [31] Unit 3's CCS facility, however, only achieved its targeted 90 percent capture rate for several days in 2015 and never sustained it over a long period of time.

Attempts to run the CCS system at its designed capture rate of 90 percent over total emissions caused frequent equipment failures. Though intended to treat 100 percent of flue gas emissions, designers failed to account for fly ash from the coal plant entering the system and choking the SO2 and CO2 absorbers.[32] The fly ash contaminated and compromised the "health" of the amine solution, which severely impeded the rate of CO2 capture.[33] Repairing and cleaning the equipment required multiple months-long outages. Additional equipment failures, such as the repeated failures in the facility's CO2 compressor motor, also resulted in long downtime.[34]

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[27] J.E. Cichanowicz, "**2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation**," (January 2022); Wesley Peck, John A. Hamling, Neil Wildgust, Charles D. Gorecki, **What Parasitic Load? a New Paradigm for Ccus**, *2019 Carbon Management Technology Conference*, July 18, 2019; Abby L. Harvey, **Two Years of Operation at Boundary Dam**, Exchange Monitor: presented at Carbon, Capture, Utilization & Storage Conference, 2016 (Last visited June 26, 2023).
[28] **Understanding electricity**, California Independent System Operator (Last visited June 26, 2023).
[29] Stefani Langenegger, **Sask. Carbon capture plant doubles the price of power**, CBC News, June 17, 2016.
[30] U.S. 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**, April 2016.
[31] **SaskPower Boundary Dam 3 Project Update & Some Lessons Learned**, Cansolv Technologies Inc., March 2013; Abby L. Harvey, **Two Years of Operation at Boundary Dam**, Exchange Monitor: presented at Carbon, Capture, Utilization & Storage Conference, 2016 (Last visited June 26, 2023).
[32]Brent Jacobs et al., "**Reducing the CO2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities**," 16th International Conference on Greenhouse Gas Control Technologies (November 2022).
[33] J.E. Cichanowicz, "**2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation**," (January 2022).
[34] Carlos Anchondo, **CCS 'red flag?' World's sole coal project hits snag**, E&E News, January 10, 2022.

To mitigate equipment failures, Unit 3's CCS plant's flue gas intake needed to be downgraded from a "full" CCS system. The intake of flue gas was reduced to 70 percent of the CCS plant's designed intake capacity. Only after Unit 3's CCS facility was de-rated did the CCS facility achieve a capture rate of 90 percent CO2—but only of the 70 percent of the CO2 emissions.[35] Capture of 90 percent rate of the 70 percent of emissions reduced the CCS plant's maximum capture rate to about 65 percent of total emissions.[36] But even at the lower capture rate, the CCS facility still underperforms targets, mitigating only 57 percent of total emissions in 2021. The derating and continued under-performance of the CCS plant caused SaskPower to miss emission reduction targets.[37]

According to SaskPower, Unit 3's CCS facility was only able to capture 749,035 MT out of a designed annual capture capacity of 1,100,000 MT.[38] This puts the CCS facility's capture rate at 74 percent, well below the 90 percent of treated flue gas that the EPA claims. Out of the estimated 1,314,000 MT of CO2 emitted from Unit 3, the CCS facility was only able to capture 57 percent of total emissions (see Figure 2), well below the proposed 88.4 percent requirement.

October 2022 marked the plant's eighth year of operation. Over those eight years, the plant has only captured five million tonnes of CO2, three million tonnes short of its intended mark. Unit 3's real capture rate has been 62.5 percent of its designed capacity over its operational life[39] and has not demonstrated a satisfactory carbon capture sequestration rate to justify the EPA's proposed BSER.

iii. Petra Nova

In May 2010, NRG Energy Inc. (NRG) entered a cooperative agreement with the Department of Energy to build Petra Nova,[40] a CCS facility that would be retrofitted onto Washington A. Parish Electric Generating Station's Unit 8. Unit 8 is a lignite-fired coal boiler with a generation capacity

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[35] Brent Jacobs et al., "**Reducing the CO2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities**," 16th International Conference on Greenhouse Gas Control Technologies (November 2022).

[36] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.

[37] **SaskPower Annual Report 2021-2022**, SaskPower, March 31, 2022; Karin Rives, **Only still-operating carbon capture project battled technical issues in 2021**, S&P Global Market Intelligence, January 6, 2022.

[38] **BD3 Status Update: Q4 2022**, SaskPower.com, January 23, 2023.

[39] **Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 26, 2023).

[40] **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

of 654 MW.[41] Petra Nova was designed to capture 90 percent of emissions sourced from a 240 MWe flue gas slip stream diverted from Unit 8.[42]

Using the Mitsubishi's KM-CDR™ process piloted at Plant Barry, Petra Nova was initially designed as a 60 MWe capture plant.[43] But plans to monetize captured CO2 by selling it to on-going CO2-EOR operations in the West Ranch Oil Field required larger economies of scale.[44] If Petra Nova was going to be commercially viable, the plant would need to be scaled up to 240 MWe, a factor of 4x the original design and well above Plant Barry's capture quantity.

When operating at full capacity, Petra Nova could theoretically sequester 36 percent of Unit 8's total emissions. Petra Nova's performance, however, suffered design flaws and equipment deficiencies that severely reduced its capture rate during its early years of operation. Additionally, Petra Nova was powered by a dedicated natural gas-fired turbine that emitted CO2, which effectively negated a substantial portion of the CO2 it was designed to sequester. The emissions from the natural gas turbine offset as much as 25 percent of the sequestered CO2.[45]

To prevent a parasitic load from reducing plant generation efficiency like at SaskPower's Unit 3, Petra Nova's designers did not integrate Petra Nova with Unit 8, but instead used an ancillary natural gas-fired turbine rated at 78 MW as a dedicated power source. Petra Nova drew all 35 MW of its power from the generator and sold all excess power to the grid.[46] This avoided placing a parasitic load on Unit 8 and prevented Petra Nova from removing 35 MW of electric power – enough for 26,250 homes – from the grid.[47] Ironically, Petra Nova was a CCS facility completely powered by a fossil fuel EGU.[48]

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[41] **Petra Nova is one of two carbon capture and sequestration power plants in the world**, U.S. Energy Information Administration, October 31, 2017; **Plant Barry CO2 Capture Project**, Mitsubishi Heavy Industries, LTD., October 2015; **Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 26, 2023).

[42] Scott DiSavino, **Fire shuts NRG Texas coal power unit during hot spell, all personnel safe**, Reuters, May 09, 2022; **Petra Nova Parish Holdings: W.A. Parish Post-Combustion CO2 Capture and Sequestration Project**, NETL.DOE.gov (Last visited June 26, 2023).

[43] Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020.

[44] *Ibid.*

[45] Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020; **Petra Nova Is One of Two Carbon Capture and Sequestration Power Plants in the World**, U.S. Energy Information Administration, October 31, 2017; Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

[46] Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020.

[47] **Understanding electricity**, California Independent System Operator (Last visited June 26, 2023); Osamu Miyamoto, Cole Maas, Tatsuya Tsujiuchi, Masayuki Inui, Takuya Hirata, Hiroshi Tanaka, Takahito Yonekawa, and Takashi Kamijo, ***KM CDR Process™ Project Update and the New Novel Solvent Development***, Energy Procedia, November 14-18, 2016.

[48] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

Petra Nova's target capture rate was 1.4 million MT out of a possible 1.6 million MT of CO2 per year, roughly 40 percent of Unit 8's total emissions.[49] Operating at the targeted capacity factor of 85 percent, Petra Nova was rated to sequester 5,200 MT of CO2 per day.[50] Like SaskPower's Unit 3 CCS facility, however, Petra Nova encountered operational challenges and frequent equipment breakdowns.[51] Houston's high summer temperatures complicated the plant's water cooling process, which hurt the CCS facility's performance. Operating the plant at full capacity during the summer stressed the system and risked equipment failures to meet the area's surging power demand for air conditioning.[52] Petra Nova also suffered from non-weather-related equipment failures, including leaks from heat exchangers and calcification, which caused its flue gas blower to vibrate.[53] Technical problems ultimately led to 367 days of outages, nearly a third of Petra Nova's operational life.[54]

The proposed rule states that Petra Nova, "successfully captured 92.4 percent of the CO2 from the slip stream of flue gas processed with 99.08 percent of the captured CO2 sequestered by EOR."[55] But Petra Nova never achieved its maximum capture rate, and according to a report from the Institute for Energy Economics and Financial analysis, "Emission data for Parish Unit 8 reported to the EPA suggests the actual CO2 capture rate was substantially lower than 90%, perhaps as low as 65% to 70%. And the average capture rate does not include emissions from the gas-fired combustion turbine used to power the facility. Adding those emission lowers the overall on-site capture rate to… 55% to 58%."[56] And when considering total emissions from the W.A. Parish generating station, Petra Nova captured an even smaller percentage. In 2018, Petra Nova only captured 1.017 million MT of CO2 out of the 14.6 million MT emitted by the entire plant—a mere six percent of total emissions.[57]

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49 NRG Energy, **Petra Nova - WA Parish Generating Station**, nrg.com, accessed June 1, 2017; **Petra Nova, World's Largest Post-Combustion Carbon-Capture Project, Begins Commercial Operation**, Office of Fossil Energy and Carbon Management press release, January 11, 2017; **Plant Barry CO2 Capture Project**, Mitsubishi Heavy Industries, LTD., October 2015; **Petra Nova - W.A. Parish Project**, Office of Fossil Energy and Carbon Management press release, January 10, 2017.

50 **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

51 Valerie Volcovici and Timothy Gardner, **Biden's power plant proposal poses huge test for carbon capture**, *Reuters*, May 12, 2023.

52 **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

53 Oakley Shelton-Thomas, **Carbon Capture: Billions of Federal Dollars Poured Into Failure**, Food and Water Watch, September 27, 2022.

54 Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

55 U.S. Environmental Protection Agency (EPA), **New Source Performance… and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

56 Suzanne Mattei and David Schlissel, **The ill-fated Petra Nova CCS project: NRG Energy throws in the towel**, Institute for Energy Economic and Financial Analysis, October 05, 2022.

57 Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

Because Petra Nova was only ever designed to capture 36 percent of Unit 8's emissions at maximum capacity, and because it failed to reliably sustain a 90 percent capture rate over a long period of time, Petra Nova fails to meet the EPA's criterion of an 88.4 percent total emission reduction and does not justify CCS as a BSER.

b. CCS is Only Viable with DOE Grants and Subsidies.

The Department of Energy's (DOE) gamble on CCS technology has sent billions of taxpayer dollars chasing an elusive green dividend. Most projects that received funding from DOE in the last decade were never completed. Petra Nova was the only coal capture project that was built, but it ultimately failed to generate positive environmental benefits and cash flow. Similarly, SaskPower received 240 million CAD (US $195 million) from Canadian taxpayers.[58] But Boundary Dam Unit 3's CCS facility never profited from the commercial sale of captured CO2. In fact, CCS cost Boundary Dam millions of dollars when the CCS plant failed to deliver CO2 promised to Cenovus for Enhanced Oil Recovery. Were it not for the $50/tonne CO2 carbon tax imposed by the Canadian government, Boundary Dam's CCS plant would have been a complete failure.

Over the past decade, DOE has spent hundreds of millions of taxpayer dollars on CCS facilities. According to a Government Accountability Office (GAO) report on Carbon Capture and Storage, "DOE provided nearly $684 million to eight coal projects, [which resulted] in one operational facility"[59]—Petra Nova. However, Petra Nova ultimately shutdown due to the high cost of producing CO2 for Enhanced Oil Recovery (CO2-EOR) operations. The DOE cancelled funding agreements with four projects. The remaining $488.7 million was spread between five incipient projects that never progressed beyond paper-napkin sketches.[60]

Additionally, the GAO found that the "DOE's process for selecting coal projects and negotiating funding agreements increased the risks that DOE would fund projects unlikely to succeed."[61] The GAO concluded that the DOE's senior leadership, "did not adhere to cost controls designed to limit its financial exposure on funding agreements for coal projects… [the DOE] spent nearly $[488.7] million on the definition and design of four unbuilt facilities – almost $300 million more than planned for those projects."[62] That is a nearly 200 percent cost overrun before even starting construction.

Cost overruns at proposed CCS facilities have been well documented and devastating for utility consumers. The Kemper project was kickstarted in 2007 by Southern Power Company's

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[58] **Boundary Dam Integrated Carbon Capture and Storage Demonstration Project**, Government of Canada, January 5, 2016.

[59] United States Government Accountability Office, ***Report to Congressional Committee on Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects***. Government Accountability Office, December 2021.

[60] United States Government Accountability Office, ***Report to Congressional Committee on Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects***, Government Accountability Office, December 2021.

[61] *Ibid.*

[62] *Ibid.*

subsidiary, Mississippi Power Company, which was conceived as an integrated gasification plant with an attached CCS facility capable of capturing 65 percent of total emissions from the lignite coal fuel source.[63] The DOE fed Kemper's fiscal furnace by adding $382 million in grant funding.[64] Originally, the Kemper project was estimated to cost $2.4 billion, but quickly ballooned 212.5 percent to $7 billion and ultimately was terminated. The facility was fitted for natural gas-fired generation.[65] To recover the costs of the failed project, the Mississippi state legislature authorized Southern Power to raise consumer power rates by 41 percent, roughly $37 per household per month.[66]

Congress has since rewarded the DOE's behavior with a near blank check. The Energy Act of 2020 offered the DOE $7 billion over five years (2020-2025) to examine CCS projects at natural gas-fired power plants and industrial plants.[67] The Inflation Reduction Act (IRA) has offered an additional $12 billion in funding and billions more in tax credits for yet unproven CCS facilities.[68]

Direct Air Carbon (DAC) capture is a largely unproven method of CCS. Currently, Occidental Petroleum is building the nation's first such commercial scale facility in Ector County, Texas. DAC is a yet unproven technology with high estimated CO_2 capture costs. Current cost estimates for captured CO_2 range well above $100 - $335 per tonne of CO_2.[69] Captured CO_2 will be too expensive for utilization and the cost of capture is well above the existing tax credits. Whether this facility will generate revenue remains to be seen. The project has secured a 10-year tax abatement from Ector County despite rural Texas counties depending on property tax revenue to fund education and municipal services. The loss of tax revenue from this parcel of land is an injustice that deprives a majority Hispanic community[70] of resources to fund education and local infrastructure. The EPA's BSER encourages unproven facilities like these to squander taxpayer dollars on unproven technology and prompt coal plants to try unproven DAC facilities in poor, rural counties just to mitigate emissions.

c. The Water Use Impact Analysis Underestimates Required Water Use.

Section VII.F.3.v.iii.(C) of the proposed rule cites increased water use as a potential impediment for CCS adoption. According to the EPA, CCS technology increases an EGU's combined cycle water

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[63] Richard Esposito, **The Kemper Project IGCC Project Overview**, SECARB Stakeholders' Briefing, May 2010.
[64] James Conca, **The Largest Clean Coal Power Plant In America Turns To Natural Gas**, Forbes, July 11, 2017.
[65] David Schlissel, **IEEFA U.S.: Southern Company Demolishes Part of the $7.5 Billion Kemper Power Plant in Mississippi**, Institute for Energy Economics and Financial Analysis, October 14, 2021.
[66] Ian Urbina, **Piles of Dirty Secrets Behind a Model 'Clean Coal' Project**, *The New York Times*, July 5, 2016; Rebecca Smith, **Coal-Fired Power Plant Loses Steam: Mississippi utility withdraws as backer of electricity project as costs soar**, *The Wall Street Journal*, May 22, 2015.
[67] **DOE's Carbon Capture and Storage (CCS) and Carbon Removal Programs**, Congressional Research Service, April 4, 2022.
[68] Charles Harvey, Kurt House, **Every Dollar Spent on This Climate Technology Is a Waste**, MIT Civil and Environmental Engineering, August 17, 2022.
[69] International Energy Agency, **Direct Air Capture: A Key Technology for Net Zero**, 2022.
[70] U.S. Cencus, **QuickFacts: Ector County, Texas: Population Estimates**, July 1, 2022, Texas (Last Visited: July 20, 2023).

usage from 190 gallons to 290 gallons, increasing water usage over 50 percent.[71] Other sources indicate that the water requirements of carbon sequestration can double the per kilowatt water usage of a coal plant.[72] But the proposed rule asserts—with no supporting evidence—that all coal-fired EGUs can implement dry cooling to negate extra water requirements. Dry cooling, however, requires low ambient temperatures making it impractical for plants in hot or drought prone areas. Houston's Petra Nova, for example, used 1.49 billion gallons of water in addition to Unit 8's water consumption. High temperatures at the plant created problems that led to outages or the de-rating of the CCS plant.[73] If dry cooling will not work for the CCS plants, then it cannot work for power plants. Furthermore, very few EGUs rely solely on dry cooling technologies—and for good reason—but the proposed rule offers them as a unilateral solution without properly assessing how such a requirement would affect hot and drought prone regions.

d. Enhanced Oil Recovery.

Enhanced Oil Recovery (EOR) operations were a significant driver of early CCS technology. Today, proponents of CCS view CO2-EOR as a ready-made market for CO2 sourced from coal projects. Although the EPA acknowledges the important role that CO2-EOR will play in commercializing and sequestering captured CO2, the BSER stopped short of including it as a method—and rightly so. The success of a CCS project is determined by regional CO2 markets, geography, and plant-type. But in eschewing CO2-EOR, the EPA has overlooked the fact that commercial CO2 captured by coal projects is economically uncompetitive in every regional CO2 market. Due to strong competition from easily sourced natural and industrial CO2, it is unlikely that there will ever be an economic case for plants to adopt CCS voluntarily sans generous tax credits. The EPA's BSER will saddle coal plants with expensive facilities that will be unable to defray their maintained costs with the revenue stream generated by the sale of CO2 for EOR.

An oil field's productive life has three phases: primary, secondary, and tertiary recovery. Tertiary recovery can produce 30 – 60 percent of a field's original oil in place depending on the methods used and the price of oil.[74] CO2-EOR is one of several tertiary oil recovery methods used by petroleum landmen.[75] But CO2-EOR usually requires high oil prices to be economically viable. The inputs to CO2-EOR can raise the final production costs of a barrel of crude oil by $20 – $30 per barrel.[76] This makes CO2-EOR one of the most expensive methods of EOR, and uncompetitive

[71] U.S. Environmental Protection Agency, **New Source Performance… and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

[72] Samuel K. Moore, **The Water Cost of Carbon Capture: Coal Power's Carbon Savior Could Double Its Water Woes**, IEEE.org, May 28, 2010; Rosa, L., Reimer, J.A., Went, M.S. et al. **Hydrological limits to carbon capture and storage**, *Nature Sustainability,* Volume 3 (2020) p. 658–666.

[73] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

[74] **Enhanced Oil Recovery**, Department of Energy (Last visited Jun 28, 2023)

[75] Sean T. McCoy and Edward S. Rubin, "**The Effect of high Oil prices on EOR project economics**" *Energy Procedia*, Volume 1, Issue 1 (February 2009) p. 4143 - 4150

[76] **Oil prices drive projected enhanced oil recovery using carbon dioxide**, U.S. Energy Information Administration, July 30, 2014.

with cheaper superior methods like ethane flooding.[77] Additionally, CO2-EOR's economic viability also depends entirely on the availability and regional price of CO2.

Over the last 70 years, geography has been, and remains, the greatest influence on determining whether manmade or naturally sourced CO2 is used in CO2-EOR operations. CO2-EOR was field tested in 1964 when a CO2 slug and carbonated water were injected into a pilot well in Mead Strawn Field.[78] After CO2-EOR was proven feasible, high oil prices in the 1970s spurred landmen to find sources of CO2.[79] By 1972, several industrial gas processing facilities were providing dense quantities of captured CO2 to CO2-EOR operations in the Permian Basin.[80] By the late 1970s, several pipeline projects were planned to tap Colorado's large deposits of natural CO2.[81] By 1982, several of these pipelines were completed, carrying natural CO2 to EOR projects in the Permian basin. Today, 70 to 80 percent of all CO2 used in EOR comes from natural deposits[82] and over 90 percent of naturally sourced CO2 is almost exclusively used in the Permian Basin.[83] The remaining 20 – 30 percent of CO2 for EOR is nearly exclusively captured from industrial gasification plants, natural gas refineries, ethanol plants and predominantly used in the Rocky Mountains and Midcontinent regions where natural deposits of CO2 are either difficult to access or scarce.[84] In place of natural CO2 deposits, industrial sources of CO2 can consistently offer dense quantities of CO2 that are easier to capture, process, and sell to vendors. Coal CCS projects have attempted to breach into both markets and have largely failed because sourcing CO2 in low-concentration from flue gas cannot economically compete in any region or with any other source of CO2.

[77] Steven T. Anderson, Steven Cahan, **Estimating market conditions for potential entry of new sources of anthropogenic CO2 for EOR in the Permian Basin**, U.S. Geological Survey, Publications Warehouse, November 30, 2019.

[78] James P. Meyer, ***Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology***, Contek Solutions - American Petroleum Institute, November 24, 2004; Tuo Huang, Xiang Zhou, Huaijun Yang, Guangzhi Liao, Fanhua Zeng, "**CO2 flooding strategy to enhance heavy oil recovery**" Petroleum, Volume 3, Issue 1 (March 2017) p. 68-78.

[79] Matthew Fry, Adam Schafer, et al., **Capturing and Utilizing CO2 from Ethanol**, working paper, State CO2-EOR Deployment Work Group, December 2017; **A Brief History of CO2 EOR, New Developments and Reservoir Technologies for CO2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[80] Matthew Fry, Adam Schafer, et al., **Capturing and Utilizing CO2 from Ethanol**, working paper, State CO2-EOR Deployment Work Group, December 2017; **A Brief History of CO2 EOR, New Developments and Reservoir Technologies for CO2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[81] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[82] **Enhanced Oil Recovery**, Department of Energy, energy.gov (Last visited Jun 28, 2023); **A Brief History of CO2 EOR, New Developments and Reservoir Technologies for CO2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; Christophe McGlade, **Can CO2-EOR really provide carbon-negative oil?**, International Energy Agency, April 11, 2019.

[83] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999; Christophe McGlade, **Can CO2-EOR really provide carbon-negative oil?**, International Energy Agency, April 11, 2019; Matthew Wallace, Lessly Goudarzi, Kara Callahan, Robert Wallace, "**A Review of the CO2 Pipeline Infrastructure in the US**." *NETL*, April 21, 2015.

[84] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

SaskPower intended for Boundary Dam Unit 3's CCS facility to produce enough CO2 that captured CO2 could compete with CO2 captured from the Dakota gasification facility in North Dakota. But Boundary Dam's frequent equipment failures meant that Unit 3 was unable to meet the contractually obligated sales of CO2 to Cenovus, the operator of the Weyburn oil field.[85] By the end of 2015, SaskPower owed 12 million CAD ($9 million USD) to Cenovus for failing to deliver promised CO2 for EOR.[86] In 2016, SaskPower had to renegotiate its contract with Cenovus to avoid a $91 million (CAD) failure to deliver penalty.[87] Ultimately, Boundary Dam Unit 3 was unable to provide CO2 at the prevailing market price of $25/MT.[88] The renegotiated price resulted in Cenovus paying the market rate for CO2, while the plant's high operating costs remained the same.

Even regions that lacked access to large natural deposits and industrial sources of CO2 could not justify sourcing CO2 from coal projects for EOR operations. At Plant Barry, captured CO2 was piped 12 miles and sequestered in a geologic formation in the Citronelle Oil Field above an active CO2-EOR pilot operation.[89] Although captured CO2 from Unit 5 was not used in CO2-EOR, Plant Barry's operators planned to scale the CCS facility to capture and commercialize one MT of CO2 emissions by selling captured CO2 to CO2-EOR operations in the Citronelle oil field.[90] These plans never materialized due in part to the poor regional economics of sourcing CO2 from flue gas emissions. Petra Nova originally planned to supply enough cheap CO2 to revitalize Hilcorp's West Ranch Oil Field. But when the plant was operating, Petra Nova did not supply enough CO2 to sustain EOR operations.[91] The cost of its CO2 was estimated at $60/tonne.[92] When oil prices collapsed in 2020, operators could no longer afford to purchase Petra Nova's expensive and unreliable CO2.

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[85] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.
; ***EO 12866_GHG EGU New Sources 2060-AT56 TSD Reliability of Currently Available CCS Final Rule_20201214***, the Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, December, 2020.

[86] Fraser, D.C. **SaskPower renegotiated contract to avoid $91.8M penalty**, Regina Leader-Post, June 13, 2016;

[87] The Canadian Press. **SaskPower pays out $12M to Cenovus for not providing captured carbon dioxide**. CTV News, October 26, 2015.

[88] Geoff Leo, **Carbon Capture plant Delay Costing SaskPower Millions**, CBC News, October 26, 2015.

[89] U.S. Department of Energy, **Alabama Injection Project Aimed at Enhanced Oil Recovery, Testing Important Geologic CO2 Storage**, Office of Fossil Energy and Carbon Management, March 1, 2010.

[90] Richard A. Esposito, Jack C. Pashin, Denise J. Hills, Peter M. Walsh, "**Geologic assessment and injection design for a pilot CO2-enhanced oil recovery and sequestration demonstration in a heterogeneous oil reservoir: Citronelle Field, Alabama, USA**" *Environmental Earth Science*, Volume 60, (March 2010) p. 431-444; Konstantinos Theodorou, **Carbon Dioxide Enhanced Oil Recovery from the Citronelle Oil Field and Carbon Sequestration in the Donovan Sand, Southwest Alabama**, dissertation, the University of Alabama at Birmingham, 2013; **Plant Barry Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 23, 2023); **Southeast Regional Carbon Sequestration Partnership Citronelle Project**, NETL.DOE.gov (Last visited June 23, 2023); **Operations Initiated at Southern Company's Carbon Capture Project**, EnergyOnline.com (Last visited June 23, 2023).

[91] Florian Martin, **Low Oil Prices Lead to Shutdown of Much-Hyped Carbon Capture System Outside Houston**, Houston Public Media, August 3, 2020.

[92] Dennis Wamsted and David Schlissen, **Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant Is a Warning Sign**, Institute for Energy Economics and Financial Analysis, August 2020.

Petra Nova, Boundary Dam's Unit 3, and the cancellation of Plant Barry, are prime examples of flue gas captured CO_2's failure to deliver CO_2 at a competitive price to EOR operations. By the DOE's own estimates, the cost of capturing CO_2 from flue gas needs to decline by 50 percent.[93] Even these estimates are likely pollyannish. To spur investment in CCS technology the IRA has significantly increased the 45Q tax credit. Congress has increased the 45Q tax credit for CO_2 sequestered through CO_2-EOR by more than 70 percent, from $35/tonne to $60/tonne, to match what the DOE believes is the break-even price.[94] There is no guarantee that these tax credits will continue, but as all CCS plants have shown, without them, CCS is not economically feasible.

The EPA has proposed several methods of permanent geological sequestration that require a massive and costly build out of a CO_2 midstream infrastructure and unproven methods of geological sequestration. For example, the EPA recommends disposing of captured CO_2 by injecting it into coal seams even though it recognizes that this process remains theoretical and has not been tested.

The EPA's BSER tacitly promotes squandering financial resources pursuing the uneconomical development of CO_2 capture facilities that will never have a positive return on investment. Should Congress decide to repeal these tax credits, all CCS coal and natural gas projects will lose their only stream of reliable revenue as their captured emissions will never be able to compete with CO_2 sourced from natural deposits or industrial sources.

e. Discount Rate.

Discounting future benefit streams and compliance costs is an integral part of any benefit-cost analysis. In the net present value model, discount rates estimate the value of money received in the future by converting its value into dollars. It is important for regulators to accurately and consistently discount future benefits received and costs stemming from a regulation, so that policy makers have a complete picture.[95] In the proposed rule, the EPA properly discounted future benefits and compliance costs using the Office of Management and Budget (OMB) Circular A-4's prescribed real discount rates of 3 percent and 7 percent. But the EPA calculated the social cost of greenhouse gases (SC-GHGs) and compliance costs using much lower discount rates. These estimates were obtained using integrated planning models (IMPs) that fail to meet OMB A-4's threshold for being "sound and defensible."[96] The EPA used an IMP to calculate the social cost of carbon at five, three, and 2.5 percent at the 95th percentile of environmental damages. For calculating compliance costs, the EPA used one real discount rate of 3.76 percent.[97] The EPA's bifurcated discount rates grossly understate the private sector's compliance costs and vastly

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93 Ryser, Jeffrey. **DOE hopes to see carbon capture costs cut 50%; NETL says it has stored 10 million mt of CO_2**. S&P Global, June 10, 2020.

94 **Section 45Q Credit for Carbon Oxide Sequestration**, International Energy Agency, April 14, 2023.

95 David C. Tryon, Alex M. Certo, Zachary D. Cady, and Trevor W. Lewis, **Comment on Proposed OMB Circular A-4**, The Buckeye Institute, June 6, 2023.

96 **OMB Circular A-4**, Regulatory Analysis, September 17, 2003.

97 U.S. EPA, **Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units… and Repeal of the Affordable Clean Energy Rule**, May 23, 2023.

overestimate the future benefits stream. This is unsurprising considering that federal agencies routinely and significantly understate the cost of their regulations.[98]

The three discount rates selected by the interagency working group (IWG) in 2010 centered around the 3 percent estimate of the consumption interest rate published in OMB's Circular A-4 in 2003. That guidance was based on the real rate of return on 10-year Treasury Securities over the prior 30 years (1973 through 2002), which averaged 3.1 percent. Over the past four decades there has been a substantial and persistent decline in real interest rates driven by decreases in the equilibrium real interest rate (Bauer and Rudebusch 2020).

OMB A-4's guidelines for regulatory analysis instruct regulators to "monetize quantitative estimates whenever possible… [by using] sound and defensible values or procedures… and ensure that key analytical assumptions are defensible."[99] The EPA and the IWG have used several integrated planning models to obtain the SC-GHGs. But the IPMs used are so inconsistent in calculating values that results are neither sound nor defensible.

Dr. Kevin Dayaratna, Chief Statistician at the Heritage Foundation, has demonstrated that the models the EPA used to estimate various SC-GH fail to produce consistent and reliable results.[100] When Dr. Dayaratna put the real discount rate of 7 percent into the IPMs, he found that the SC-GHG declines substantially and is even positive in some cases – implying that greenhouse gas emissions carry positive societal benefits. The EPA's IPM's inability to produce a consistent SC-GHG at higher discount rates implies that the models undergirding the IPMs are indefensibly inconsistent, and the derived results should be considered unsound.[101] And the EPA's inconsistent discounting treatment is not limited to estimating the SC-GHG. When discounting compliance costs of adopting CCS at fossil fuel-fired EGUs in the IPM, the EPA selected a single discount rate - 3.78 percent, well below the seven percent required by OMB A-4. Given the numerous mechanical and economic challenges encountered by Boundary Dam, Petra nova, and the Kemper Project, discounting at 3.78 percent is wholly inappropriate and vastly understates the financial risk of CCS retrofits and new fossil fuel-fired power plants. The EPA's inconsistent handling of discount rates within its own planning models should cast doubt on the empirical results presented in the benefit-cost-analysis.

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[98] Casey B. Mulligan, **Burden is Back: Comparing Regulatory Costs between Biden, Trump, and Obama**, June 2023 (estimating EPA's 2021 rule for light-duty vehicle emissions at "a cost of $309 billion, which is about 70 percent more than the EPA reported").
[99] **OMB Circular A-4**, Regulatory Analysis, September 17, 2003.
[100] Kevin Dayaratna, **Why "Social Cost of Carbon" Is the Most Useless Number You've Never Heard of**, The Heritage Foundation, March 2, 2021; Kevin Dayaratna and David Kreutzer, **Unfounded FUND: Yet Another EPA Model Not Ready for the Big Game**, Heritage Foundation, April 29, 2014; Kevin Dayaratna and David Kreutzer, **Loaded DICE: An EPA Model Not Ready for the Big Game**, November 21, 2013; Patrick J. Michaels and Kevin D. Dayaratna, **The Scientific Case for Vacating the EPA's Carbon Dioxide Endangerment Finding: The Hazard of Unreliable Models Guiding Policy**, Competitive Enterprise Institute, Issue Analysis No. 3, April 17, 2020.
[101] Kevin Dayaratna and David Kreutzer, **Unfounded FUND: Yet Another EPA Model Not Ready for the Big Game**, Heritage Foundation, April 29, 2014; Kevin Dayaratna, **Why "Social Cost of Carbon" Is the Most Useless Number You've Never Heard of**, Heritage Foundation, March 2, 2021.

f. Conclusion: The Proposed BSER for Long-Term Coal-Fired EGUs is Arbitrary, Capricious, and an Abuse of Discretion.

The EPA's proposed BSER and Section 111(d) standard fail the arbitrary, capricious, and abuse of discretion test.

First, in determining that CCS is the BSER, the proposed rule relied on the fact that forcing plants to implement CCS would advance the development of CCS technology. This is a factor "which Congress has not intended [the agency] to consider."[102] Second, the proposed rule "offered an explanation for its decision that runs counter to the evidence before" it.[103] The EPA's own sources confirm that its examples of "successful" CCS facilities have entirely failed to achieve a consistent capture rate at a level that satisfies the proposed standard. Third, the proposed rule ignores the GAO reports demonstrating the infeasibility of the CCS facilities, and thus "it ignores important considerations or relevant evidence" without justification.[104] Fourth, the proposed rule's convoluted explanation for its exemplar CCS facilities has not "reasonably considered the relevant issues and reasonably explained the decision."[105] Fifth, discounting compliance costs at 3.8 percent runs counter to evidence showing that CCS facilities do not work on a large scale.[106] All of the EPA's examples of "successful" CCS facilities had significant difficulties implementing CCS and the EPA must account for those difficulties at all other regulated plants. This implies that retrofitting existing power plants with CCS facilities puts immense financial risk on the power plant operator to comply with the regulation and warrants the use of a higher discount rate when estimating compliance costs in the IPM. Sixth, the water use impact analysis runs counter to the evidence and does not consider the additional water needed for CCS. The EPA's unilateral dry cooling solution to the extra water problem does not adequately account for hot or dry environmental constraints. Seventh, the only CCS facilities that have had even limited success were linked to CO_2-EOR operations, and the EPA's other proposed solutions of geologic sequestration, mass scale saline formation, and coal-seam injection remain theoretical. Finally, the proposed rule risks successful legal challenges because the EPA "entirely failed to consider an important aspect of the problem,"[107] namely, that CCS is only viable with DOE grants and subsidies. If Congress or the DOE eliminate these grants and subsidies, the proposed rule will shutter power plants.

Not only is the proposed rule's BSER an unproveable system, but the section 111(d) standard is based on a capture rate that has never been consistently achieved at scale. Thus, state plans must

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[102] *State Farm Mut. Auto. Ins. Co.*, 463 U.S. at 43; 42 U.S.C. § 7411 (CAA 111(a)(1)) ("the best system of emission reduction [ ] (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) . . . .").
[103] See BNSF Ry. Co. v. Fed. R.R. Admin., 62 F.4th 905, 910 (5th Cir. 2023).
[104] *Rancheria v. Jewell*, 776 F.3d 706, 714 (9th Cir. 2015)
[105] *Abbott v. Biden*, No. 22-40399, 2023 WL 3945847, at *5 (5th Cir. June 12, 2023).
[106] Genuine Parts Co. v. Env't Prot. Agency, 890 F.3d 304, 313 (D.C. Cir. 2018) ("It was arbitrary and capricious for EPA to rely on portions of studies in the record that support its position, while ignoring cross sections in those studies that do not.").
[107] *State Farm Mut. Auto. Ins.*, 463 U.S. at 30.

adopt a system that does not work or force power plants to shut down as there is no alternative to meet the standard. As the U.S. Supreme Court noted in *West Virginia v. EPA*, "[o]f course, EPA has never ordered anything remotely like that, and we doubt it could."[108]

IV. The Proposed Standard for Non-continental Gas- and Oil-fired Power Plants Risks Electricity Crises in Hawaii.

The EPA has requested comment on section XII.D.1.b.vi, non-continental intermediate and baseload oil-fired power, "that is defined by 0 to 2 standard deviations in annual emission rate (using the 5-year period of data) above the baseline emission performance, or that is 0 to 10 percent above the baseline emission performance."[109] Any regulation on non-continental oil-fired power plants will decrease dispatchable baseload power generation and substantially raise electricity rates in Hawaii, which will disproportionately impact Hawaii's poor and indigenous populations.

To avoid causing a supply and affordability crisis in Hawaii, the EPA should set no emissions limitation for non-continental oil-fired baseload and intermediate power stations. Over 80 percent of Hawaii's electric power is generated by oil-fired power plants.[110] Although Hawaii has prime geography for including some renewable power sources into its energy mix,[111] its distance from the mainland and the Merchant Marine Act of 1920 have raised the cost of building renewable energy sources and stalled the state's energy transition, leaving oil-fired power as the only reliable energy source for meeting existing and growing electric power demand for the foreseeable future.

Having a single reliable energy source puts Hawaii's grid in a precarious condition and means that even small reductions in generation capacity can raise electricity prices dramatically. In September 2020, for example, Hawaii's legislature passed Senate Bill 2629, requiring Hawaii's only coal plant on Oahu to shut down by 2022.[112] The plant complied and electricity prices immediately increased seven percent as the supply of baseload power declined and was replaced with more expensive oil-fired power plants.[113]

Hawaii has tried to fill the gap in power generation with lithium battery packs to store energy generated by the limited renewable infrastructure. But Hawaiian power companies estimate only 30 percent of the battery's energy will come from renewables, with the rest derived from oil-fired power.[114] Setting an emission limit on Hawaii's dominant source of electricity for baseload and

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[108] *W. Virginia v. EPA*, 142 S. Ct. 2587, 2612 n. 3 (2022).
[109] U.S. Environmental Protection Agency, **New Source Performance… and repeal of the Affordable Clean Energy Rule**, May 23, 2023.
[110] U.S. Energy Information Administration, **US Energy Atlas with Total Energy Layers** (Last Visited: Jun 26, 2023).
[111] U.S. EIA, **Hawaii Profile Analysis**, March 16, 2023.
[112]U.S. EIA, **Hawaii Profile Analysis**, March 16, 2023; **Electricity Generation; Coal; Prohibition**, 2020(Hawaii S.B. No. 2629), Act 23.
[113] Jason Lindquist, **Can't Help Falling In Love - Hawaii Finds The Move Away From Fossil Fuels Is Easier Said Than Done**, RNB energy, June 1, 2023.
[114] *Ibid*.

peak generation while the state struggles with its energy transition will condemn Hawaiians to higher electricity rates. As studies have shown, higher electricity rates are an inequitable, regressive tax that falls disproportionately hard on the poor.[115] The higher electricity prices will hurt Hawaii's indigenous community the most, 15.5 percent of whom live in poverty.[116] The proposed rule increases the cost of electricity primarily—and unjustly—on low-income and indigenous Hawaiians.

The EPA should delay indefinitely setting emission limitations on non-continental oil-fired power plants. More importantly, the EPA should learn from Hawaii's misguided decision to forcibly close its last coal-fired plant and recognize the crises that follow when regulators artificially curb coal- and gas-fired generators.

V. The Proposed Standard for Baseload Natural Gas Plants Will Exacerbate an Electricity Crisis.

The EPA's proposed "BSER of routine methods of operation and maintenance and a degree of emission limitation of no increase in emission rate" will handicap fossil fuel powered operators to expand capacity to meet America's growing energy consumption needs. Additionally, existing natural gas plants will need to adopt either CCS technologies or low-greenhouse gas (GHG) hydrogen by 2035. The EPA's proposed inclusion of energy attribute certificates to certify low-GHG hydrogen is yet another arbitrary regulatory deterrent for utilities to expand natural gas generated electricity. Complying with these BSERs risks exacerbating an impending energy security crisis by dissuading investment in reliable and dispatchable baseload power and encouraging utilities to adopt intermittent sources of renewable electricity.

Capping the emissions rate at natural gas power plants, America's leading source of low-carbon energy, places an artificial limitation on expanding America's leading source of affordable power. Requiring future sources of natural gas to use hydrogen co-firing will increase the cost of residential electricity as existing plants will need costly retrofits and an expensive hydrogen midstream infrastructure. Additionally, most hydrogen is produced as a byproduct of natural gas refining. Hydrogen produced through electrolysis is only as clean as the energy used to produce it. CCS is not economically viable at natural gas plants due to the low concentrations of CO2 in the flue gas.[117]

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[115] Rea S. Hederman Jr., Michael E. Reed, and Trevor Lewis, ***The Economic Impact of A Potential New Clean Power Plan on Ohio and California***, The Buckeye Institute, April 12, 2023; F. Noel Perry, Colleen Kredell, Marcia E. Perry, Stephanie Leonard, **Paying for Electricity in California, How Residential Rate Design Impacts Equity and Electrification**, Next10, September 22, 2022.

[116] ***Demographic, Social, Economic, and Housing Characteristics for Selected Race Groups in Hawaii***, Research and Economic Analysis Division of the Department of Business, Economic Development & Tourism, March, 2018.

[117] Kazuya Goto, Katsunori Yogo, Yakyuki Higashii, "**A review of efficiency penalty in a coal-fired power plant with post-combustion CO2 capture**" Applied Energy, Volume 11 (November 2013) p. 710--720.

On May 4, 2023, four Federal Energy Regulation Commission (FERC) commissioners told the Senate Committee on Natural Resources and Energy that America was headed for an electricity reliability crisis.[118] Commissioner Mark Christie summarized the causes of the crisis as follows:

> The core of the problem is this: Dispatchable generating resources are retiring far too quickly and in quantities that threaten our ability to keep the lights on. The problem generally is not the addition of intermittent resources, primarily wind and solar, but the far too rapid subtraction of dispatchable resources, especially coal and gas.[119]

Coal accounts for nearly 20 percent of all electric power generated in America. When West Virginia Senator Joe Manchin asked the commissioners if America's power grid could maintain reliability if coal "pulled . . . off right now," all four commissioners agreed that it could not.[120] And removing coal from the national grid overnight would especially impact regions that depend heavily on coal for electric power. Appalachian states, like West Virginia and Kentucky, depend on coal for more than 65 percent of their electric power.[121] As Commissioner James Danly commented: "it is simply impossible to keep the system running entirely with unreliable intermittent generation."[122] Yet, the EPA's proposed rule would do exactly that by capping emissions at fossil fuel-fired power plants and pigeonholing future power generation to solely intermittent renewable sources.

Natural gas is cheaper and burns cleaner than coal, and replacing coal with natural gas could reduce power plant emissions in Appalachia's coal country. But limited pipeline capacity prevents that from happening. As Wyoming Senator John Barrasso observed during the May 4, testimony, "[i]n 2022, the least interstate natural gas pipeline capacity was added since [the energy information administration] began data collection in 1995."[123] Last year, the United States added a mere 897 million cubic feet per day of permanent interstate pipeline capacity from just five pipeline projects.[124] Permitting delays and cancelations have prevented large parts of the West Coast, New England, and Midwest, from accessing cheap natural gas. Expanding pipeline capacity would not only facilitate coal country's transition to cheaper natural gas, but it would also reduce methane emissions at wellheads. As FERC Commissioner Christie observed, expanding pipeline capacity is crucial for replacing shuttering coal plants: "We are not building a transportation capacity for gas units. Gas units increasingly are the ones that were being called upon to be the balancing resources when coal is retired prematurely, but if you can't get gas to the generating

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[118] U.S. Congress, Senate, Committee on Energy and Natural Resources, ***Full Committee Hearing to Conduct Oversight of FERC***. 118th Cong., 1st sess., May 4, 2023.
[119] ***Full Committee Hearing to Conduct Oversight of FERC***: **Testimony before the Committee on Energy and Natural Resources**, 118th Cong. (2023) (statement of Mark C. Christie, FERC commissioner).
[120] *Ibid.*
[121] Nikos Tsafos, **Phasing Out Coal from U.S. Electricity Increasingly a Regional Challenge**, CSIS, May 24, 2021.
[122] U.S. Congress, Senate, Committee on Energy and Natural Resources, ***Full Committee Hearing to Conduct Oversight of FERC***. 118th Cong., 1st sess., May 4, 2023.
[123] *Ibid.*

units, they can't run."[125] But the proposed rule's errant restrictions on emissions from natural gas fired power plants hinder the expansion of natural gas pipelines, ironically hindering expediting decarbonization of several regions living in energy isolation. Renewable power will not be able to meet these regional energy needs without natural gas generation. And without a cheap replacement for coal-fired electricity, Americans will pay more for the energy they consume.

Conclusion

The EPA has failed to adequately demonstrate CCS technology as a BSER for emission reduction under the CAA and fails Section 111(d)'s legal standard. The proposed rule leaves coal plant operators with functionally one option: shut down before 2040. The EPA's unwelcomed restrictions on natural gas risk dissuading investment in a cheap source of low-cost energy and pigeonholing producers into adopting expensive and unreliable intermittent sources of renewable power. States that have overbuilt renewable sources of power, like Texas and California, have had problems balancing power demand and power supply. This has led to power shortages, greater risk of brown- and blackouts, and households paying expensive surge prices for electricity. In its current form, the EPA's proposed rule promotes an unsustainable energy policy.

[125] *Ibid.*

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