State of West Virginia
Office of the Attorney General
Patrick Morrisey
Attorney General

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Michael S. Regan
Administrator, Environmental Protection Agency
1200 Pennsylvania Ave NW, Suite 1101A
Washington, DC 20460

Submitted Electronically via Regulations.gov

Re: Comments on the Proposed Rulemaking Titled "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" by the Attorneys General of the States of West Virginia, Alabama, Arkansas, Georgia, Idaho, Indiana, Iowa, Kentucky, Louisiana, Mississippi, Missouri, Montana, Nebraska, New Hampshire, Ohio, Oklahoma, South Carolina, South Dakota, Texas, Utah, and Virginia (Docket No. EPA-HQ-OAR-2023-0072)

Dear Administrator Regan:

We appreciate the opportunity to comment on EPA's proposed Section 111 rule for existing coal-, natural-gas-, and oil-fired power plants. *See New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 88 Fed. Reg. 33,240 (May 23, 2023). As States, we take seriously both our traditional authority in energy regulation and our statutory role within the Clean Air Act's cooperative-federalism framework. And in discharging those responsibilities, we aim to secure reliable, affordable, and environmentally responsible energy for everyone. But we write because the Proposed Rule undermines that goal.

Only a year ago, the Supreme Court held that EPA cannot use Section 111 of the Clean Air Act to reshape the nation's electricity grids. *See generally West Virginia v. EPA*, 142 S. Ct. 2587 (2022). The Court concluded that EPA's effort to mandate "generation-shifting" brought about "an enormous and transformative expansion in EPA's regulatory authority" that Congress had never approved. *Util. Air Regul. Grp. v. EPA ("UARG")*, 573 U.S. 302, 324 (2014). *West Virginia* made plain that EPA cannot rely on Section 111(d) to "demand much greater reductions in emissions" based on its belief "that it would be 'best' if coal [and other fossil fuels] made up a much smaller share of national electricity generation." *West Virginia*, 142 S. Ct. at 2612.

The Proposed Rule at least abandons the more direct "generation-shifting" mandate that the Court rejected in *West Virginia*—but it still doubles down on the earlier rule's goals by setting unrealistic standards. If finalized, EPA's impossible proposal will leave coal- and natural-gas plants with no other option but to close. Yet EPA has no more authority to mandate this result indirectly than it did when it tried to do so directly. Thus, the Proposed Rule exceeds EPA's authority by forcing the kinds of major shifts that *West Virginia* already said can't be imposed by way of Section 111(d).

Other problems plague the Proposed Rule. For instance, the statute also forbids EPA's attempt to remove States' textually protected discretion to tailor individual performance standards for the power plants within their borders. It similarly bars "best" systems of emission reduction, like the two EPA proposes here, that lack any real-world indicia of success. And if the Clean Air Act's specific limits were not enough, general principles of reasoned decision-making also require EPA to set aside an astronomically costly rule that will make energy dangerously unreliable nationwide.

We urge EPA to reconsider.

BACKGROUND

Section 111(d) of the Clean Air Act should be cooperative federalism at its best. In it, Congress directed EPA to name "categories of stationary sources" that "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A). A stationary source is "any building, structure, facility, or installation which emits or may emit any air pollutant"—including power plants. *Id.* § 7411 (a)(3). After EPA lists a source category, it must "publish proposed regulations, establishing Federal standards of performance for new [and modified] sources within" that category. *Id.* § 7411(b)(1)(b). The CAA defines "standard of performance" as:

> [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.

Id. § 7411(a)(1). This provision directs EPA to "determine, taking into account various factors, the best system of emission reduction which has been adequately demonstrated" (BSER) and "impose an emissions limit on new stationary sources that reflects" "the degree of emission limitation achievable through the application of the [BSER]." *West Virginia v. EPA*, 142 S. Ct. 2587, 2601 (2022) (cleaned up). Sources can generally satisfy the "emissions cap any way" they choose. *Id.*

After the EPA sets the standard for new and modified sources, it promulgates guidelines under Section 111(d) for States to submit plans setting the standard of performance for existing sources; even then, it issues those guidelines "only if [the sources] are not already regulated under" Sections 110 or 112. *West Virginia*, 142 S. Ct. at 2601. In this way, Section 111(d) "operates as a gap-filler, empowering EPA to regulate harmful emissions not already controlled under the Agency's other authorities." *Id.* (cleaned up). EPA again determines "the best system of emission reduction that has been adequately demonstrated for existing covered facilities." *Id.* at 2602 (cleaned up). But then States take over: They "submit plans containing the emissions restrictions that they intend to adopt and enforce" that reflect application of the EPA-set BSER. *Id.*

For several decades, EPA rarely deployed Section 111(d). When it exercised that power, it established a BSER through source-specific technologies and operating procedures. Things changed, however, when EPA finalized the Clean Power Plan (CPP) in October 2015. Rather than determining the BSER for existing coal power plants based on emission reductions that could be achieved at individual plants, EPA chose a novel BSER in the form of "generation shifting from higher-emitting to lower-emitting" producers of electricity. *West Virginia*, 142 S. Ct. at 2603 (quoting 80 Fed. Reg. 64,662, 64,728 (Oct. 23, 2015)). And it identified three ways a regulated plant operator could shift generation to the sources EPA preferred: reducing electricity generation; building a new natural-gas plant, wind farm, or solar installation; or purchasing emission allowances or credits as part of a cap-and-trade regime. *West Virginia*, 142 S. Ct. at 2603.

EPA set the standards so low that it was impossible for existing plants to comply using any current technologies or process improvements. The result was that EPA was effectively mandating a shift in what sources comprise the nation's power grids: EPA set the BSER so that by 2030, coal would provide "27% of national electricity generation, down from 38% in 2014." *West Virginia*, 142 S. Ct. at 2604. In short, the BSER was "one that would reduce carbon pollution mostly by moving production" to different sources, not one that would reduce emissions from the existing sources themselves. *Id.* at 2603. This BSER aimed to substitute one source of power generation for another—"to compel the transfer of power generating capacity from existing sources to wind and solar." *Id.* at 2604.

All this reorienting would have come at a significant cost. EPA admitted that the CPP would "entail billions of dollars in compliance costs (to be paid in the form of higher energy prices), require the retirement of dozens of coal-fired plants, and eliminate tens of thousands of jobs across various sectors." *West Virginia*, 142 S. Ct. at 2604 (citing EPA, REGULATORY IMPACT ANALYSIS FOR THE CLEAN POWER PLAN FINAL RULE 3-22, 3-30, 3-33, 6-24, 6-25 (2015), *available at* https://bit.ly/43SlgeT). Of course, the States most dependent on fossil-fuel-fired energy sources would have borne the brunt of the costs.

But the CPP never went effect because the Supreme Court granted a stay pending review. *West Virginia v. EPA*, 577 U.S. 1126 (2016). And EPA eventually repealed the CPP, concluding that the rule had "significantly exceeded" the agency's statutory authority. 84 Fed. Reg. 32,520, 32,523 (July 8, 2019). Specifically, EPA agreed that it never should have considered generation shifting as part of the BSER. Both Section 111's plain text and the major questions doctrine supported its revised determination, it explained, because the "generation-shifting scheme was projected to have billions of dollars of impact," and "no section 111 rule of the scores issued ha[d] ever been based on generation shifting." 84 Fed. Reg. at 32,529. EPA thus concluded that it had lacked the authority to implement the CPP because Congress did not provide a clear statement showing "[c]ongressional intent to endow the Agency with discretion of this breadth." *Id.* EPA then replaced the CPP with a different Section 111(d) rule. 84 Fed. Reg. at 32,532. That rule confirmed that a BSER should apply to specific facilities rather than at a regional or grid-wide level.

The second rule didn't go into effect either because many States and private parties filed petitions for review in the D.C. Circuit. That Court ultimately held in a 2-1 decision that EPA's "repeal of the Clean Power Plan rested critically on a mistaken reading of the Clean Air Act." *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 995 (D.C. Cir. 2021). The majority read Section 111 broadly—finding that EPA "tied its own hands" by focusing on only source-specific BSERs, *id.* at 962 n.9, and that "Congress imposed no limits on the types of measures the EPA may consider," *id.* at 946.

Last year, though, the Supreme Court reversed the D.C. Circuit, holding that EPA had been right—the second time—to reject the CPP because EPA lacked authority to require "generation shifts." *West Virginia*, *supra*. The Court noted that EPA had historically considered "measures that improve the pollution performance of individual sources" and followed a "technology-based approach" in identifying systems of emission reduction. *Id.* at 2611, 2615. But EPA abandoned that practice with the CPP, as it focused on generation shifting that would "substantially restructure the American energy market." *Id.* at 2602, 2610. The CPP was an "extraordinary case[] in which the history and the breadth of the authority that the agency ha[d] asserted, and the 'economic and political significance' of that assertion, provide[d] a reason to hesitate before concluding that Congress meant to confer such authority." *Id.* at 2608 (cleaned up). And EPA's claim of an "unheralded power representing a transformative expansion in its regulatory authority in the vague language of a long-extant but rarely used statute—one designed as a "gap filler"—meant that the major questions doctrine applied. *Id.* at 2610 (quoting *UARG*, 573 U.S. at 324).

The Court thus explained that EPA needed to "point to 'clear congressional authorization' to regulate in that manner." *West Virginia*, 142 S. Ct. at 2614 (quoting *UARG*, 573 U.S. at 324)). It couldn't: The Court found that EPA failed to show any authority establishing that the "best system of emission reduction" identified by EPA in the CPP was within the clear authority that Congress delegated in Section 111. *West Virginia*,142 S. Ct. at 2614-15. Lacking any clear statutory authority for "[a] decision of such magnitude and consequence," the Court reversed and let the CPP repeal go into effect. *Id.* at 2616.

So the Court barred EPA from adopting expansive regulations under Section 111 that would require existing power plants to engage in generation shifting. True, the Court noted that it had "no occasion to decide whether the statutory phrase 'system of emission reduction' refers *exclusively* to measures that improve the pollution performance of individual sources." *West Virginia*, 142 S. Ct. at 2615 (emphasis in original). But the decision's logic forecloses other regulatory efforts that re-interpret Section 111 in new and expansive ways—especially when they involve questions of vast "economic and political significance" that Congress could not have anticipated. *Id.* at 2623 (Gorsuch, J., concurring).

Moving ahead a year from *West Virginia v. EPA*, this Proposed Rule does exactly that. EPA is proposing two BSERs for fossil-fuel-fired plants: carbon capture and storage/sequestration (CCS) and hydrogen co-firing.[1]

CCS involves rerouting flue gas (exhaust from the electric generating unit), cooling it, and passing it through some kind of agent (like a solvent or membrane), which isolates the carbon while letting the rest of the flue gas escape. The carbon is then extracted from the agent and collected, often offsite. It is then transported somewhere else for use or long-term storage. EPA proposes that all baseload natural-gas-fired plants—that is, those operating at least at 50%—begin operating CCS systems at a 90% capture rate by 2035. 88 Fed. Reg. at 33,244. The Proposed Rule would also require all coal-fired plants without pre-2040 retirement dates to begin operating CCS systems at a 90% capture rate by 2030. *Id.* at 33,359.

For natural gas sources, EPA also proposes an alternative BSER, hydrogen co-firing. Co-firing involves adding pure hydrogen to a combustion turbine to reduce carbon emissions. Today, combustion turbines run on natural gas—though in rare circumstances operators will add a small amount of pure hydrogen. EPA proposes requiring ultra-low-GHG hydrogen at 30% by 2032 for all intermediate and baseload plants, and at 96% by 2038. 88 Fed. Reg. at 33,244.

At first blush, these new BSERs might appear to be a move away from a CPP-style generation-shifting scheme. Unfortunately, they are not. The Proposed Rule sets impossible BSERs that the industry has no chance of meeting. It would force plants to close and compel a switch to lower-emitting fuel sources such as wind and solar—making it a de facto generation-shifting mandate. So in much the same way the CPP did, this Proposed Rule exceeds EPA's delegated authority.

DISCUSSION

Last year, the Supreme Court rejected a BSER based on grid-wide production shifts because it was "an unheralded power representing a transformative expansion in [EPA's] regulatory authority." *West Virginia*, 142 S. Ct. at 2610 (cleaned up). But here we are again. The Proposed Rule bears the hallmarks of EPA's failed generation-shifting attempt. Again, EPA relies on an obscure, seldom used CAA provision to adopt an unprecedented regulation that will force a sector-wide shift in electricity production from coal and natural gas to other sources EPA thinks would better advance its policy goals. Rather than learning from *West Virginia*, this proposal doubles down on the CPP's mistakes—targeting coal and natural-gas plants for effective elimination. But that's a decision major enough for only Congress to make. And just like a year ago, the statutory text contains no clear statement showing that Congress made that call, much less tasked EPA with carrying it out.

[1] EPA is proposing six BSERs total: three for coal-fired boilers, depending on the plant's retirement date and capacity factor; one for natural-gas and oil-fired boilers; and two for natural gas combustion turbines, depending on their capacity factor. This comment letter focuses on the primary BSERs of CCS for coal and natural gas plants and co-firing for natural gas plants.

The Proposed Rule also fails under the text that *is* found in Section 111. EPA proposes two BSERs: CCS and hydrogen co-firing. But at least for now and into the near future, both are more fiction than science. Neither CCS nor co-firing hydrogen is used at utility-scale power plants in the United States, and it looks like technological limitations will prevent them from ever being widely implemented. To the extent that either technology is in limited use today, each is prohibitively expensive and faces myriad operational, transportation, and infrastructure problems. So plants won't be able to meet emissions standards premised on these impossible-to-implement BSERs. And because EPA appears to know this, it seems the Proposed Rule strives to get at the CPP's ends through another route. EPA's proposal also comes with serious unintended consequences—for example, destabilizing the energy grid at a time when demand for electricity is only increasing. All these problems mean CCS and hydrogen co-firing flunk the CAA's requirements for an "adequately demonstrated" BSER, and the Administrative Procedure Act's requirements for rational rulemaking. EPA should withdraw the Proposed Rule.

I. The Proposed Rule Violates *West Virginia v. EPA* And Exceeds EPA's Delegated Authority.

The Proposed Rule comes dressed in new clothes. But despite leaving 2015's fashions behind, it still covers an attempt to remake the nation's electricity-generation sector without clear congressional authority to take up that major task.

A. By Forcing Generation Shifting, The Proposed Rule Meddles With The Same Major Questions As Before.

A little over a year ago, the Supreme Court considered what Congress meant when it delegated EPA power to designate a "best system of emission reduction that the Agency has determined to be adequately demonstrated" for a category of stationary sources. *West Virginia*, 142 S. Ct. at 2599 (cleaned up). Noting "the ancillary nature of Section 111(d)," the Court explained that EPA had used the provision "only a handful of times since the enactment of the statute in 1970." *Id.* at 2602. And in those few pre-2015 cases, EPA had "always" looked to "measures that would reduce pollution by causing plants to operate more cleanly." *Id.* at 2599; *see also* 41 Fed. Reg. 48,706 (Nov. 4, 1976) (fiber mist eliminators installed on sulfuric acid production units); 56 Fed. Reg. 5,514 (Feb. 11, 1991) (spray dryers or dry sorbent injection); 61 Fed. Reg. 9,905 (Mar. 12, 1996) (control devices to reduce non-methane organic compounds); 62 Fed. Reg. 48,438 (Sept. 15, 1997) (scrubbers and waste disinfection technologies); 70 Fed. Reg. 28,606 (May 18, 2005), vacated by *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008) (flue gas desulfurization systems and selective catalytic reduction).

Section 111 was noteworthy to the Court for what it did not say. Consistent with EPA's decades-settled practice, the statute did not give the agency power to decide which sources should comprise the nation's power grids or how much or how little power different types of power plants should produce. The Court saw "every reason to 'hesitate before concluding that Congress' meant to confer on EPA" authority like that. *West Virginia*, 142 S. Ct. at 2610 (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159-60 (2000)). Doing so would have read too much into "merely plausible" interpretations of "vague language," allowing the agency to adopt an "unheralded" and "transformative expansion" of its delegated powers. *West Virginia*, 142 S. Ct. at 2610 (cleaned up).

So when EPA tried to read Section 111 that way anyway—making major policy judgments in the CPP rule about the ideal composition of our energy fleets and how large a shift from coal and natural gas the grids could tolerate—the Court said no. Decisions like those ones "rest[] with Congress itself, or an agency acting pursuant to a clear delegation from that representative body." *West Virginia*, 142 S. Ct. at 2616. In short, the power EPA tried to assume had all the hallmarks of a major question. Answering whether EPA could "force a nationwide transition away from the use of coal to generate electricity," *id.*, was no "ordinary case," *id.* at 2608. The "history and the breadth of the authority that the agency has asserted, and the economic and political significance of that assertion," said EPA could not tackle that issue unilaterally. *Id.* (cleaned up). Resolving the case therefore required a "different approach" in which EPA had to "point to clear congressional authorization for the power it claim[ed]." *Id.* at 2607-09. And EPA could not.

On a first pass, this new 2023 proposal might suggest that EPA has learned its lesson from *West Virginia v. EPA*. CCS and hydrogen co-firing are closer to the sort of traditional systems the agency has looked to as potential BSERs before—ways for individual regulated plants to reduce their own emissions. But a too-quick look can be deceiving. In this case, we worry intentionally so.

Start with CCS. For coal-fired units, EPA is proposing a BSER that requires 90%-capture CCS, beginning in either 2030 or 2035 (depending on operational capacity and whether the plant plans to stay open beyond 2040). 88 Fed. Reg. at 33,244, 33,359. If that type of system were technologically feasible and cost-effective, it would sound much like a technology that could lead to a "standard for emissions of air pollutants" that a particular "existing source" could meet. 42 U.S.C. § 7411(a)(1), (d). Problem is, it's not. As we explain in detail below, *infra* Part III.A., CCS technology is not ready for full-scale commercial use—and not at 90% for a couple hundred coal-fired plants within the next 8 or 13 years.

As we also explain below, the lack of real-world success for CCS anywhere close to the levels EPA wants to impose would doom the Proposed Rule under the rest of the statute. Mandating speculative technology is wishful thinking. It's different from choosing an "adequately demonstrated" system that accounts for "the cost of achieving [emission] reduction[s] and any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1). So a reviewing court can and likely would reject it on those grounds.

Major-questions analysis confirms that result. Finalizing the CCS BSER would force coal plants to shut down. Justice Kagan's dissent in *West Virginia* explained that CCS's "exorbitant costs would almost certainly force the closure of all affected coal-fired power plants." 142 S. Ct. at 2639 (Kagan, J., dissenting). Justice Kagan was wrong that mandating CCS would be legal under the CAA (setting aside the inside or outside the fenceline debate, a BSER must still satisfy the remaining statutory factors). *See Students for Fair Admissions, Inc. v. President & Fellows of Harvard Coll.*, 143 S. Ct. 2141, 2176 (2023) ("A dissenting opinion is generally not the best source of legal advice on how to comply with the majority opinion."). But she was right about the consequences of a CCS BSER: the elimination of coal-fired plants. And EPA knows it, too. The Proposed Rule concedes that it will force almost two dozen power plants to shut down and eliminate thousands of jobs by 2040. *See* EPA, REGULATORY IMPACT ANALYSIS 6-6 (2023), *available at* https://bit.ly/4592mBF. This estimate is wildly under-inclusive—if a standard is impossible to meet, more than 24 plants will have trouble with it. Relevant unions have already identified more than 273,000 direct jobs at risk from the Proposed Rule, with another 1.1 million indirect jobs associated with coal, rail, gas, and utilities further at risk. *See* Int'l Bhd. of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers, et al., Joint Union Comments on Proposed U.S. EPA Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units, at 14-15 (Aug. 4, 2023). But either way, even the EPA's low figure pushes the proposal into major-questions territory. *West Virginia*, 142 S. Ct. at 2593 ("The Government projected that the [CPP] rule would … require the retirement of dozens of coal plants, and eliminate tens of thousands of jobs.").

A 90% CCS mandate would be functionally the same as the CPP's emissions allowance that was too low for coal-fired plants to operate at their existing levels. As the Court explained, a BSER must lead to *achievable* standards—a regulated source should have a choice how to comply with the standard, but the "key" to regulation is that the limit "be no more than the amount achievable through the application of the [BSER]." *West Virginia*, 142 S. Ct. at 2601 (cleaned up). And on this score, the new BSER is worse than straight generation-shifting. After all, a coal-fired plant with an ultra-low emissions cap could still generate *some* power before hitting its limit. But under the Proposed Rule, a coal-fired plant without a 90% CCS system would be unable to generate anything after 2030 or 2035. Through an ostensibly technology-based BSER that leads to unreachable standards, EPA thus aims to impose an even more aggressive form of generation shifting in a different guise. The agency would leave operators no choice but to retire coal plants and replace their lost generation with power from other sources that are not under the same regulatory death sentence.

Hydrogen co-firing as a BSER leads to the same end. EPA would require all intermediate and baseload natural gas combustion turbines to co-fire 30% of a particular "ultra-low greenhouse gas" hydrogen by 2032—and for baseload turbines 96% of it by 2038. 88 Fed. Reg. at 33,244. All the same critiques of CCS apply to this idea, too: The technology to co-fire at 96%, along with the infrastructure to support that massive change, is non-existent. *Infra* Part III.B. Even co-firing at 30% is not an adequately demonstrated technology for existing plants (unlike, potentially, new builds, which the statute treats separately in Section 111(b)). *E.g.* 88 Fed. Reg. at 33,364 (describing two retrofitted combustion turbines that co-fire 5% and 20% regular hydrogen). So once again, finalizing this BSER would mean functional generation shifting. Natural gas plants can't keep the lights on if they must implement impossible technology to do it.

The co-firing BSER also violates *West Virginia* for a simpler reason: Wholesale fuel switching forces natural gas plants to transform into hydrogen plants. Nothing subtle or indirect about it; replacing one source with another is generation shifting, just on a single-plant level instead of grid-wide. Even the *West Virginia* dissent knew how big a deal "requir[ing] a plant to burn a different kind of fuel" could be—a BSER like that could "significantly restructure the Nation's overall mix of electricity generation." 142 U.S. at 2639 (Kagan, J., dissenting) (cleaned up). And the majority threw cold water on the idea that EPA could regulate in this way. Not only has EPA "never ordered anything remotely like that" before (another tell we're dealing with a major question, *id.* at 2608, 2610), but the Court "doubt[ed] it could." *Id.* at 2612 n.3. It's easy to see why: Section 111(d) guides States "in establishing standards of performance for existing sources," not "direct[ing] existing sources to effectively cease to exist." *Id*. (cleaned up).

In other words, existing natural gas plants must be able to comply with a Section 111(d) standard *while remaining natural gas plants*. But the Proposed Rule's fuel-switching mandate would eliminate the entire "natural gas combustion turbine" category of stationary sources by forcing the units within it to turn into something else—hydrogen plants. EPA *might* be able to squeeze past a reviewing court's eye with its initial 30% figure, assuming *Chevron* deference remains available when the agency finalizes this rule. *But see Loper Bright Enters. v. Raimondo*, No. 22-451 (U.S. May 1, 2023) (granting certiorari on *Chevron* deference). But 96% co-firing crosses the line by any measure. After all, numerous natural gas turbines can co-fire 5% hydrogen today, and some do, but no one calls those units "hydrogen turbines." The opposite is true too: Turbines firing only 4% natural gas would be hydrogen plants co-firing natural gas, not the other way around. So we see it again: Though the Proposed Rule speaks in technology-based terms, it is really regulating a category of existing sources out of existence.

For both BSERs, then, the bottom line is the same: EPA is repeating the CPP's mistakes. The consensus around CCS, for instance, is that it's a way to sub out fossil fuels for renewables. *See*, *e.g.*, Darrell Proctor, *CCS Technology Supports Coal-to-Gas Switching and Carbon-Based Products*, POWER (Dec. 1, 2021), https://rb.gy/zkzpq ("The technology is designed to facilitate the transition to natural gas-fired generation at plants making a switch from coal to gas."); Dustin Bleizeffer, *Utilities: Wyo CCUS Mandate Could Spike Monthly Bills by $100*, WYOFILE (Apr. 19, 2022), https://rb.gy/eznja ("It just doesn't make sense [to use CCS] when wind and solar are right there and so much cheaper."). Even EPA acknowledges that CCS is part of a "transition within the power sector" from fossil fuels to renewables—rather than a long-term strategy for coal plants to operate more efficiently. *Questions for Consideration*, EPA (Sept. 22, 2022), https://perma.cc/9GT9-CSXT.

Nor does it matter that the Proposed Rule tries to get to the CPP's ends a different way; the effect is what matters. Much like courts look to the "crux" of a complaint, "setting aside any attempts at artful pleading," *Fry v. Napoleon Cmty. Sch.*, 580 U.S. 154, 169 (2017), courts reviewing the Proposed Rule would look beyond how EPA couches things. Indeed, "courts have long looked to the *contents* of the agency's action, not the agency's self-serving *label*." *Azar v. Allina Health Servs.*, 139 S. Ct. 1804, 1812 (2019) (emphases in original); *see also Arizona v. Biden*, 31 F.4th 469, 482 (6th Cir. 2022) ("The content of the agency's action, not its name, shapes the inquiry."); *Meyers v. Cincinnati Bd. of Educ.*, 983 F.3d 873, 881 (6th Cir. 2020) (noting that the "substance matters more than labels"). And EPA may not do indirectly what Congress withheld power to do directly. *See PPG Indus., Inc. v. Harrison*, 660 F.2d 628, 636 (5th Cir. 1981) (striking down EPA rule that "attempt[ed] to achieve indirectly in this case what it could not do directly under the Clean Air Act: require the use of a certain type of fuel in order to comply with a performance standard").

Whatever EPA calls its new approach, the agency is still trying to "forc[e] a shift throughout the power grid from one type of energy source to another," *West Virginia*, 142 S. Ct. at 2611-12. It's hard to view "[t]he point" of this proposal as anything other than "compel[ling] the transfer of power generating capacity from existing sources to wind and solar." *Id.* at 2604. For instance, deciding "how much of a switch from coal to natural gas is practically feasible by 2020, 2025, and 2030 before the grid collapses," *id.* at 2612, is just like deciding that coal- and natural-gas fired plants need to close or become something else by 2030, 2032, 2035, or 2038. But the Court already rejected the whole way of thinking that Section 111 could be less "about pollution control" and more "an investment opportunity for States, especially investments in renewables and clean energy." *Id.* at 2611-12 (cleaned up). Again, under the statute Congress wrote, EPA doesn't get to decide "it would be best if coal made up a much smaller share of national electricity generation" or otherwise choose how "Americans will get their energy." *Id.* at 2612.

So the Proposed Rule is trying to take on the same "basic and consequential tradeoffs … that Congress would likely have intended for itself." *West Virginia*, 142 S. Ct. at 2613 (citing W. Eskridge, INTERPRETING LAW: A PRIMER ON HOW TO READ STATUTES AND THE CONSTITUTION 288 (2016)). And the results will be just as market-transforming and economy-disrupting as before. A source-selecting BSER still "fundamental[ly] revis[es]" the CAA, "changing it from one sort of scheme of … regulation into an entirely different kind." *West Virginia,* 142 S. Ct. at 2612 (cleaned up). EPA is still making nationwide "policy judgments" about "electricity transmission, distribution, and storage" without expertise in these critical areas. *Id*. And trying to remake the electricity sector—"among the largest in the U.S. economy, with links to every other sector," *id.* at 2622 (Gorsuch, J., concurring)—still has staggering "economic and political significance," *id.* at 2595 (majority op.) (cleaned up). In short, "this" rulemaking—again—"is a major questions case." *Id.* at 2610.

B. Congress Hasn't Supplied EPA's Missing Clear Statement.

Once back in the realm of major questions, EPA must "point to clear congressional authorization to regulate" in the "manner" the Proposed Rule wants. *West Virginia*, 142 S. Ct. at 2614 (cleaned up). But Congress has not revised the statute EPA is administering to give it that power.

The Supreme Court couldn't find a clear statement to bail out the agency last year. Back then, it concluded that the issues the CPP rule took up were "ones that Congress would likely have intended for itself." *West Virginia*, 142 S. Ct. at 2613. And nothing in the CAA supported EPA's claim that Congress overcame that presumption and delegated the matter instead. *Id.* at 2614. "[D]efinitional possibilities" from Section 111(a)(1)'s description of a BSER were not enough. *Id.* (quoting *FCC v. AT&T Inc.*, 562 U.S. 397, 407 (2011)). Nor were other parts of the CAA—where Congress set emissions limits or the standard for them *itself* and gave EPA broader powers than those found in Section 111 to make those limits happen. *West Virginia*, 142 S. Ct. at 2615.

Now, the Proposed Rule tries again to deploy an "ancillary provision[]" of the CAA, *Whitman v. Am. Trucking Assns.*, 531 U.S. 457, 468 (2001), in a novel and transformative way, *West Virginia*, 142 S. Ct. at 2610. But EPA is still working with the same statute. The Court noted last year that Congress had repeatedly "considered and rejected" programs like the CPP despite understanding "the dangers posed by greenhouse gas emissions." *Id.* at 2614. (This factor also helps bolster the threshold conclusion that we are dealing with a major question. *See*, *e.g.*, *Brown & Williamson Tobacco Corp.*, 529 U.S. at 159-60; *Gonzales v. Oregon*, 546 U. S. 243, 267-68 (2006).). Nothing has changed since *West Virginia*. After the decision came down, political leaders noted the need to "pass meaningful legislation to address the climate crisis." Press Release, Senate Democrats, Schumer Statement on MAGA Court's Dangerous Decision in *West Virginia v. EPA* (June 30, 2022), https://rb.gy/sky04; *see also*, *e.g.*, Press Release, White House, Statement by President Joe Biden on Supreme Court Ruling on *West Virginia v. EPA* (June 30, 2022), https://rb.gy/8nz2f ("[W]e will keep pushing for additional Congressional action."). So far at least, Congress hasn't.

Members of Congress have also expressed interest in CCS specifically. *See* Benjamin J. Hulac, *Carbon Capture, A Federal Spending Target, Has Much To Prove*, ROLL CALL (Mar. 6, 2023, 3:44 p.m.), https://rb.gy/jgs9t. But again, that interest has not become law.

Nor does the Inflation Reduction Act supply the missing clear statement. Although EPA relies on the recently passed IRA to justify the Proposed Rule's exorbitant costs (as explained below, *infra* Part III.C., unpersuasively), it does not try to rely on the IRA for new substantive regulatory power. For good reason: Congress did not amend or otherwise expand Section 111. The IRA may encourage industry players to adopt clean energy programs through tax credits, but Congress did not take the step of authorizing EPA to force industry to adopt those programs through Section 111. And any argument that Congress made an indirect change to Section 111's scope would fail, too. For one thing, implicit inferences would not satisfy the agency's burden to identify "clear congressional authorization." *West Virginia*, 142 S. Ct. at 2614. For another, Congress passed the IRA under budget reconciliation. This procedural posture means that the statute could only address appropriations—it could not "stray into non-fiscal 'extraneous' subjects." Charles Tiefer & Kathleen Clark, *Deliberation's Demise: The Rise of One-party Rule in the Senate*, 24 RWULR 45, 59 (2019).

A search for a clear statement this year yields the same result as the Court's conclusion last year: Congress's choice matters on this important issue—the "subject of an earnest and profound debate across the country." *West Virginia*, 142 S. Ct. at 2614 (quoting *Gonzales*, 546 U.S. at 267-68). At least so far, that choice is *not* to delegate. The agency therefore has no authority to finalize a rule that looks anything like this proposal. EPA should stop it now.

II. The Proposed Rule Functionally Cuts The States Out Of The Existing-Source-Regulation Process.

Beyond the major-question problems, the Proposed Rule also shuts States out of the regulatory process in way that contravenes the CAA. As the agency well knows, the Act is "a program based on cooperative federalism." *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 537 (2014) (Scalia, J., dissenting). "Down to its very core, [it] sets forth a federalism-focused regulatory strategy." *Id.*; *accord id.* at 511 n.14 (majority op.); *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1317 (D.C. Cir. 2015); 88 Fed. Reg. at 33,266. As reflected in many provisions through the CAA, Congress intended that States would ultimately play a critical role in the Section 111 cooperative-federalism framework—particularly for existing sources like those here. *See* Senator Kevin Cramer, *Restoring States' Rights & Adhering to Cooperative Federalism in Environmental Policy*, 45 HARV. J.L. & PUB. POL'Y 481, 486-87 (2022) ("cooperative federalism is expressly written into the Clean Air Act as it relates to regulating emissions from existing sources," which means States "are the lead regulators and the federal government acts as a backstop").

The CAA's central role for the States makes good sense for many reasons. A State knows its residents' needs better than the federal government. It understands its unique geographical, socioeconomic, infrastructural, and other challenges better, too. It is closer to and thus more accountable to its constituents than the federal government—and especially insulated agencies like the EPA. A State can also respond to changing conditions on the ground more nimbly and surgically than the federal government can. A State has more experience in day-to-day utility regulation. A State usually has a longtime and close regulatory relationship with most utility owners and operators. And state environmental agencies are every bit as committed, skilled, and trustworthy as their federal counterparts. *See* Alison Koppe, *Regulate, Reuse, Recycle: Repurposing the Clean Air Act to Limit Power Plants' Carbon Emissions*, 41 ECOLOGY L.Q. 349, 368 (2014) ("[Section 111(d)] regulations are a model of cooperative federalism, based on the principle that the states are the best judges of what types of emissions control regimes are most suited to local conditions."). For all these reasons and more, the CAA carefully guards state discretion and control.

In line with Congress's intent to preserve state primacy, the CAA expressly affords the States flexibility in shaping their state implementation plans for existing sources once EPA sets the BSER. EPA chooses the BSER and corresponding standard, but "the States set the actual rules governing existing power plants." *West Virginia*, 142 S. Ct. at 2601. EPA plays a limited role in approving state implementation plans, and it may issue its own plan only in the rare circumstance where a state plan proves insufficient. *Id.* at 2602. And the CAA expressly allows a State "to take into consideration, *among other factors*, the remaining useful life of the existing source" when developing its implementation plan. 42 U.S.C. § 7411(d)(1) (emphasis added). The leeway to consider remaining useful life is broad in and of itself—many of us have explained that elsewhere. *See* State of W. Va., et al., Comment Letter on the Proposed Rulemaking Titled "Adoption of and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)" 7-9 (Feb. 27, 2023), https://bit.ly/47c8bQx.

But the use of the non-exclusive term "among other factors" in Section 111(d) shows that Congress intended States to consider even more than remaining useful life. States might incorporate state-specific concerns pertaining to compliance costs, environmental considerations, energy matters, and other factors that EPA considers at the national level during the BSER stage. Or they might use their discretion to get creative in employing different ways to hit the "target" EPA sets; for instance, they might consider varying modes of operation; whether to apply rate or mass emission limits (or both); whether to incorporate a grid-reliability safety valve; whether to provide for reliability-focused "off ramps" to address extreme weather or similar events; and whether to allow reasonable compliance margins. For years, States have wielded these and other tools in the service of their communities—exactly what Congress envisioned.

The Proposed Rule turns all that upside down. True, the Proposed Rule does not purport to mandate statewide, facility-specific emission limits directly. But as further explained below, *see infra* Part III, and as we've already discussed at some length, *see supra* Part I.A, EPA has used technologically impossible BSERs to set its limit—and that choice achieves the same effect. In reality, "there is no control a plant operator can deploy to attain the emissions limits established by [the Proposed Rule]'s Plan." *West Virginia*, 142 S. Ct. at 2610. Constrained by an unduly restrictive limit produced from the "application" of imaginary technologies, States will thus be compelled to abandon their discretion and take the maximally aggressive approach EPA commands. Energy considerations and the like will necessarily fall by the wayside; facilities will need to close if the States are to implement the suffocating targets EPA proposes—and the States have no room to avoid that outcome through source-specific considerations. *See*, *e.g.*, *The US EPA's Proposed Regulation Could Help To Kill Off Fossil-Fuel Plants. Good On It*, NATURE (June 13, 2023), https://bit.ly/43QOJpI (explaining how the Proposed Rule's onerous standards mean that, "[i]n most cases" coal and other fossil-fuel plants will "shut down").

Remaining useful life itself will become an afterthought, too; no plant can be spared if EPA's numbers are to be hit. And the statute doesn't allow the rejoinder that *EPA* has taken remaining useful life into account in the BSER—like, for example, in the tiered approach to coal-fired plants based on planned retirement dates discussed above. Regulations under Section 111(d) "*shall* permit *the State* in applying a standard of performance to any particular source … to take into consideration … the remaining useful life of the existing source." 42 U.S.C. § 7411(d) (emphases added). The proposal violates this plain command in leaving no suggestion that EPA would consider state plans viable that depart from EPA's strict judgments. In fact, it says the opposite: EPA intends to "ensure that use of [remaining useful life] does not undermine the overall presumptive level of stringency of the BSER." 88 Fed. Reg. at 33,381; *see also id.* at 33,382 (stating that the agency will not let consideration of remaining useful life "undermine the overall presumptive level of stringency and the emission reduction benefits of an emission guideline, or undermine and render meaningless the EPA's BSER determination"). The proposal also reinterprets this factor to the point of making it a nonissue. The Proposed Rule already ignores significant evidence showing that CCS and co-firing are unreasonably expensive as well as technically and physically impossible; these challenges can intensify based on the facility's location, too. *See infra* Part III. But the three factors EPA says it will use to decide whether a State has appropriately employed the remaining-useful-life factor are (1) "[u]nreasonable cost," (2) "physical impossibility or technical infeasibility," and (3) "other circumstances specific to the facility." 88 Fed. Reg. at 33,382. In other words, the Proposed Rule claims to have preemptively analyzed that factor for every State and answered, "Does not apply."

And even if EPA hadn't telegraphed its answer on remaining useful life, we could still be confident that States could not satisfy EPA if they exercise their congressionally promised discretion because the agency's process makes that so difficult. EPA says that remaining useful life applies only when "a State can demonstrate that something unique to the source[] …—something that the EPA did not consider in evaluating the BSER—results in the affected EGU not being able to reasonably achieve the standard of performance." 88 Fed. Reg. at 33,382. "[M]inor, nonfundamental differences" don't count. *Id*. The only costs that could trigger relief are those that "that constitute outliers, *e.g.*, that are greater than the 95th percentile of costs on a fleetwide basis." *Id.* at 33,383. And as far as technical issues, only literal "impossibility" justifies consideration of remaining useful life. *Id.* Taken together, it's no wonder EPA thinks zero coal-fired facilities and basically no natural gas facilities will warrant relief under the factor. *Id.*

The choice to straitjacket the States in these ways will have real consequences. States will be forced to implement the sort of generation-shifting and the like that drew so much (justified) criticism in the ill-fated CPP. It will destroy States' ability to build on existing state energy programs, as no one has come close to mandating CCS or co-firing before. States have also invested broadly in renewable energy, but the Proposed Rule might make it challenging to "get credit" for those gains. So States the country over will have to realign their energy regulation plans, some several decades out. This rearrangement will cause major and long-term inefficiencies.

EPA insists that States retain flexibility because the Proposed Rule allows for things like "trading and averaging in their State plans." 88 Fed. Reg. at 33,392. Combined with the (abridged to the point of nonexistence) remaining-useful-life factor, EPA thinks this ability will provide all the flexibility and tailoring anyone could want. *See*, *e.g.*, *id.* But EPA is wrong in insisting that all is well.

Other parts of the Proposed Rule show that these promises of flexibility are illusory. Most obviously, EPA isn't willing to relax its BSERs enough to provide meaningful relief. For example, EPA says that the Proposed Rule's strictness "will likely require that certain limitations or conditions be placed on the incorporation of averaging and trading in order *to ensure that such standards are at least as stringent as the EPA's BSER*." 88 Fed. Reg. at 33,392 (emphasis added). And as we just explained, EPA doesn't think that States should have any real room to run with the remaining-useful-life discretion Congress gave them, either. In other words, States may have all the flexibility in the world—so long as they don't use it to change anything.

And by admitting that the States will likely need to fall back on trading and averaging to create plans that meet EPA's limits, the agency effectively concedes the States' major-questions-related concern: The Proposed Rule is nothing more than compelled generation shifting by another name. Plant operators will have no choice other than to pour their money into EPA's favored technologies and abandon coal and natural-gas technologies. Yet "Section 111(d) empowers EPA to guide States in establishing standards of performance for existing sources, not to direct existing sources to effectively cease to exist." *West Virginia*, 142 S. Ct. at 2612 n.3 (cleaned up).

Rejecting cooperative federalism and Section 111(d)'s express role for the States is a mistake. Like the rest of the statutory failings, EPA's choice to erase the States makes the Proposed Rule illegal.

III. Both Proposed BSERs Fail The Remaining Statutory Factors.

Even setting major-questions and cooperative-federalism concerns aside, EPA would still be on exceedingly thin ice finalizing its proposal. CCS and ultra-low greenhouse gas hydrogen co-firing—in general, and even worse at EPA's extreme percentages—fail every part of what it means for a system to be "adequately demonstrated."

The CAA tasks EPA with determining the BSER that States use to develop standards of performance for the individual existing sources within their borders. 42 U.S.C. § 7411(a)(1), (d). The "B" matters—EPA must set the "best" system according to specific metrics Congress set. *Id.* § 7411(a)(1). Congress's central requirements are that a BSER must be "adequately demonstrated" to the point that emissions standards "reflect[ing]" the BSER are "achievable"—not policy pipedreams. *Id.* This all means EPA must show that its BSER is "reasonably reliable, reasonably efficient, and … can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973). The analysis is holistic: EPA must consider *all* "significant variables." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 445 (D.C. Cir. 1980).

Congress also made sure EPA could not skip three specific factors along the way: The agency must "tak[e] into account the cost of achieving [the emission] reduction and any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1). Cost consideration mainly includes capital costs, but also considers secondary consequences like "frequent systemic shutdown to service emissions control systems." *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46. "[C]ounter-productive environmental effects" are enough to doom a BSER under the second prong. *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 385 (D.C. Cir. 1973). And energy requirements like a rule's consequences for grid reliability are especially important when, as here, EPA is regulating power plants directly. *West Virginia*, 142 S. Ct. at 2612. Courts usually balance these and other variables "cumulative[ly]"—but the case against a rule on one factor can also be "so cogent" that it clinches the analysis on its own. *Nat'l Lime Ass'n*, 627 F.2d at 431.

All told, "adequately demonstrated," "achievable," and the three enumerated factors mean that EPA must respect the line between cutting-edge and experimental technology. Again and again, courts have reminded EPA that no matter how "laudable" its "objectives" in setting a BSER, Section 111 "expressly requires" that the technology (and the emission limits flowing from it) "be achievable." *Portland Cement*, 486 F.2d at 402. And not just some of the time or under special conditions—achievable "under most adverse conditions which can reasonably be expected to recur." *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46. A BSER that ignores routine variations in conditions fails. *Id.*

Perhaps the most important tools to help decide whether a technology is appropriate for a BSER are sound studies and relevant real-world exemplars. Courts often disregard or discard tests that do not mirror real-time conditions. *See*, *e.g.*, *Essex*, 486 F.2d at 436 ("the relevancy" of certain EPA tests was "at best minimal" because the plants were running at only about half capacity were when tested). In *National Lime Association*, for example, the court remanded a rule, in part, because it appeared EPA's testing and data couldn't answer whether the proposed BSER represented "the industry as a whole." 627 F.2d at 432. EPA had also disregarded the full range of possible operating conditions, including "periods of abnormal operation," as well as all the "relevant variables that may affect emissions in different plants." *Id.* at 430, 433. And showing that a technology works outside of controlled or experimental conditions is critical, too. *Essex*, for instance, excused the fact only one plant using the proposed system existed in the United States because it had "been used extensively in Europe" for a while. 486 F.2d at 435.

That's not to say EPA can never extrapolate or predict where technology will be in the near-future—especially to respond to stakeholder concerns, particularly when it comes to *new* facilities (rather than existing ones). *Portland Cement*, 486 F.2d at 391. So using regulatory power to push current technologies a bit further ahead is not new in the Section 111 analysis. And "[b]y the very nature of its newness, it would be inevitably harder for EPA to acquire as precise and complete information about the emerging technology." *Sierra Club v. Costle*, 657 F.2d 298, 348 (D.C. Cir. 1981). But even so, the "greater the imprint of the new technology" on the BSER, "the more demanding" courts are when reviewing EPA's "evidence about the potential benefits and capabilities of new technology." *Id.* Section 111'd statutory hurdles are thus intentionally built in "difficult[ies] of justifying a standard" that prioritizes "new technology." *Id.* (explaining that to conclude otherwise would allow "circumvention of the primary statutory goals"). These hurdles should be especially high for existing sources, where sunk costs are already high.

We can see this dynamic at work in *Lignite Energy Council v. U.S. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999)—the court concluded EPA had good evidence that its selective catalytic reduction BSER would work on power utility boilers because it was already working well on industry boilers. *Id.* And EPA could answer specific concerns stemming from the different boilers' different loads because the technology was in use in a "wide range of operating conditions," fluctuating loads included. *Id.* So EPA reasonably extrapolated from known, broad, real-world examples to answer this specific objection. *Id.*

In short, *Lignite Energy* shows that EPA can take on the burden to show an emerging technology is a BSER, but that burden is heavier than normal. All the agency's predictions are subject to review, and they must all be "fair[]" projections. *Portland Cement*, 486 F.2d at 391. EPA may not set a BSER "solely on the basis of its subjective understanding of the problem" or a "crystal ball inquiry." *Essex*, 486 F.2d at 433 (cleaned up). Nor may it move ahead "on mere speculation or conjecture," *Lignite*, 198 F.3d at 934, no matter how important the underlying policy objectives. A BSER is never legitimate if it is based on "purely theoretical or experimental" technologies. *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 786 (D.C. Cir. 1976).

Unfortunately, that's what EPA proposes doing here.

A. CCS Cannot Be A BSER.

Carbon capture and storage/sequestration has been around for several decades—but it is still nascent technology and is nowhere near ready for full-scale commercial use.

The Proposed Rule would require all baseload (that is, running at least ~50% capacity) coal- and natural-gas-fired plants to begin operating CCS systems at 90% by 2030 and 2035, respectively. The "capture" part of the process works by rerouting the flue gas (the power plant's exhaust), cooling it, and passing it through a solvent or membrane to isolate the carbon while letting the rest of the flue gas escape. The carbon is extracted from the agent and then cooled and collected, often offsite. The "storage" piece means that the carbon is eventually transported somewhere else for use or long-term storage.

CCS isn't a viable BSER. The energy sector is still very much in the development phase for all aspects of the process: capture, transportation, and sequestration/storage. Even with reasonable predictions about near-future technology, it would likely be impossible to deploy CCS to the degree the Proposed Rule requires. And even if it were possible, it would be exorbitantly costly, would come with serious environmental and health side effects, and would devastate energy production nationwide. So viewed through any of the statutory factors' lenses, CCS is merely speculative—not "adequately demonstrated."

1. CCS does not work in the real world.

CCS is still an emerging technology with almost zero successful examples at all—and *no* commercial-scale examples in America's energy sector. When EPA lists many state actions taken to combat climate change, it's telling that no State mandates CCS. 88 Fed. Reg. at 33,246. This is no surprise. The Department of Energy is using money from the Infrastructure Investment and Jobs Act to fund what it calls "Demonstration Projects." DEP'T OF ENERGY, FINANCIAL ASSISTANCE FUNDING OPPORTUNITY ANNOUNCEMENT CARBON CAPTURE DEMONSTRATION PROJECTS PROGRAM (Sept. 22, 2022), https://bit.ly/3KwiYeR. Similarly, in September 2022 DOE's Office of Clean Energy Demonstrations sent out a Funding Opportunity Announcement that solicited CCS demonstration proposals. *Carbon Capture Demonstration Projects Program*, DEP'T OF ENERGY (May 15, 2023), https://tinyurl.com/27xjxwr8. The Proposed Rule admits that these and other DOE studies were commissioned "to prove feasible scalability at the industrial scale for these new technologies." 88 Fed. Reg. at 33,299. So EPA tacitly admits that CCS technology isn't ready for prime time.

This chart from the National Center for Carbon Capture's R&D team is illustrative. It estimates that the *first* CCS demonstration projects will not ramp up and become operational until late 2030 through 2032:

Southern Company, Comment Letter on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants 9 (Dec. 21, 2022), https://tinyurl.com/59zaya4c. And that's assuming no significant project delays across the decade. *Id.* Even so, the Proposed Rule would require baseload plants to have moved to a 90% CCS model before the first demonstration projects have made it across the finish line.

Some predictions and lack of exact data are fine in the Section 111(d) space. *See Sierra Club*, 657 F.2d at 348 ("By the very nature of [a technology's] newness, it [is] inevitably harder for EPA to acquire as precise and complete information."). But when EPA chooses to traffic in unknowns for a BSER, the level of review "of the evidence about the potential benefits and capabilities of [the BSER]" should be quite "demanding." *Id.* Here, CCS falls prey to all the predictable "difficult[ies] of justifying" a BSER that tries to force "new technology" on the industry. *Id.* So a reviewing court would likely find that letting EPA regulate based on the rosiest of future predictions would "circumvent [Section 111's] primary statutory goals." *Id.*

Indeed, nearly every aspect of the carbon-capture process is still back in the development phase. Start with the technology's components. When it comes to the solvents used to isolate carbon from the rest of flue gas, for membranes and fuel cells in CCS, "no field test" has "confirm[ed] that this technology is viable." *See*, *e.g.*, Southern Company, *supra*, at 26-27. Polymeric membranes and combination solvent/membrane systems show potential, but neither is ready yet even for demonstration. SHIGUANG LI ET AL., PILOT TEST OF A NANOPOROUS, SUPER-HYDROPHOBIC MEMBRANE CONTACTOR PROCESS FOR POST-COMBUSTION CARBON DIOXIDE CAPTURE (2017), https://tinyurl.com/mr2fsb9y. And solid sorbents face similar problems—they haven't yet been demonstrated at relevant scale. SHARON SJOSTROM ET AL., EVALUATION OF SOLID SORBENTS AS A RETROFIT TECHNOLOGY FOR CO2 CAPTURE (2016), https://tinyurl.com/smp46usb.

The same is true for studies and examples of the technology as a whole. Just last year one study noted that "no full-scale [natural gas combined cycle] power plants with [CCS] have been built anywhere in the world; even pilot studies using … flue gas conditions are limited," meaning little data exists "for process simulation model validation under conditions of interest for commercial … plants." W.R. ELLIOTT ET AL., BECHTEL NATIONAL, INC., FRONT-END ENGINEERING DESIGN (FEED) STUDY FOR A CARBON CAPTURE PLANT RETROFIT TO A NATURAL GAS-FIRED GAS TURBINE COMBINED CYCLE POWER PLANT (2X2X1 DUCT-FIRED 758-MWE FACILITY WITH F CLASS TURBINES) 33 (2022) ("Sherman Study"), https://tinyurl.com/7k4psybk.

Let's look at the examples EPA marshals.

Petra Nova is the onetime premier CCS facility in the United States that EPA uses as its main example. 88 Fed. Reg. at 33,293. Begun in 2017, this $1 billion CCS facility located near Houston was designed to capture 90% of the CO_2 emissions—the same target the Proposed Rule would require—from a 240-MW slip stream on a 610-MW coal-fired plant. Nichola Groom, *Problems Plagued U.S. CO2 Capture Project Before Shutdown*, REUTERS (Aug. 6, 2020, 7:45 p.m.), https://tinyurl.com/4autujp3. But in the three short years it ran, the CCS system caused plant outages around 100 days, and the plant missed its overall CO_2 reduction target by 17%. *Id.*

Petra Nova wasn't even a large project—at least not by EPA standards. *See* 88 Fed. Reg. at 33,317 (defining a plant with "a maximum of several hundred MW" as "a smaller EGU," while Petra Nova's slipstream was just 240-MW); *see also* Sam Korellis, POWER, *Utilities and Industry*

Continue Learnings Around Benefits of Heat Rate Improvement (Jan. 3, 2022), https://tinyurl.com/5s2jbcy2 (Jan. 3, 2022) (defining a "typical" coal plant as 500-MW). It also received significant federal assistance and sold its captured carbon to a facility just 80 miles away. Groom, *supra*. Even so, Petra Nova's CCS system was never economically viable—so it was mothballed in 2020 and sold a couple of years later to a Japanese company. Carlos Anchondo & Jason Plautz, *Company Sells Stake in Shuttered Petra Nova CCS Project*, E&E NEWS: ENERGYWIRE (Sept. 22, 2022, 7:15 a.m.), https://tinyurl.com/yc6x3cjk. As the Institute for Energy Economics and Financial Analysis noted in 2020, Petra Nova's closure "highlights the deep financial risks facing other proposed U.S. coal-fired carbon capture projects." DENNIS WAMSTED & DAVID SCHLISSE, PETRA NOVA MOTHBALLING POST-MORTEM: CLOSURE OF TEXAS CARBON CAPTURE PLANT IS A WARNING SIGN (2020), https://bit.ly/3s6Kp8r.

Despite this failure, EPA considers this example enough to justify CCS for coal-fired plants writ large because of lessons industry "learned" from a plant closed because of "poor economics." 88 Fed. Reg. at 33,293. But EPA never explains what is different now because of Petra Nova's example; it simply "anticipate[s]" that future facilities will get better. *Id.* at 33,291. And the only other example the proposal gives of a coal-fired plant that used CCS is a *25-MW* slip stream CCS system. *Id.* With Petra Nova already smaller than the "smaller" plants the Proposed Rule would reach, it stretches credulity that this single example one-seventh even *that* size could show that full-scale commercial deployment is "adequately demonstrated."

The lignite-fired Boundary Dam facility in Saskatchewan doesn't move the ball much, either. Its 90%-capture CCS system cost $1.5 billion and was installed in 2014 on a 110 MW unit. *See* 88 Fed. Reg. at 33,291; *Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project*, MIT, https://tinyurl.com/bmfm5cxt (last accessed Aug. 1, 2023) ("The original cost was $1.3 billion. Of that original cost estimate: $800 million was for the CCS process, with the remaining $500 million for retrofit costs."). For years it suffered from many "serious design issues," causing it to operate at 40%. Geoff Leo, *SaskPower looking for help to fix 'high cost' Boundary Dam carbon capture flaw*, CBC NEWS (May 28, 2018, 6:07 p.m.), https://tinyurl.com/mvzpjuys. This meant that in its first four years, it captured only four million metric tons of carbon dioxide equivalent. *Id*. And it paid millions in fines when it failed to hit certain benchmarks. *No more retrofits for carbon capture and storage at Boundary Dam*, CANADIAN PRESS (July 9, 2018), https://tinyurl.com/fyb28hhy. Nor were its problems limited to the first few years. In 2018, it had to call in emergency engineering help because the Shell-brand amine solution it was using—CANSOLV, which EPA plans for regulated sources to use here, 88 Fed. Reg. at 33,291—degraded twice as fast as anyone predicted. *Id.* Because of all these troubles, the Boundary Dam CCS system met its goal and captured 90% of CO_2 for the first time *eight years after installation* in the last two quarters of 2022. 88 Fed. Reg. at 33,291-92. It's probably no surprise, given all that, to see that Boundary Dam's owner refuses to add CCS systems to its other units. 83 Fed. Reg. 65,424, 65,436 n.61 (Dec. 20, 2018) (noting this refusal was, among other things, "due to high costs").

To find a natural-gas CCS example, EPA must go back more than 20 years to the Bellingham Energy Center in south central Massachusetts, which stopped operating in 2005. 88 Fed. Reg. at 33,292. And (again), that CCS system was tiny, installed on a 40-MW slip stream.

Id. The only other natural gas CCS facilities the Proposed Rule can find are in the planning stages. *Id.* EPA points to a proprietary NET Power Cycle it expects to work well, but the one system using that technology now took many years to go through just testing and grid connection, and it was only a 50-MW facility. *Id.* The Proposed Rule hesitates to use just one plant's numbers in setting the phase one BSER for intermediate load sources. *Id.* at 33,324 (not setting the rate at 1,100 lb CO_2/MWh-gross because it "is aware of a single" example of the relevant technology). EPA should exercise the same caution here.

The Proposed Rule goes against the words of caution from myriad government entities and industry players—an unsurprising outcome considering the missing real-world support for CCS at scale. Consider this sampling:

- The Congressional Research Service recognized late last year that "[t]here is broad agreement that costs for constructing and operating CCS would need to decrease before the technologies could be widely deployed." CONG. RESCH. SERV., *Carbon Capture and Sequestration (CCS) in the United States* (updated Oct. 2022) at 1, https://tinyurl.com/rmf65bry.

- The Government Accountability Office said around the same time that although capture technologies might be considered mature in some sectors, they "require further demonstration in some of the highest-emitting sectors," including "power generation." U.S. GOV'T ACCOUNTABILITY OFF., GAO-22-105274, DECARBONIZATION 3 (2022), https://tinyurl.com/xmm7vk9j; *id.* at 19 ("[t]he most mature technology (solvent-based system using amine) has only been deployed in a subset of possible configurations of coalfired power generation facilities").

- The United Nations issued a 2018 Special Report from its Intergovernmental Panel on Climate Change's 2018 Special Report that said only some modeling "suggests" CCS might be effective long term. And despite significant efforts, CCS costs refuse to "come down" (making it uneconomical), potential storage capacity remains uncertain, and whether CCS will work varies widely by region. HELEEN DE CONINCK ET AL., INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, 2018 SPECIAL REPORT 326-27 (2018), https://tinyurl.com/827skmwz.

- The Southern Company emphasizes that CCS technology is not ready, stating that it still "has not been deployed to date at commercial-scale as an environmental control technology, where reliability and consistent performance are paramount requirements." Southern Company, *supra*, at 7. It objected to EPA's waffling on which CCS technologies are "in the research, development, or demonstration stages and are not commercially available," *id.*, for not "fully describ[ing] the limitations and challenges that have been identified and encountered by the reported approaches," *id.* at 20, and for focusing on "projects that are in the planning stages," *id.* at 25. CCS still "needs to be demonstrated at a scale" well "above" where it is now "to identify and address operational issues before being considered commercially available." *Id.* at 26.

- The Institute for Energy Economics and Financial Analysis studied 13 flagship CCS facilities across seven economic sectors and found that 10 of the 13 either "failed or underperform[ed] mostly by large margins." IEEFA, *The Carbon Capture Crux* 71 (Sept. 2022), https://tinyurl.com/nhjupmbj. So history shows that using CCS technology "is a significant financial and technical risk." *Id.* at 74. And CCS's long-time "track record of technical failures" has meant that over time "90% of proposed CCS capacity in the power sector has failed at the implementation stage or was suspended early." *Id.*

- The International Institute for Sustainable Development, in summarizing 2023 Intergovernmental Panel on Climate Change work, said that "relying too much on carbon capture technology represents a major *risk* to climate safety"—it "costs too much" and in their view will not do enough anyway. IISD, *IPCC Research Shows Need for Ramping Up Mitigation Ambition, Tackling Adaptation Gaps* (Mar. 22, 2023), https://tinyurl.com/2mxz974b.

This consensus matters because it tells us that the Proposed Rule's claims that CCS can be reliable, efficient, and have low economic and environmental costs are not objectively "reasonable"—the touchstone of the adequately demonstrated analysis. *Essex*, 468 F.2d at 433. Yet despite all this, the Proposed Rule repeatedly acts like CCS is just run-of-the-mill, normal power-plant operations. *See* 88 Fed. Reg. at 33,290-98. Nothing could be further from the truth. Given the utter lack of supporting data, the industry doesn't trust or use CCS. Nicholas Kusnetz, *In a Bid to Save Its Coal Industry, Wyoming Has Become a Test Case for Carbon Capture, but Utilities are Balking at the Pricetag* (May 29, 2022), https://tinyurl.com/2ru86f5b ("Yet so far, the technology has failed to catch on commercially there or elsewhere. And many economists and policy experts say it is unlikely to play a significant role in helping eliminate emissions from the power sector."). The Proposed Rule does not give enough counterevidence to require industry to overcome these well-founded doubts—because it doesn't exist.

Instead, the agency is trafficking in the type of "mere speculation and conjecture" that Section 111 forbids. *Lignite*, 198 F.3d at 934. Setting "achievable" standards, 42 U.S.C. § 7411(a)(1), depends on "achievable" technologies. *Portland Cement*, 486 F.2d at 402 ("[Section 111] expressly requires, for the standards [the EPA] promulgates, that *technology* be achievable." (emphasis added)). And that means accounting for the "most adverse conditions which can reasonably be expected to recur." *Nat'l Lime Ass'n*, 627 F.2d at 433 n.46. But all this non-evidence shows that CCS as a BSER will not lead to "achievable" emission reductions in any case—let alone under adverse conditions. After all, Petra Nova and Boundary Dam had extensive subsidies and other advantages that most existing facilities do not. In other words, they had some of the least adverse conditions imaginable. Yet CCS still failed.

When it comes down to it, even the Proposed Rule is inconsistent in its optimism. For the first third, EPA acts like commercial-scale CCS is ready now and can be deployed by essentially any power plant. *See*, *e.g.*, 88 Fed. Reg. at 33,291 (reviewing "[v]arious technologies" and saying that industry has been "identifying and correcting [various] problems"), 33,292 ("other projects have successfully demonstrated the capture component of CCS"), 33,294 (assuming CO_2 transportation is safe because the regulatory authority has issued an "updated nationwide advisory bulletin"), 33,295 (saying geologic sequestration is adequately demonstrated based on "[e]xisting project and regulatory experience"). But then later in the rule, EPA admits that factors like needing to "deploy[] … CCS infrastructure" to handle carbon transportation and storage are why, for natural-gas combustion turbines, it chose 2035 instead of the 2030 compliance deadline it preferred. 88 Fed. Reg. at 33,304. Unfortunately, the Proposed Rule does not explain why five more years is enough to show that this currently non-existent infrastructure can get up-and-running. And it also never explains why coal-fired plants can hit the 2030 mark; perhaps EPA is indifferent towards an early compliance date when it comes to coal because that the Proposed Rule will shutter those plants before then.

This lack of evidence is ultimately fatal. The Proposed Rule points to essentially nothing that currently exists, so it cannot say in good faith that commercial-scale CCS will be "reasonably reliable" in under ten years. *Essex*, 486 F.2d at 433. The Proposed Rule is engaging in a classic crystal ball inquiry. *Id. at 434*.

And EPA knows it. Just a few years ago EPA recognized that CCS "should not be a part of the BSER for existing fossil-fuel-fired EGUs because it was significantly more expensive than alternative options for reducing emissions." 82 Fed. Reg. 61,507 61,517 (Dec. 28, 2017); *see also* 84 Fed. Reg. 32,520, 32,543 (July 8, 2019) (similar). Even the CPP said the same thing: High costs, energy impacts, geographical limitations, and other problems foreclose it as a legitimate BSER. *See* 80 Fed. Reg. 64,661, 64,728 (Oct 23, 2015). Claims that CCS costs have fallen in the past couple years, 88 Fed. Reg. at 33,245, cannot overcome the bevy of studies and resources—including those from the same period—that have confirmed EPA's prior estimates. In short, the agency knew that CCS was not a viable option as early as 2015. The only meaningful change since then is that the Supreme Court has now shut down the option EPA chose instead. But lack of other options EPA likes is not enough to make CCS adequately demonstrated.

2. Each phase of the CCS process fails Section 111(d)'s factors.

Every aspect of CCS—from the initial build to long-term carbon storage—poses severe problems for power plants. It is prohibitively expensive, hurts the environment and health, and damages energy production and reliability. So beyond CCS as a BSER failing the "adequately demonstrated" prong more generally, a reviewing court would very likely also conclude that the agency did not appropriately "consider" each of Section 111(a)(1)'s required factors.

a. <u>Building a CCS system is incredibly costly</u>.

EPA is required to "consider" "cost." 42 U.S.C. § 7411(a)(1). And a proposed system of emission reduction is not adequately demonstrated if it is "exorbitantly costly in an economic" way. *Essex*, 486 F.2d at 433. CCS is exactly that.

Let's assume to begin that a power company can find a workable CCS system that fits their specific plant. This is a dubious assumption itself: First, because of operational limitations and other variables, finding a system that works with an existing source's footprint can be challenging. The operator may not have room to install the machine since CCS systems are usually as big as the source itself—a particular challenge in more urban settings. Southern Company, *supra*, at 9 ("[C]arbon capture equipment requires roughly the same footprint as the existing combined cycle facility. Many facilities do not have sufficient space in proximity to the unit to accommodate the additional equipment and onsite space needs."). And second, natural gas units in particular face significant "technical challenges associated with retrofitting existing units with CCS technology." Edison Electric Institute, *Considerations for Clean Air Act Section 111 Regulation of Existing Natural Gas Units*, p. 3 n.4, https://tinyurl.com/2f4uw634 (last accessed Aug. 4, 2023). But those problems aside, for a plant that finds a good CCS option, the capital costs for purchasing and installing it are sky high. Last year, South Dakota and Wyoming facilities conducted a detailed study that showed that installing a 90%-capture CCS system in *just two* of their coal plants would cost about $1 billion. CHEYENNE LIGHT, FUEL AND POWER CO. & BLACK HILLS POWER, INC., APPLICATION TO ESTABLISH INTERMEDIATE LOW-CARBON ENERGY PORTFOLIO STANDARDS AND REQUIREMENTS 14 (2022) ("Wyoming Study"), *available at* https://tinyurl.com/yw98b3fz. Building the plants from scratch had cost only $300 million. *Id.* at 15.

Similarly, Bechtel National, Inc., conducted a comprehensive front-end engineering design study last year for locating an 85%-capture CCS system at a natural gas combined cycle power plant in Sherman, Texas. It estimated "[t]he overall capital cost … at $477 [million], including indirect costs, owner's and contractor's costs, and interest during construction." Sherman Study, *supra*, at 1. That price tag works out to \$114.50/tCO_2—and even so it is based on likely "overly optimistic" estimates. *Id.* at 30; *see also id.* at Att. 1, Tbl. 1-6 (outlining various costs). Other front-end engineering design studies yield similar results. *See*, *e.g.*, Elec. Power Rsch. Inst., *Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant* 6 (Feb. 2022), https://tinyurl.com/bdhhwhz9 (estimating capital cost for the 90%-capture CCS system "to be $748 [million], with accuracy range of plus or minus fifteen percent").

Of course, these intense capital costs will be passed along to consumers. The Wyoming Study, for example, showed that capital expenses at that level would permanently increase costs by $100 a month per residential ratepayer. Bleizeffer, *supra*. That increase would double Wyomingites' monthly electric bill, which in 2021 was around $97. ENERGY INFO. ADMIN., 2021 AVERAGE MONTHLY BILL - RESIDENTIAL (Oct. 6, 2022), https://tinyurl.com/2wb35t59; *see also Wyoming 2nd Highest In Country For Energy Bills,* COWBOY STATE DAILY (July 7, 2021), https://bit.ly/45frDKn (citing an informal survey that put the number at $115/month).

Even the Proposed Rule admits that using CCS increases capital costs by 115% and incremental operating costs by 35%, leading to a levelized cost of energy increase of nearly $90/metric ton. 88 Fed. Reg. at 33,298. An 115% increase is well above reasonable levels for an agency required to consider cost: Just consider that in *Portland Cement* the overall cost increase was just 12% with annual operating costs increasing 7%. 486 F.2d at 387. And in *Lignite*, the court held that the BSER was appropriate, in part, because it would "only modestly increase the cost of producing electricity." 198 F.3d at 933. This proposal would far exceed those levels by EPA's own admission. Worse, the agency's estimates are likely low. *See* GLOB. CCS INST., TECHNOLOGY READINESS AND COSTS OF CCS 43 (2021), https://bit.ly/3Yqlh96 (cited at 88 Fed.

Reg. at 33,254 n.63, saying that CCS costs for a natural gas combined cycle unit that is not right next to storage "may cost over \$120/t CO_2").

EPA tries to brush this concern away by noting that "the DOE is funding multiple projects" that are exploring how to reduce costs. 88 Fed. Reg. at 33,299. Yet again, EPA isn't sure what these studies will show—the most it can say is that some of them "*could* have reductions in capital, operating, and auxiliary power requirements and *could* reduce the cost of capture." *Id.* (emphasis added); *see also id.* (saying EPA "expect[s]" that some amine-solvent substitutions will "potentially" reduce costs by lowering auxiliary power requirements). In other words, EPA sees astronomical costs and points to studies that might—or might not—give some relief. We have no idea how much relief might result if they pan out or whether it will affect all regulated sources in each category the same rather than turning on site-specific factors at these projects. All this means that the best the agency can say is that these studies might turn into support that CCS is adequately demonstrated at some unidentified future time.

Further, plenty of historical reasons support doubting these "might's." As EPA admits, similar studies conducted 10 years ago predicted that Boundary Dam's costs would be around \$95/metric ton, but its actual costs are \$105/metric ton. 88 Fed. Reg. at 33,299. That EPA tacitly admits its current (and already very high) cost predictions—could be wrong by up to 10% isn't encouraging. Most troublingly though (and as detailed further below), EPA's cost estimates rely on questionably optimistic assumptions—for example, that input costs will remain static over time, or that everyone capturing carbon will be able to offset their costs by selling CO_2 or getting a 45Q tax credit. 88 Fed. Reg. at 33,300 & n.355.

All this (again) went into EPA's former conclusion that CCS could not be considered a BSER. EPA found three years ago that CCS was only *potentially* cost-effective when an affected source is *both* "in reasonable proximity to an existing CO2 pipeline—or to an EOR opportunity"—*and* received significant federal and other subsidies. EPA, RESPONSES TO PUBLIC COMMENTS ON THE EPA'S PROPOSED EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING ELECTRIC UTILITY GENERATING UNITS (EPA-HQ-OAR-2017-0355-26741), ch. 4 at 3-6 (2019), https://tinyurl.com/bdc3tw35. "[A]bsent those very specific circumstances, the EPA has concluded that CCS is not cost-reasonable, nor is it available across the existing coal fleet and cannot be considered to be the BSER." *Id.*

EPA was right then to reject CCS as a BSER—recall that emission reduction standards must be achievable "under most adverse conditions which can reasonably be expected to recur," *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46, not potentially doable in special circumstances only. It unreasonably ignores that finding now, pushing past that earlier analysis despite no real-world change or new data to justify its about face.

b. <u>The post-build capture phase is plagued by operational challenges and unjustified costs</u>.

Even if a source owner or operator manages to pay for a newly required CCS system, its problems would just be starting. *See* 88 Fed. Reg. at 33,299 (listing 14 factors associated with post-capture tasks). Take efficiency to start. CCS units run on power, too. An owner can get that power from the plant itself. But this approach makes the plant less efficient by increasing its "parasitic load"—and CCS more than triples combustion turbines' normal parasitic load. *Id.* at 33,319. This is the cause the Wyoming study analyzed that showed installing CCS technology would devastate plants' heat rates and lower net plant efficiency by 36%. Wyoming Study, *supra*, at 10-11; *see also* Sherman Study, *supra*, at 1-1 (showing parasitic load loss of nearly 10%). "[H]eat rate is the amount of energy used by an electrical generator/power plant to generate one kilowatthour (kWh) of electricity." *What is the efficiency of different types of power plants?*, ENERGY INFO. ADMIN., https://tinyurl.com/553shcpz (Sept. 20, 2022). So with heat rates, the higher the number, the more inefficient the plant.

EPA admits that, judging from one plant it reviewed, CCS increases the heat rate by 13% and parasitic load by 11%. 88 Fed. Reg. at 33,298 & n.339. Even that (perhaps optimistic) figure should stop this proposal in its tracks. Between 2011 and 2021, coal industry's collective heat rate increased by about 1.3%—and natural gas's fell by about 5.7%. ENERGY INFO. ADMIN., TABLE 8.1. AVERAGE OPERATING HEAT RATE FOR SELECTED ENERGY SOURCES, https://tinyurl.com/y6zfdymr (last accessed July 13, 2023). But based on EPA's own numbers, mandating CCS would create *ten times* the heat rate increase the coal industry suffered across the last decade. And it would set the natural gas industry back a decade, erasing its gains by a factor of two.

Heat rate inefficiencies matter because they decrease plants' overall environmental efficiency—they increase the energy consumed (and carbon emitted) per unit of power that is available to consumers. They also matter because they increase costs. Power plants must buy extra fuel to make up for increased inefficiencies and manage the extra emissions from the extra burn. One Electric Power Research Institute study found, for instance, that for a "typical" coal plant (a 500-MW EGU running at 40% capacity and firing bituminous coal), a mere "1% heat rate reduction will save about $360,000 in annual fuel costs." Korellis, *supra*. And we usually see a "one-for-one" correlation between heat rate increases and emissions—so a 1% rate improvement leads to 1% fewer NOx and CO_2 emissions. *Id.* Yet the Proposed Rule wants to go in the opposite direction, and to a degree over 10 times those 1% numbers. With just these financial and environmental costs in view, it becomes even harder for the Proposed Rule to justify CCS's steep price tag.

Alternatively, an owner can run a new CCS unit from a different power source. The Petra Nova plant, for example, installed a new, separate 75-MWh unit just to power its CCS system. This approach doesn't solve the increased costs and increased emissions problems, though: In Petra Nova CCS's first month, emissions from the 75-MWh unit erased about half of its total CO_2 reduction in a straight year-over-year comparison. *Petra Nova is One of Two Carbon Capture and Sequestration Power Plants in the World*, ENERGY INFO. ADMIN. (Oct. 31, 2017), https://bit.ly/3qc6rq1.

Beyond these operational issues, the few examples we have of CCS systems also show that equipment failures are common. In just three years of operation, Petra Nova's CCS system caused stoppages on about 100 days. *See* Nichola Groom, *Problems Plagued U.S. CO2 Capture Project Before Shutdown*, REUTERS (Aug. 6, 2020, 7:45 p.m.), https://tinyurl.com/4autujp3 (reporting that "[s]ince Petra Nova started up in 2017, it suffered outages on 367 days," and "[i]ssues with the carbon-capture facility accounted for more than a quarter of the outage days"). And as EPA notes, Boundary Dam's CCS system had a similarly poor record. What the Proposed Rule tactfully frames as "some additional challenges with availability during its initial years," 88 Fed. Reg. at 33,291, was really operating at a mere 40%—for years—because of unfixable and "serious design issues." Geoff Leo, *SNC-Lavalin-built carbon capture facility has 'serious design issues'*, CBC NEWS (Oct. 27, 2015, 7:32 p.m.), https://tinyurl.com/ynrbbt64.

Indeed, fuel-specific, unit-specific, and site-specific operational challenges are constant for CCS. *See generally* Edison Electric Institute, *supra* (focusing on unit and fuel in particular). If an owner is using a natural gas combined-cycle unit, for example, the CCS system's regenerator preheating will "lengthen startup times and limit the ability to operate at low loads." OFF. OF AIR QUALITY PLANNING & STANDARDS, EPA, AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM COMBUSTION TURBINE ELECTRIC GENERATING UNITS 40 (2022), https://bit.ly/3Kx7UOB (citing Rosa Domenichini, et al., *Operating Flexibility of Power Plants with Carbon Capture and Storage*, 37 ENERGY PROCEDIA 2729, 2731-32 (2013)). What's worse, CCS systems on these natural gas combined-cycle units must treat far more flue gas compared to coal plants, including lots of trace oxygen that the unit produces. E.J. CICHANOWICZ, AM. PUB. POWER ASS'N, 2021 STATUS OF CARBON CAPTURE UTILIZATION AND SEQUESTRATION FOR APPLICATION TO NATURAL GAS-FIRED COMBINED CYCLE AND COAL-FIRED POWER GENERATION 6 (Jan. 2022), https://bit.ly/3OKG2Jc; *see also* 88 Fed. Reg. at 33,299 (admitting that capture costs are most closely tied to the "concentration of CO_2 in the gas stream."). That's why an industrial-sized combustion turbine that operates with CCS equipment doesn't already exist. *Id.* And as for site-specific issues, a unit located somewhere with water constraints would face inordinate difficulties because a CCS unit's cooling process consumes just as much water as the plant itself—meaning water consumption ultimately doubles. EPA has treated water use as a critical factor in setting the BSER before, 88 Fed. Reg. at 33,271 (noting water-based subcategorizations in the past), yet here EPA doesn't even address the issue.

All these operational problems mean that CCS technology is neither "reasonably reliable" nor "efficient." *Essex*, 486 F.2d at 433. And the costs EPA must consider are not limited to initial build and capital expenditures: "[C]ertain 'costs'" also include second-level expenditures—such as "frequent systemic shutdown[s]" or other technology problems. *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46. Adding the second-level costs to the already exorbitantly costly initial outlays provides yet more evidence the Proposed Rule cannot rebut that CCS is not adequately demonstrated.

Piling on the statutory troubles, CCS may also have health consequences. 42 U.S.C. § 7411(a)(1). The Proposed Rule would force utilities to adopt and communities to accept all aspects of CCS technology without fully understanding the ramifications. For example, the environmental and health effects of CANSOLV—the leading amine-based and EPA-recommended CCS solvent, 88 Fed. Reg. at 33,291—appear unknown; leading CANSOLV studies over the past decade don't discuss its impact. *See*, *e.g.*, Karl Stephenne, et al., *Recent Improvements and Cost Reduction in the CANSOLV CO_2 Capture Process* (Oct. 2022), *available at* https://tinyurl.com/yhnz8vsw (focusing strictly on CANSOLV's economics); Ajay Singh & Karl Stephenne, *Shell Cansolv CO_2 capture technology: Achievement from First Commercial*

Plant, 63 ENERGY PROCEDIA 1678 (2014) (focusing only on potential applications). And because CANSOLV is proprietary, it's doubtful that we will see rigorous and independent studies about it anytime soon. Gregory K. Wanner, et al., *Chemical Disaster Preparedness for Hospitals and Emergency Departments*, 5 DEL. J. PUB. HEALTH 68 (2019) (noting that as a rule manufacturers are "hesitant to reveal the specific chemical identity of a proprietary or 'trade secret' product"); OFF. OF CHEM. SAFETY AND POLLUTION PREVENTION, EPA, RISK EVALUATION FOR PERCHLOROETHYLENE 127 (2020), https://tinyurl.com/43k24sve (saying that proprietary information's inherent secrecy can create "uncertainties in the reported data that are difficult to quantify with regard to impacts on exposure estimates" and effects). Other nascent capture technologies—like polymeric membranes, combination solvent/membranes, and solid sorbents—are just as unknown. *See* SHIGUANG LI ET AL., *supra*; SHARON SJOSTROM ET AL., EVALUATION OF SOLID SORBENTS AS A RETROFIT TECHNOLOGY FOR CO2 CAPTURE (2016), https://tinyurl.com/smp46usb.

We do know that using these technologies will have negative environmental side effects (beyond those from increased emissions from the CCS unit's power source). Nearly a decade ago, the European Union's European Environmental Agency released a study finding that CCS would increase "direct emissions of NOx and PM" by nearly a half and a third, respectively, because of additional fuel burned, and increase "direct NH_3 emissions" "significantly" because of "the assumed degradation of the amine-based solvent." EUR. ENV'T AGENCY, AIR POLLUTION IMPACTS FROM CARBON CAPTURE AND STORAGE 7 (2011), https://tinyurl.com/4b68mx99. An NIH study found that these non-greenhouse gas pollution increases would cause a secondary and "troublesome" rise in $PM_{2.5}$. Jinhyok Heo et al., *Implications of ammonia emissions from post-combustion carbon capture for airborne particulate matter*, 49 ENV'T SCI. TECHN. 5142 (2015). And worse, "[t]he public health costs of CCS NH_3 emissions" were "$31-68 per tonne CO_2 captured, *comparable to the social cost of carbon itself*." *Id.* (citation omitted). In other words, this BSER cannot "reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex*, 486 F.2d at 433.

c. Transporting captured carbon is no better.

Once the carbon is captured, we need to add transportation problems onto everything that's come before. Site location is key to CCS viability because we can only do two things with captured carbon: Use it in industry or store it. (Industry use is effectively limited to "enhanced oil recovery," or EOR, a process that pumps captured CO_2 into porous rock formations to drive out the oil trapped in the rock pores.) Either way, CCS systems typically need to be geographically near where EOR or storage opportunities are found, such as sedimentary basins, oil and natural gas fields or reservoirs, or saline formations. *Which Area is the Best for Geologic Carbon Sequestration?*, U.S. GEOLOGICAL SURV., https://bit.ly/3QuDtMQ (last accessed Aug. 5, 2023) (stating that the best storage potential is in the "coastal basins from Texas to Georgia," or Alaska and the Rocky Mountains).

So while plants in Texas and Colorado may be able to bear these costs (though not the many other costs CCS imposes as well), plants in States like West Virginia, Ohio, and Pennsylvania will see their transportation costs skyrocket as they scramble to dispose of captured carbon. The most likely option to try to comply with the Proposed Rule would be an expanded pipeline network. Petra Nova and Boundary Dam were close to EOR projects, for example—about 80 and 40 miles, respectively—and transported carbon there by pipeline. Yet while EPA has tacitly admitted before that site location is important in setting a BSER, *see* 88 Fed. Reg. at 33, 271 (noting it had categorized sources based, in part, on geographic location), here the agency all but ignores geographic location and access to CO_2 storage or use options when proclaiming that CCS is adequately demonstrated across source categories.

Let's pause for a moment at the idea that this BSER requires a new pipeline network to operate. Building pipelines usually costs a couple to several million dollars per pipeline mile. CARBON DIOXIDE PIPELINES: SAFETY ISSUES, *supra* (citing ERIC LARSON ET AL., *supra*). And pipeline construction takes more than just capital costs; regulatory and litigation costs grow the bottom line, too. Apart from significant federal regulations and permitting processes across multiple agencies, state law controls water-quality permitting and many aspects of acquiring rights-of-way. *E.g.*, 88 Fed. Reg. at 33,294 ("States are also directly involved in siting proposed CO_2 pipeline projects. CO_2 pipeline siting authorities, landowner rights, and eminent domain laws reside with the States and vary from State to State."). California, for example, recently paused transportation of CO_2 through its pipelines until the federal government updates its safety guidelines (more on that below). CAL. AIR RES. BD., FINAL 2022 SCOPING PLAN FOR ACHIEVING CARBON NEUTRALITY (2022), https://tinyurl.com/yx8388ed. EPA ignores not only the costs to build lines once all legal boxes are checked, but that unforeseen changes to state law could affect whether construction is even possible.

EPA shrugs off these transportation issues because we currently have over 5,000 miles of pipeline that can move CO_2. 88 Fed. Reg. at 33,294. For at least four reasons, it shouldn't.

First, EPA never analyzes whether that pipeline is helpfully placed—is it near current power plants? Remember, the Proposed Rule is an *existing* source rule, not best practices for new builds. And remember as well that, currently, CCS is used commercially only in non-power sector applications—so the existing pipe network isn't running to power plants. In short, the Proposed Rule gives no sense how many of those 5,000 miles of pipeline will be helpful. And it effectively admits elsewhere in the proposal that current pipeline infrastructure could *not* service "widespread" CCS. *See* 88 Fed. Reg. at 33,283 (saying that "*building* the infrastructure required to support widespread use of CCS … in the power sector will take" a long time (emphasis added)).

Second, pointing to a few private groups' press releases stating that they plan to add several thousand miles of pipeline starting in the next few years, 88 Fed. Reg. at 33,294, does not solve the transportation headache. This hope and a prayer is a wholly unsatisfying response—not just because EPA would build a rule of this scale on top of press release optimism, but because the hoped-for numbers are so paltry. "One recent [Princeton] study suggests that [a nationwide CO_2 pipeline] network could total some 66,000 miles of pipeline by 2050, requiring some $170 billion in new capital investment"—or around $2.5 million per pipeline mile. CARBON DIOXIDE PIPELINES: SAFETY ISSUES, *supra* (citing ERIC LARSON ET AL., *supra*). Several thousand miles of privately installed pipeline wouldn't bridge the gap between 5,000 and 66,000. And given that for the decade between 2011 and 2021 we added a mere 13% of our total pipeline footprint, 88 Fed.

Reg. at 33,294, it's doubtful even the minimal hoped-for expansion the Proposed Rule cites will happen anytime soon. So neither the Proposed Rule's seven-year compliance horizon nor its cost-benefit analysis sufficiently considered what a heavy—really, impossible—task readying these pipelines would be.

Third, while EPA has "solicited research proposals to strengthen CO_2 pipeline safety," 88 Fed. Reg. at 33,294, building so much so quickly poses potentially grave risks to public health. The catastrophic CO_2 pipeline failure in Satartia, Mississippi in 2020—mass evacuations of hundreds of people and 45 hospitalizations from carbon-dioxide poisoning—should be a sobering reminder before finalizing anything like this proposal. *See* Julia Simon, *The U.S. is expanding CO_2 pipelines. One poisoned town wants you to know its story*, NPR (May 21, 2023, 6:01 a.m.), https://tinyurl.com/zyr58vfs. Because carbon dioxide is odorless, clear, and heavier than air, pipeline breaches like Satartia's that release massive and heavily concentrated amounts of CO_2 can easily poison unsuspecting residents. *Id.*

Fourth, and finally, the Proposed Rule cannot trade in pure speculation to make up for any of these concerns. Recognizing that its wait-for-the-research answer is an inadequate transportation fix, for instance, EPA concludes by saying not to worry about existing pipeline space constraints because we liquefy natural gas, and CO_2 and natural gas are chemically similar. 88 Fed. Reg. at 33,294. This data- and experience-free notion about how industry *might* be able to deal with the problem—one problem of many, to be clear—doesn't cut it. *See Lignite*, 198 F.3d at 934.

d. Carbon use and storage is a misnomer—neither option is viable for a significant portion of affected sources.

Finally, if plants can successfully capture carbon and get it out of the plant, where to store it or how to use it are big questions marks, too.

Just a couple of years ago, the National Petroleum Council remarked that CO_2 "use is the least mature component in the CCUS technology chain." NAT'L PETROLEUM COUNCIL, MEETING THE DUAL CHALLENGE: A ROADMAP TO AT-SCALE DEPLOYMENT OF CARBON CAPTURE, USE, AND STORAGE, CHAPTER TWO: CCUS SUPPLY CHAINS AND ECONOMICS 2-7 (2021), https://tinyurl.com/2t6e5t8f. Critically, "there are significant challenges to overcome before CO_2 use technologies can be deployed at scale." *Id.* at 9-2. These include technology maturation, where "[e]fforts to bridge the gap from concept or laboratory scale to commercial-scale viability are required"; cost and energy efficiency challenges, particularly given the considerable energy needed to convert CO_2 into end-use products; and issues related to carbon's permanence and related indirect impacts. *Id.* at 9-1 to -2. Currently, "[i]ncreased investment in fundamental research and commercialization support is essential to expedite the pace at which CO_2-use technologies would be ready for commercial-scale deployment." *Id.* at 9-2. One problem is that the only viable current use of captured CO_2 is EOR: 95% of captured CO_2 is used for just that. Naomi Klinge, *U.S. representatives propose legislation that would exclude EOR from 45Q tax credits for CCS*, UPSTREAM (Dec. 15, 2021, 6:23 p.m.), https://tinyurl.com/2m9skzdc. And because EPA included no market analysis in the Proposed Rule, it cannot explain what sort of demand there might be for more carbon in EOR—*a lot more* carbon given the proposal's mandate. This failure to account enough for the "marketability of by-products" weighs strongly against finding that this BSER is adequately demonstrated. *Essex*, 486 F.2d at 439.

The proposal also must wrestle with the roadblock that some States are now moving to ban certain uses of captured carbon, including EOR. 88 Fed. Reg. at 33,264 (noting California's recent ban enacted by 2022). And States are becoming more active in this space, *id.* at 33,263-64, which means the unpredictability and volatility for approved uses of captured carbon will likely increase, not decrease. It is just this "uncertainty regarding carbon markets" that caused the DOE's last batch of CCS projects to flop. *See* U.S. GOV'T ACCOUNTABILITY OFF., GAO-22-105111, CARBON CAPTURE AND STORAGE: ACTIONS NEEDED TO IMPROVE DOE MANAGEMENT OF DEMONSTRATION PROJECTS (2021), https://tinyurl.com/3wpp6736 (saying this uncertainty "negatively affected the economic viability of coal power plants and thus these projects"). With similar factors in play now, EPA cannot credibly predict that things will turn out differently now, especially on compressed timeframes and an expanded scale.

So given the lack of use options, many owners will likely have to make do with underground storage. Again, easier said than done (even with the power of a federal regulatory mandate). For one thing, storage options are not widely distributed; acceptable storage locations require good permeability and plume. 88 Fed. Reg. at 33,300. Just a few years ago, EPA noted that over a third of States (19) have "either no/unassessed storage capacity or very limited storage capacity." *Responses to Public Comments*, *supra*. This is why storage cost estimates for CO_2 vary so widely based on location— between ~$5 and $30 a ton. *See*, *e.g.*, Erin E. Smith, The Cost of CO2 Transport and Storage in Global Integrated Assessment 35 (2021) (M.S. thesis, MIT), *available at* https://tinyurl.com/ykykv5bx; *id.* at 29 ("The cost of CO_2 storage is very site dependent because geologic characteristics vary from site to site and injection, labor, drilling, capital, and other costs vary regionally.").

The Proposed Rule provides cold comfort in response to this problem. It offers only a few examples, and they have limited storage experience (by volume). 88 Fed. Reg. at 33,295. EPA also notes a few projects still in testing—an Illinois facility started in 2017 and a North Dakota facility—and future planned projects in North Dakota and Wyoming. *Id.* at 33,295. Ultimately, no project is remotely at commercial scale because, as EPA admits, we're still "furthering the development and refinement of technologies and techniques critical to the" long-term success of storage. *Id.* at 33,295. Right now, the only large-scale sequestration project in the United States is run by the Department of Energy. CONG. RSCH. SERV., R46192, INJECTION AND GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: FEDERAL ROLE AND ISSUES FOR CONGRESS (2022), https://bit.ly/3s25NvJ.

EPA suggests some alternatives to traditional storage options, like storing CO_2 in unmineable coal seams. 88 Fed. Reg. at 33,297. This proposal is yet another idea that "has been demonstrated in small-scale demonstration projects" but never full scale. *Id.* Speculating about the possibility of using other formations like depleted oil and gas fields, *id.* at 33,297-98, is also just that—speculation. And the thought that operators could put new baseload plants near neighboring geological formations and use transmission lines, *id.* at 33,298, fails too. It ignores the "line loss" inefficiencies created whenever transmitting power over distances—a problem EPA recognizes elsewhere, *see id.* at 33,319 n.473, but not here. And it's no solution at all for existing plants that cannot change their physical location. Once again, the Proposed Rule cannot use potential options for a Section 111(b) new-and-modified source rulemaking to justify this Section 111(d) existing source rule.

Acquisition and permitting are also challenges even after (if) the industry answers the "where" problem. State law governs who owns the underground geological formations needed for storage (called "pore space" because the CO_2 settles in small voids in the geological formations called "pores"). But state legal systems governing large-scale injection into pore space are still underdeveloped. When West Virginia updated its carbon sequestration law earlier this year, for example, *see* W. Va. Code § 20-1-1–22, only a handful of other States had laws it could look to as exemplars, *see LPDD Model Law: State Legislation for the Geologic Storage of Carbon Dioxide*, LPDD, https://tinyurl.com/mrxm49tt (last accessed Aug. 5, 2023) (listing other States with CCS-related laws). The vagaries of States' laws and regulations become even more acute when dealing with large CO_2 storage projects, which could have a plume that extends for many square miles and involves many property owners. NAT'L PETROLEUM COUNCIL, MEETING THE DUAL CHALLENGE: A ROADMAP TO AT-SCALE DEPLOYMENT OF CARBON CAPTURE, USE, AND STORAGE, CHAPTER SEVEN: CO_2 GEOLOGIC STORAGE 7-35 (2021), https://tinyurl.com/4eds37m5 ("The issue of pore space legal rights is complicated by the fact that for a large CO_2 storage project, the CO_2 plume may extend over hundreds of square miles, and the pressure buildup extends over an even larger area."). The Congressional Research Service summed it up well: "[T]he transport and storage steps still face challenges, including economic and regulatory issues, rights-of-way, questions regarding the permanence of CO_2 sequestration in deep geological reservoirs, and ownership and liability issues for the stored CO_2, among others." CARBON CAPTURE AND SEQUESTRATION, *supra*.

To be sure, EPA can point to a "detailed regulatory framework" ready to approve CCS permits. 88 Fed. Reg. at 33,296. But the agency is referencing its own *federal* framework, not state law, and the word "detailed" is an understatement. This framework is EPA's Class VI well permitting process, promulgated under the Safe Drinking Water Act. *Id.* at 33,247. This permitting process is painfully slow and intensive, involving loads of documentation and many years' wait time. One article studied the timeline for a single Class VI well application: the permit application was filed in July 2011; three years later in April 2014, EPA issued a draft permit; and EPA finally authorized injection another three years after that when post-construction logging and testing and permit modification had run its course. BOB VAN VOORHEES ET AL., ILL. STATE GEOLOGICAL SURV., OBSERVATIONS ON CLASS VI PERMITTING: LESSONS LEARNED AND GUIDANCE AVAILABLE 3 (2021), https://bit.ly/3KuR0QJ. With about seven years until compliance deadlines start coming due, EPA does not explain how it expects to handle a massive new influx of permitting needs in time for regulated parties to have any assurance they can store the carbon EPA would require them to capture.

Unfortunately, the storage problems do not even stop there. Despite few examples of long-term CO_2 storage to go on, we know there have been problems. In 2011, for example, a non-power plant CCS operation that cost billions of dollars was put on hold because of concerns about the seal of the rock formation used to store the CO_2. *In Salah Fact Sheet*, MIT CC&ST PROGRAM, https://tinyurl.com/fdr76vcc (last visited Aug. 5, 2023); *see also* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CARBON DIOXIDE CAPTURE AND STORAGE (2005), https://tinyurl.com/yh94jbj2 ("CO_2 storage is not necessarily permanent. Physical leakage from storage reservoirs is possible via (1) gradual and longterm release or (2) sudden release of CO2 caused by disruption of the reservoir."). Indeed, many things can go wrong with sequestration: the pressure required to inject CO_2 and replace existing fluids can crack the geological structure; the structures are susceptible to earthquakes and other seismic activity; chemical reactions between the CO_2 and injecting chemicals can increase permeability; and CO_2 can corrode the materials used to seal old fossil-fuel wells. FOOD & WATER WATCH, FACT SHEET: CARBON CAPTURE AND SEQUESTRATION: FOSSIL FUELS' BILLION-DOLLAR BAILOUT (2022) ("FWW Report"), https://tinyurl.com/2rkxmyf2 (citing, among other sources, Adriano Vinca et al., *Bearing the cost of stored carbon leakage*, 6 FRONTIERS IN ENERGY RSCH. Art. 40, at 3 (2018); and S. Holloway, *Storage capacity and containment issues for carbon dioxide capture and geological storage on the UK continental shelf*, 223 J. OF POWER AND ENERGY 239, 241 (2008)). This isn't the picture of "reasonable reliability" that the case law demands. *Essex*, 486 F.2d at 433. And little surprise there: EPA cannot cite examples of successful, commercial, long-term CO_2 storage because they don't exist.

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Many of these issues would sink this BSER on their own. But especially considered "cumulative[ly]," they establish that CCS is not adequately demonstrated. *Nat'l Lime Ass'n*, 627 F.2d at 431. Just consider the confluence of similar issues that confronted the court in *Sierra Club*—the "inherent tension" between pushing "innovative" technology and "adequately demonstrated" technology. 657 F.2d at 341 n.157. Like the dry scrubbers there, CCS may offer "potential advantages" over other greenhouse-gas-reduction technologies. *Id.* But also like dry scrubbers, CCS leaves us with too many unanswered questions like how the technology will work and how much it will cost. These open questions "limit the overall acceptability of" CCS and strongly indicate that it hasn't been adequately demonstrated. *Id.* Worse still, here (like there) "no full scale" examples of the chosen technology are "presently in operation at utility plants." *Id.* EPA bore a heavy burden in *Sierra Club* to explain how its "limited" pilot and prototype testing data could "predict performance in full scale plants throughout the industry." *Id.* All that created "major uncertainty" for about whether dry scrubbing was ready for primetime—and the reviewing court readily said it was not. *Id.* So too with CCS: With sizable questions plaguing every stage of the process, it is not one of those rare emerging technologies that could "conceivabl[y]" be adequately demonstrated. *Id.* EPA should discard it now.

B. Co-firing Is Not A Statutorily Permissible BSER, Either.

As the agency knows, the fuel used in combustion turbines today is overwhelmingly natural gas. Sometimes, operators will add a little pure hydrogen to the natural gas—a process called "co-firing." This can be attractive from an environmental efficiency standpoint because natural gas's chemical structure includes carbon, while pure hydrogen's doesn't. EPA is proposing to require all intermediate and baseload combustion turbines to start co-firing 30% hydrogen by 2032 and baseload combustion turbines to co-fire 96% hydrogen by 2038. The Proposed Rule would also require natural gas plants to buy and burn "ultra-low greenhouse gas hydrogen"—not the hydrogen currently on the market.

Understanding the two types of combustion turbines on the market today and the hydrogen manufacturing process help clarify hydrogen co-firing's significant challenges as a BSER. The first combustion turbine technology is the older diffusion technology, which compresses air, puts it into a combustion chamber, and then adds the fuel and water to the chamber via separate nozzles. (The water is supposed to cool the reaction to ~2600 degrees, the temperature sweet spot for limiting NOx and carbon monoxide emissions.) These systems are expensive. And because of demineralized water requirements, their usefulness is limited in arid locations, like in most of the western States. But on the plus side they have great fuel flexibility. The second technology—the far more common one used today—is the newer dry-low-nitrogen (DLN) approach, which uses staging to premix the compressed air and fuel before they reach the combustion chamber. Premixing slows down the chemical process, leading to less intense flame and heat and therefore less NOx. But DLNs lack operational and fuel flexibility. For its part, hydrogen is manufactured in several ways: methane pyrolysis, reforming/ gasification, and electrolysis. For purposes of its second BSER, the EPA is proposing electrolysis as the relevant manufacturing method because it is the only one that's greenhouse gas free. To oversimplify, electrolysis creates pure hydrogen by separating water molecules' hydrogen and oxygen atoms. But this process is resource-intensive, costing twice the energy we get from burning the pure hydrogen. So the only way the Proposed Rule explains to prevent the BSER from being environmentally counterproductive is to mandate that the hydrogen be produced using ultra-low greenhouse gas methods—that is, with renewable energy.

As explained above, this BSER far exceeds EPA's statutory mandate because it doesn't regulate natural-gas plants as much as require them to become something else entirely—a hydrogen-fired plant. It also goes "beyond the fence line" by claiming most of the proposal's benefits from the way hydrogen is *produced*, not anything about how the power plant itself burns it. Mandating ultra-low greenhouse gas hydrogen as an input is not an "efficiency-improving, at the source measure[]," *West Virginia*, 142 S. Ct. at 2612 n.3, because burning hydrogen emits the same emissions regardless how it's produced—the Proposed Rule's reductions occur during the off-site production process. *See* Emre Gençer, *Hydrogen*, MIT CLIMATE PORTAL (June 23, 2021), https://tinyurl.com/3eu9nvpc ("Unlike most fuels, hydrogen does not produce the greenhouse gas carbon dioxide (CO_2) when burned: instead, it yields water.").

For purposes of the rest of the statutory requirements, it also shares the key flaw that CCS does: Co-firing with hydrogen at anything approaching commercial scale is unheard of. Edison Electric Institute, *supra*, at 5 ("[C]urrently there is a lack of operating [co-firing] projects at scale, both in the United States and abroad, as well as critical open U.S. regulatory, legal, and commercial questions."). So here too, courts will give a "demanding" look at EPA's purported "evidence about the potential benefits and capabilities of [co-firing]." *Sierra Club*, 657 F.2d at 348. And also like CCS, co-firing falls prey to all the predictable "difficult[ies] of justifying" a BSER that does not reflect existing technology but tries to force industry to develop and then use "new technology." *Id.* (saying allowing that sort of BSER would "circumvent[Section 111's] primary statutory goals").

Hydrogen co-firing cannot meet that demanding level of review. To start, just like CCS, little evidence and data supports co-firing as a BSER. The combustion turbines themselves have serious technological limitations—such as co-firing capacity and flashback—and the proposal ignores these problems. Moving past the turbines, it's difficult to see how industry could manufacture enough hydrogen to meet EPA's co-firing goals. And even if it could, it could not transport the hydrogen to the natural gas plants given critical pipeline and storage limitations. All these and other problems have put the economic cost of hydrogen through the roof—an issue that would get exponentially worse considering the other challenges from using the ultra-low greenhouse gas hydrogen the Proposed Rule mandates. And after all this headache, the environmental benefits are far below promised levels. The Proposed Rule does not adequately respond to any of that. Co-firing fails every Section 111(a)(1) factor and thus cannot be a best system of emission reduction.

1. No studies or other evidence adequately demonstrate that hydrogen co-firing is a legitimate BSER.

Hydrogen co-firing is even more embryonic than CCS; to call it "emerging" would give it too much credit. The Proposed Rule sometimes seems to recognize this—like when summarizing industry as having only "a growing interest in the use of hydrogen as a fuel." 88 Fed. Reg. at 33,255. But the gulf between a "growing interest" and an adequately demonstrated technology is huge. "By the very nature of its newness, it [is] inevitably harder for EPA to acquire as precise and complete information about [co-firing] technology" as necessary to choose it as a BSER. *Sierra Club*, 657 F.2d at 348. The Department of Energy recently set out in detail just how undeveloped it currently is. *See* DEP'T OF ENERGY, U.S. NATIONAL CLEAN HYDROGEN STRATEGY AND ROADMAP (2023), https://tinyurl.com/bdzjvdd4. On the ultra-low greenhouse gas hydrogen side of things, for instance, DOE says that the key "components and integrated systems" used to make it "are still in the early stages of scale-up and commercial deployment." *Id.* at 24. Even more concerning, we also don't know hydrogen's "most suitable applications" and "optimal use[s]" within the broader "overarching energy systems." *Id.* at 26. And EPA knows all this because it "consulted with the DOE" on this Proposed Rule. 88 Fed. Reg. at 33,247. Its decision to designate hydrogen co-firing a BSER is thus even more confusing. EPA simply cannot make a fair prediction of cost, reliability, efficiency, and other statutorily required considerations when this technology is still in its earliest stages.

Indeed, the too-limited state of hydrogen co-firing is obvious from the weak co-firing exemplars the proposal offers up. Its primary example is a transition from coal to natural gas, not the technology EPA proposes to require. *See* 88 Fed. Reg. at 33,305. Its second example isn't an example of co-firing at all; it's just a source "designed to transition to 100 percent hydrogen in the future" (and that right now can still co-fire only 5%). *Id.* at 33,305. And scraping the bottom of the barrel, the proposal notes that the New York Port Authority once co-fired 44%. *Id.* at 33,305. None of these short-term or one-time demonstrations are relevant here: for Section 111 purposes, tests must be at least somewhat similar to real-world conditions. *Sierra Club*, 657 F.2d at 341 n.157. Otherwise extrapolating from outliers misses important factors—like long-term damage to combustion turbines from sustained and extensive co-firing.

Yet EPA can point only to "plans" and "projects," "plans to collaborate," and intentions to "begin" construction in this area. 88 Fed. Reg. at 33,305-06. The Proposed Rule lacks real-world evidence or data, leaving just more forbidden speculation and conjecture. *See Lignite*, 198 F.3d at 934. Its proposed plans to manufacture co-firing technology *and* transmission *and* infrastructure tells us that none of these stages of hydrogen co-firing are ready at a commercial scale. 88 Fed. Reg. 33,306. In trying to justify its unreasonably high 30% co-firing number, for instance, EPA cites several manufacturers who say they will make combustion turbines that can co-fire at high numbers. Of course, there's a significant difference between manufacturers predicting they will be able to build a 100% co-firing combustion turbine, *id.* at 33,308, and evidence that concrete, realistic plans exist to do so soon and at scale. The *only* power plant EPA cites that has a concrete plan to get to 100% co-firing says it won't be there technologically until 2045—seven years too late for EPA. 88 Fed. Reg. at 33,308. This lack of evidence puts co-firing firmly in the "purely theoretical or experimental" technologies category. *Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 786.

2. Co-firing is plagued by technological limitations.

We don't see co-firing on anything approaching the level the Proposed Rule would require for a reason: Combustion turbines can't handle the co-firing numbers at EPA's preferred level, and there's no concrete evidence they will be able to, either. Start with the initial requirement to burn 30% hydrogen by 2032. Most combustion turbines on the market today cannot handle anything more than a 5-10% blend; 20% is generally accepted as the absolute technological ceiling. A. Aniello et al., *Hydrogen substitution of natural-gas in premixed burners and implications for blow-off and flashback limits*, 47 INT'L J. OF HYDROGEN ENERGY 33,067, *2 (2022) ("burners designed for natural gas, can only sustain limited hydrogen concentrations, typically 5 to 20% [volume] in the fuel blend"). Even in the best scenarios, a hydrogen volume fraction of 20% is usually the most technology currently can do. *Id.* EPA's 2038 target of 96% hydrogen co-firing fares even worse, because "the highest hydrogen capability marketed for any frame engine with lean premixed combustion is 50%"—and for most systems that percentage is "much lower." Ben Emerson et al., *Hydrogen substitution for natural gas in turbines: Opportunities, issues, and challenges*, POWER ENG'G (June 18, 2021), https://tinyurl.com/bdcmxc8x. Technological impossibility drives to the heart of Section 111's adequately demonstrated standard: If sources cannot burn at the level EPA has set, then the BSER fails on that ground alone. Indeed, *Essex* said that sources must at the very least be able to "approach[]" the BSER EPA establishes, 486 F.2d at 440; no hydrogen co-firing technology we have now comes close.

In its more candid moments, EPA seems to acknowledge the deep uncertainty this proposal faces—exactly how much hydrogen can these combustion turbines handle. 88 Fed. Reg. at 33,244. The Proposed Rule insists in some places that 30% is achievable, *id.* at 33,255, but in others contradicts itself, admitting that we're still only at the demonstration phase of firing 20%, *id.* at 33,305. EPA fails to resolve the tension in these statements. And it begrudgingly acknowledges the massive difficulties inherent to co-firing in DLN combustion turbines, but it tries to brush away these problems by saying it is sure the market is developing a solution, *id.* at 33,311, and then listing various utilities that have publicly announced a desire to burn 100% hydrogen by 2035 to 2045, *id.* at 33,255. But with all EPA's evidence tallied, here is what the Proposed Rule cites to support its co-firing goals: "three utility announcements" and "several"—three—"merchant generators … signaling their intent to ramp up hydrogen co-firing levels." *Id.* at 33,255. A handful of industry desires is not enough to confidently say co-firing is the *best* system of emission reduction. *See Lignite*, 198 F.3d at 934.

At other times, the Proposed Rule misrepresents how much hydrogen combustion turbines can currently co-fire. For example, EPA says that by 2030 manufacturers "will be capable of combusting 100 percent hydrogen" using DLN designs. 88 Fed. Reg. at 33,312. Yet the evidence for this aggressive claim is a single quote from a single article, *id.* at 33,312 n.443, in which a GE executive says the company would continue investing in R&D "to advance the percentage of hydrogen combustion capability *towards* 100% by 2030." Frédéric Simon, *GE eyes 100% hydrogen-fuelled power plants by 2030*, EURACTIV (May 12, 2021), https://tinyurl.com/3zaa9cyy (emphasis added). Indeed, the article's cautious title—that one company is merely "eye[ing]" 100% hydrogen co-firing—gives the game away. So EPA's prediction on perhaps the most fundamental question for this BSER—whether co-firing at the prescribed levels is even technologically feasible—is built on the flimsiest of foundations.

Combustion turbines also face many operational challenges, with two particularly relevant here because hydrogen makes both worse. First is "flashback"—when the flame in the combustion chamber begins traveling up the fuel stream towards the source. 88 Fed. Reg. at 33,311. Hydrogen's flame speed is an order of magnitude greater than natural gas's. So hydrogen flame tends to propagate upstream much faster and can damage certain hardware (the injection system) that would never be in danger if natural gas were the fuel. Aniello et al., *supra*, at *11; KEVIN TOPOLSKI ET AL., NAT'L RENEWABLE ENERGY LAB., HYDROGEN BLENDING INTO NATURAL GAS PIPELINE INFRASTRUCTURE: REVIEW OF THE STATE OF TECHNOLOGY 39 (2022), https://tinyurl.com/4xnakzhs. "Boosting the hydrogen content" to about 50% raises the burner temperature by a third, brings the flame "dangerously" close to the burner, and then causes flashback. Aniello et al., *supra*, at *20. Second, combustion instabilities in modern, low NOx turbines make them prone to many kinds of damaging oscillations during operation, and these oscillations are highly sensitive to ambient air temperature and fuel composition. Introducing hydrogen as a new fuel source will, in many turbines, increase those combustion instabilities that can take a natural-gas plant offline. *Id.* at *2 ("[A]dding hydrogen to standard fuels poses challenges, since it modifies fundamental combustion characteristics that can compromise the fulfillment of safety and pollution standards" (cleaned up)). Both these issues are serious—flashback is a common and well-known problem, and it's one of the "adverse conditions which can reasonably be expected to recur" when co-firing. *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46. The Proposed Rule should have an answer to both concerns to get past the "adequately demonstrated" hurdle. It doesn't.

Another technological limitation: current hydrogen co-firing technology requires a far higher number of manual interventions to keep the hydrogen fuel supply steady than is ideal for plant operations. *See* ELECTR. POWER RSCH. INST. ET AL., EXECUTIVE SUMMARY: HYDROGEN COFIRING DEMONSTRATION AT NEW YORK POWER AUTHORITY'S BRENTWOOD SITE: GE LM6000 GAS TURBINE (2022), https://bit.ly/3Yp5w23. This constant need for intervention is a serious operational problem in and of itself. But it becomes far more acute because DLN combustion turbines are highly sensitive to differences in fuel mixture; in short, co-firing threatens DLN turbines' stability. *Id.* Co-firing also requires many parts of the combustion turbine to be readjusted. *See*, *e.g.*, *id.* (noting that co-firing with hydrogen means the natural gas fuel pressure must increase significantly). And these readjustments create many opportunities for turbines to fail; the Proposed Rule ignores this crucial aspect of its cost analysis, too. All these operational challenges mean that co-firing isn't reasonably reliable or reasonably efficient. *Essex*, 486 F.2d at 433.

3. Sourcing and transporting ultra-low greenhouse gas hydrogen faces serious headwinds.

Yet another reason this BSER hasn't been adequately demonstrated is inadequate fuel supply. By all accounts, it will be nearly impossible for plant operators to get and move enough ultra-low greenhouse gas hydrogen to both comply with the Proposed Rule *and* keep America's lights on.

To start, we have no hydrogen—let alone enough ultra-low greenhouse gas hydrogen—that could meet this BSER. *See* Edison Electric Institute, *supra*, at 6 (noting that EPA should reconsider this BSER "once hydrogen is available as a fuel"). Consider what it would take to replace the natural gas burned in combined cycle units with hydrogen. In 2021, natural gas accounted for 38% of total energy production. See Elizabeth Weise, *Here comes the sun: Wind, solar power account for record 13% of U.S. energy in 2021*, USA TODAY (March 5, 2022), https://tinyurl.com/9tf7pr4d. And combined cycle turbines accounted for 32% of total energy production. EIA, *U.S. electric-generating capacity for combined-cycle natural gas turbines is growing* (Nov. 4, 2022), https://tinyurl.com/yckahkk5. This figure means that combined cycle units consumed roughly 84% of all natural gas burned by the energy sector in 2021. Last year, our nation's energy sector burned 12.12 trillion cubic feet of natural gas. *Natural gas explained*, ENERGY INFO. ADMIN. (Apr. 28, 2023), https://tinyurl.com/4wcnev6m. So combined cycles burned roughly 10.2 (84% of 12.12) trillion cubic feet of natural gas. One cubic foot of natural gas produces 1,036 BTUs, meaning combined cycles produced around 10.6 quadrillion BTUs of energy. How much hydrogen would we have to burn? Our entire hydrogen production—10 million metric tons—is "equivalent to just over 1 quadrillion BTUs per year." https://tinyurl.com/yc58e6zd (Oct. 7, 2021). And 95% of that 10 million metric tons isn't the sort of clean hydrogen that counts for the Proposed Rule. 88 Fed. Reg. at 33,306. In short, America currently produces just .5% of the clean hydrogen we need under the Proposed Rule. The industry would have to close a 99.5% supply gap in just 15 years.

EPA has offered no evidence showing that this gap will close. "Nearly all of" the 10 MMT we produce we use for "refining petroleum, treating metals, producing fertilizer, and processing foods." *Hydrogen Production and Distribution*, DEP'T OF ENERGY, https://tinyurl.com/mtctydav (last accessed Aug. 5, 2023). And industry could not use even the very little left over to comply with the Proposed Rule because it is not the ultra-low greenhouse gas variety EPA prefers. DOE estimates that the market will create 10 additional million metric tons of clean hydrogen by 2030 and 20 total by 2040. 88 Fed. Reg. at 33,309. This amount seems marginally hopeful, but the Proposed Rule doesn't given enough to assess the prediction because it does not explain how DOE gets there. What's worse, even these numbers are possibly irrelevant because EPA is not sure that what DOE calls "clean" hydrogen means the ultra-low greenhouse gas hydrogen it proposes requiring. *Id*. And on top of that, even 20 million metric tons of ultra-low greenhouse gas hydrogen is still just a fifth of our total combined cycle natural gas need—let alone 15 years from now as the electrification trend continues. It's hard to believe that closing this minimum 80% gap would be anything but "exorbitantly costly." *Essex*, 486 F.2d at 433.

EPA admits that "building the infrastructure required to support widespread use of … low-[greenhouse gas] hydrogen in the power sector will take" a long time. 88 Fed. Reg. at 33,283. But this language appears to be code for trying to manufacture an industry from scratch and then propping it up with federal money. America doesn't make much hydrogen, and of what we do make, only 5% fits EPA's definition of ultra-low greenhouse gas hydrogen. *Id.* at 33,306. Indeed, "[o]nly small-scale facilities are currently producing hydrogen through electrolysis." *Id.* at 33,312. EPA also is not just mandating that intermediate and baseload combustion turbines use ultra-low greenhouse gas hydrogen—it proposes defining ultra-low greenhouse gas hydrogen to exclude any hydrogen that comes from a facility that manufactures non-low greenhouse gas hydrogen. *Id.* at 33,328. This distinction means that the existing small hydrogen producers cannot just retool part of their plants or expand their plants to make clean hydrogen; they would have to convert the entire plant. So building an industry from scratch as the proposal would require seems unlikely. Once more, the almost certain lack of hydrogen is one of those "significant variables" that shows a BSER cannot be "adequately demonstrated." *Nat'l Lime Ass'n*, 627 F.2d at 445, 450.

Co-firing also runs into many of the same transportation and infrastructure hurdles as CCS. Pipelines are probably the biggest issue (though the concerns below apply to any infrastructure we use to ship hydrogen, including trucks, trains, and ships). We currently have only 1,600 miles of hydrogen pipeline. 88 Fed. Reg. at 33,308. Compare that to our *300,000 miles* of natural gas transmission pipeline. *Annual Report Mileage for Natural Gas Transmission & Gathering Systems*, DEP'T OF TRANSP. (July 10, 2023), https://tinyurl.com/43j6nmy9. Even if we had enough pipelines, we'd first run into energy inefficiencies caused by "compression" issues—what one veteran chemical engineer working for the Hydrogen Science Coalition called the hydrogen-as-fuel-source "deal killer." Paul Martin, *Is Hydrogen The Best Option To Replace Natural Gas In The Home? Looking At The Numbers*, CLEANTECHNICA, https://tinyurl.com/325j36x7 (Dec. 14, 2020). Before any gas can be moved, it must be compressed. *Id.* Generally, "dense gases are easier … to move than less dense ones." *Id.* Hydrogen is much less dense than natural gas and thus harder to compress. *Id.* So difficult, in fact, that "it takes about *three times as much energy* to compress a MJ's worth of heat energy" in hydrogen than it does in natural gas. *Id.* (emphasis added). And this compression uses not just more energy, but it creates additional capital costs as gas utilities replace or purchase far more powerful and expensive compressors. *Id.* These differences explain why, in part, "we don't move hydrogen around much by pipeline"; in Europe, for example, 85% of hydrogen produced "travels basically no distance to where it's consumed." *Id.*

And what's worse, we can't use the existing natural gas pipeline infrastructure because of a phenomenon called "embrittlement": Hydrogen is the "smallest size molecule that exists," and is quite diffuse (meaning as a molecule it easily breaks apart into its constituent hydrogen atoms).

JEAN-FRANÇOIS LIBERT & GARY WATERWORTH, UNDERSEA FIBER COMMUNICATION SYSTEMS (2d ed. 2016). These characteristics allow hydrogen to permeate hard pipeline metals and plastics much faster than larger, less diffuse molecules like methane-based natural gas. CONG. RSCH. SERV., R46700, PIPELINE TRANSPORTATION OF HYDROGEN: REGULATION, RESEARCH, AND POLICY (2021), https://bit.ly/3OqLBem (saying hydrogen "can also permeate directly through materials used for natural gas distribution faster than methane"). Over time, the hydrogen inside the pipeline microstructure begins causing hairline cracks that, with more time, grow larger. *Hydrogen embrittlement: what is it and how to prevent it?*, DEMACO, https://tinyurl.com/mtchc7f2 (last accessed Aug. 6, 2023). Eventually, if the pipeline isn't replaced, this embrittlement can cause breaks, leaks, or explosions. *Pipeline Transportation of Hydrogen*, *supra* ("Hydrogen can deteriorate steel pipe, pipe welds, valves, and fittings through embrittlement and other mechanisms.").

We know we can send some hydrogen through natural gas pipelines safely—say 1-5% of the total pipeline load. *See* California Public Utilities Commission (CPUC) & University of California, Riverside, *Hydrogen Blending Impacts Study* 107 (July 18, 2022), https://tinyurl.com/4c55hnd4. But once we get to 20%, things get dangerous: Hydrogen blends higher than 20% "increase the risk of gas ignition outside the pipeline." CAL. PUB. UTILS. COMM'N, HYDROGEN BLENDING IMPACTS STUDY 107 (2022) ("CPUC Study"), https://tinyurl.com/4c55hnd4; *see also* PIPELINE TRANSPORTATION OF HYDROGEN, *supra* (agreeing currently technology allows only blending up to 20%). Further, blending at 20% decreases a pipeline's time-to-failure number by nearly 60%. CPUC Study, *supra*, at 59. And really, we just don't know what happens for sure at these higher levels of blending other than that the results are not good. Beyond 2%, we have some knowledge gaps; beyond 10%, the knowledge gap extends to "network management & compression"; at 30%, our knowledge is limited to "distribution, safety, and end-use equipment"; and at 50%, we have basically nothing. *Id.* at 107-08. Where is there broad agreement? That blending at anything like the percentages EPA proposes here is not feasible. *See*, *e.g.*, Zahreddine Hafsi, et al., *Hydrogen embrittlement of steel pipelines during transients*, 13 PROCEDIA STRUCTURAL INTEGRITY 210 (2018) (explaining many reasons that "using pipelines designed for natural gas conduction to transport hydrogen is a risky choice").

In partial recognition of these concerns, the Proposed Rule admits that it would require the wholesale "deployment of new pipeline infrastructure designed for compatibility with hydrogen." 88 Fed. Reg. at 33,314. EPA seems to be setting aside the massive industry and political will that will be needed to get anything like that massive construction effort off the ground and to the finish line in time to meet the Proposed Rule's timelines. EPA seems to be setting aside, too, the litigation roadblocks that tie up existing pipeline projects for years—Congress just passed Section 324 of the Fiscal Responsibility Act to try to get the Mountain Valley Pipeline out of a years-long litigation purgatory, after all. Even so, the costs to build almost wholly "new" "infrastructure" would be astronomical. The Congressional Research Service estimated that even 66,000 miles of CO2 pipeline would cost $170 billion. CARBON DIOXIDE PIPELINES: SAFETY ISSUES, *supra*, at 1. So yet again, the Proposed Rule sits at a crossroads of "exorbitantly costly," *Essex*, 486 F.2d at 433, and downright impossible, *Portland Cement*, 486 F.2d at 402. This situation is "crystal ball inquiry," *Essex*, 486 F.2d at 434, into "purely theoretical or experimental" technologies, *Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 786, at its finest.

4. The cost of co-firing hydrogen is exorbitant.

In large part from logistical challenges like this, co-firing with hydrogen is prohibitively expensive. Even DOE recognizes that "[t]he levelized cost of hydrogen must be reduced significantly" before it can be widely deployed. HYDROGEN STRATEGY AND ROADMAP, *supra*, at 24. "Across applications, costs need to fall significantly compared to their current level to become competitive from a sustainable, market-driven perspective." *Id.* at 25. Hydrogen fuel is not remotely financially competitive with natural gas—it currently costs several times as much. In fact, just buying normal hydrogen costs anywhere from three to six times more than natural gas based on the type of turbine and the cost of hydrogen. HYDROGEN COUNCIL, PATH TO HYDROGEN COMPETITIVENESS—A COST PERSPECTIVE 59 (2020), https://tinyurl.com/yvpddeax.

The price difference is, in part, because of the difficulty and cost of manufacturing hydrogen—and that problem only gets worse if EPA requires combustion turbines to burn less-common ultra-low-greenhouse gas hydrogen. Some of the issues that will inflate ultra-low-greenhouse gas hydrogen's cost include no "distribution infrastructure" and a "lack of manufacturing at scale," as well as "cost, durability, reliability, and availability challenges in the supply base across the entire value chain." HYDROGEN STRATEGY AND ROADMAP, *supra*, at 24. Systemic uncertainty in the hydrogen market has also made stakeholders at every point in the supply chain hesitant to "sign long-term contracts," which in turn inhibits industry growth and increases costs. *Id.* "Storing hydrogen efficiently and safely is also a considerable challenge." *Id.* at 25. As EPA admits, the "adequacy and availability of hydrogen storage facilities" "present obstacles" to using low-greenhouse gas hydrogen long term. 88 Fed. Reg. at 33,308.

The Proposed Rule doesn't take these costs seriously enough for a statute that requires EPA to consider "cost of achieving" emission reductions when determining whether a given technology is "adequately demonstrated." 42 U.S.C. § 7411(a)(1). It says that we should ignore current realities because soon ultra-low-greenhouse gas hydrogen will be "competitive with" the hydrogen that's manufactured. 88 Fed. Reg. at 33,310. But this estimate works only because EPA assumes that every variable will break in its favor—that R&D hits no snags, that federal subsidies work as expected, and on and on. *Id.* at 33, 310. EPA calls this the "more optimistic" outcome. *Id.* Really, it's an unsupported assumption that all the stars will align perfectly. That makes its cost estimates risibly low. For example, the Proposed Rule says the levelized cost of energy increase for combined cycle units will be about "$1.4/MWh and $11/MWh for the 30 percent and 96 percent (by volume) cases, respectively." *Id.* at 33,314. And capital costs will be only 5% higher and non-fuel variable costs will be only 10% higher. *Id.* at 33,313.

These numbers *might* not rise to statute-defying heights if they prove accurate. But that's a big "if." The numbers rely on $9.5 billion investment in hydrogen co-firing—and apart from the general weakness from investment-based-predictions discussed above, the Proposed Rule shows that EPA is not confident that these investments will do what it hopes. 88 Fed. Reg. at 33,309 (saying the investments "*could* translate to" lower costs (emphasis added)). It is also impossible to fully scrutinize these predictions for the more basic reason that EPA hasn't put the subsidies together yet. *Id.* at 33,329. And the Proposed Rule has a wholly impractical answer for the sky-high prices to build out the pipeline network we discussed above: Co-firing plants should just be "located close to the source of hydrogen." *Id.* at 33,314. Most natural gas plants are not. Just one currently operating clean hydrogen manufacturer is located between Nevada and Lake Erie—in Minnesota. *See The Hydrogen Map*, PILLSBURY WINTHROP SHAW PITTMAN LLP, https://www.thehydrogenmap.com/ (last accessed Aug. 6, 2023). But most natural gas plants are in that same hydrogen desert. *See Power Plants in the United States*, ENERGY INFO. ADMIN., https://tinyurl.com/4kjfue76 (last accessed Aug. 6, 2023). And this rule is for *existing* sources, 42 U.S.C. § 7411(d), not a guideline for where operators should put new plants.

Remember too that co-firing aims to replace the backbone fuel of our energy portfolio, natural gas, with a new version of an experimental fuel that currently plays the tiniest of roles in our energy sector. Good reasons (apart from the technological limitations and impossibilities discussed above) explain why hydrogen hasn't caught on already: Hydrogen isn't a natural power source because of "thermodynamic inefficiencies," 88 Fed. Reg. at 33,309, and because it has a "lower energy density of hydrogen compared to natural gas," *id.* at 33,307-08. Put simply, it's not energy efficient—that's why the little hydrogen we currently make is rarely used for co-firing. *Id.* at 33,305. So claiming that we can rearrange a core component of our energy portfolio in a handful of years for the same price we have paid for traditional methods (or modest upgrades to them) takes "optimism" to an unfair level. The Proposed Rule's refusal to seriously grapple with and address these incredible costs is fatal for hydrogen co-firing as a BSER. *Essex*, 486 F.2d at 433.

5. Hydrogen co-firing creates bad environmental side effects.

Finally, co-firing hydrogen creates various environmental issues that flunk the statutory factors. 42 U.S.C. § 7411(a)(1). For example, because hydrogen reduces the hydroxl radical, which destroys other gasses like methane, burning hydrogen indirectly leads to increases in those greenhouse gases. 88 Fed. Reg. at 33,306.

But the biggest issue is NOx emissions. Hydrogen hurts the environment by producing significantly more NOx emissions than natural gas. ETN GLOBAL, HYDROGEN GAS TURBINES 9 (2020), https://tinyurl.com/m95fz5hs ("The higher adiabatic flame temperature of H2 will result in higher NOx emissions if no additional measures are undertaken."). When low levels of hydrogen are blended with natural gas, NOx emissions are somewhat controllable. CHRISTOPHER DOUGLAS ET AL., GA. TECH STRATEGIC ENERGY INST., NOX EMISSIONS FROM HYDROGEN-METHANE FUEL BLEND (2022), at Fig. 1, https://tinyurl.com/yc2jf5fm. We do not, however, have the technology to handle the significant increases of NOx at high levels of blending—especially not the near-100% levels the Proposed Rule contemplates. *See* DEP'T OF ENERGY, DOE HYDROGEN PROGRAM PLAN (2020), https://tinyurl.com/48een8sk. Indeed, co-firing with hydrogen can in some conditions cause up to six times the NOx that pure natural gas does. *See* Mehmet Salih Cellek & Ali Pınarbas, *Investigations on Performance and Emission Characteristics of an Industrial Low Swirl Burner While Burning Natural Gas, Methane, Hydrogen-Enriched Natural Gas and Hydrogen as Fuels*, 43 INT'L J. OF HYDROGEN ENERGY 1194 (2018). And just last year, the University of California press published meta-analyses showing that burning just 20% hydrogen would lead to an almost 10% increase in NO_x emissions. Madeleine L. Wright & Alastair C. Lewis, *Emissions of NOx from blending of hydrogen and natural gas in space heating boilers*, 10 ELEM. SCI. ANTH. 1 (2022).

All this means that "[i]t will be particularly a challenge to achieve even stricter NOx-limits foreseen in the future," ETN GLOBAL, *supra*, at 9. EPA must consider these "counter-productive environmental effects." *Portland Cement*, 486 F.2d at 385. Here though, the agency readily acknowledges that NOx could be a serious issue, 88 Fed. Reg. at 33,312, to the point that there might be so much excess NOx that EPA would need to mandate a new selective catalytic reduction and corresponding scrubber technologies later, *id.* at 33,302. What it doesn't do it propose a BSER that would avoid these issues on the front end—and thus show how *this* rule avoids the "counter-productive" trap. So either EPA does not truly think that sources will adopt this BSER (feeding into the concerns discussed above that the BSER is largely pretextual), or else it has failed to "consider" adequately the statutorily required factors. 42 U.S.C. § 7411(a)(1).

Further hydrogen co-firing will use a lot more water than current technologies—as EPA calculates it, nearly 50% (about 100 gallons) more water per MWh. 88 Fed. Reg. at 33,302. "Just as an example, to run a 60-MW gas turbine on 100% hydrogen and achieve 25 parts per million NOx, you will consume 20 tonnes—or 20,000 liters—of water every hour." Sonal Patel, *Siemens' Roadmap to 100% Hydrogen Gas Turbines*, POWER (July 1, 2020), https://tinyurl.com/bdzzwvuk; *see also* 88 Fed. Reg. at 33,312 n.444 (relying on same article). And the manufacturing part of the process is water-intensive, too: The ratio is 9 to 1 purified water to hydrogen for electrolysis, so co-firing with hydrogen at the proposal's levels would create "water requirements" even "greater" than those for a CCS source. 88 Fed. Reg. at 33,307 n.401. EPA tries to duck this issue by saying "many" new combustion turbines use a dry cooling method, so the additional cooling water requirements are reasonable. But EPA never puts numbers on these assumptions or explains why assumptions for a new-source BSER should translate to an existing-source BSER like this one. More important, EPA elsewhere treats water consumption as a critical factor in its BSER analysis. *Id.* at 33,323 (saying a certain technology has "lower water requirements and therefore could be the preferred technology in arid regions or in areas where water requirements could have significant ecological impacts"). The agency cannot consider other environmental effects when it helps it get to a preferred result and ignore them when the point the other way.

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Co-firing is either technologically and logistically impossible or just exorbitantly and prohibitively costly. Probably the former—but either way it fails Section 111's rubric. Combined with co-firing's significant negative health and environmental effects, and there's no question that co-firing hydrogen is not an adequately demonstrated BSER.

C. Potential federal subsidies cannot fix this otherwise inadequately demonstrated BSER.

Federal subsidies cannot make up the difference between speculative and demonstrated for either CCS or hydrogen co-firing.

The Proposed Rule is peppered with references to Inflation Reduction Act and Infrastructure Investment and Jobs Act money. *E.g.*, 88 Fed. Reg. at 33,246 (using assumptions about IRA money to build the proposal's cost "model[s]"). Both proposed BSER technologies are enormously costly, as explained above. And both hamstring traditional ways utilities raise capital—for example, many power plants make and pay for improvements using unit-operating revenue as collateral. Am. Pub. Power Ass'n, Comment Letter on EPA's Federalism Consultation on Clean Air Act Section 111(d), 111(b), and MATS RTR Rulemakings 4 (Nov. 21, 2022), https://tinyurl.com/vtzspajf. But CCS and co-firing decrease future output, which in turn reduces owners' ability to make improvements through this financing method. This is especially true for single units and smaller systems. 88 Fed. Reg. at 33,302 (noting that units should accommodate less output by simply "scaling larger"). So EPA is forced to admit that the only way this Proposed Rule might work is if federal subsidies are as effective as EPA hopes they will be. *See*, *e.g.*, *id.* at 33,299, 33,300, 33,307. To be sure, both laws do promise sizable subsidies: The IIJA includes billions in proposed infrastructure spending. *Id.* at 33,260-61. And the IRA provides credits of $85 for each metric ton of CO_2 stored in secure geologic formations and $60 for each metric ton of CO_2 used for enhanced oil recovery and injected into secure geologic storage or used in a qualified manner. Pub. L. No. 117-169, § 13104(c), 136 Stat. 1818, 1924-1929 (2020). Even so, these subsidies are not the elixir EPA hopes for.

For one, EPA never explains how it and other federal agencies will use these funds. The IIJA allotted federal agencies around $9.5 billion to help develop hydrogen options, and $12 billion for CCS. Press Release, *Fact Sheet: Biden-Harris Administration Advances Cleaner Industrial Sector to Reduce Emissions and Reinvigorate American Manufacturing* (Feb. 15, 2022), https://tinyurl.com/wemvzy6v; *see also* 88 Fed. Reg. at 33,260 (using same amounts). The Proposed Rule does not explain, though, where this money is going and, more important, what it expects it will accomplish practically—or how fast. Listing spending categories is as deep as it goes. *Id*. Nor do its sources clarify the picture any. For example, EPA says the hydrogen production tax credit "is expected to incentivize" growth of low-greenhouse gas hydrogen, *id.* at 33,261, but its one supporting citation recites IRA changes to the tax credit and summarily concludes that "clean hydrogen will be primed for takeoff through the 2020s," J. LARSEN ET AL., RHODIUM GRP., A TURNING POINT FOR US CLIMATE PROGRESS: ASSESSING THE CLIMATE AND CLEAN ENERGY PROVISIONS IN THE INFLATION REDUCTION ACT 9 (2022), https://bit.ly/45jazn4/.

The issue is that throwing money at problems of time and technological barriers is no solution to the "adequately demonstrated" problem. Consider an analogy to medical research. Like the energy sector with CCS, medical researchers have been studying cures to various diseases for decades. Money may be one limit in those endeavors, but it is not the only one. Suppose that HHS issued a rule compelling hospitals to offer "Alzheimer's-curing" treatments by 2035. The hospitals would likely object because those treatments don't yet exist—but then HHS points to a half trillion dollars in a recent spending bill allocated to Alzheimer's research as proof that the cure will be discovered, tested, and developed by the compliance deadline. Especially with no sense what research or trials this money would fund or what commercial development would look like, the money is no answer to HHS's impossible mandate. After all, this isn't a situation where the cure is in a laboratory somewhere and government dollars can help get it mass produced and into pharmacies. So it would be unreasonable for the agency to require a treatment that may or may not come to fruition, even with strong motivation and funded research conditions to help things along. So too here. Pointing to even huge figures in federal subsidies cannot give reasonable assurance that the market will find solutions (and develop and bring them to scale in time) for the many practical hurdles that face CCS and hydrogen co-firing.

Especially because history gives us plenty of reasons to suspect that subsidies will not work as EPA hopes. The federal government got into the CCS game back in the early 2000s and spent $1 billion on a carbon capture project at a coal plant. But by 2008 DOE had to split the project into three smaller demonstration projects because of "new market realities." CONG. RESCH. SERV., RL33801, CARBON CAPTURE AND SEQUESTRATION (CCS) 27 (2008), https://bit.ly/43SofEg. The American Recovery and Reinvestment Act of 2009 dropped another $3.4 billion into CCS research, but that was a bust, too: out of nine large-scale projects that money funded (including five commercial power plant projects), only two remain operational—and neither is a power plant. U.S. GOV'T ACCOUNTABILITY OFF., GAO-18-619, ADVANCED FOSSIL ENERGY INFORMATION ON DOE-PROVIDED FUNDING FOR RESEARCH AND DEVELOPMENT PROJECTS STARTED FROM FISCAL YEARS 2010 THROUGH 2017 (2018), https://bit.ly/3Oqa6sd; U.S. CONG. BUDGET OFF., FEDERAL EFFORTS TO REDUCE THE COST OF CAPTURING AND STORING CARBON DIOXIDE 4 (June 2012), https://bit.ly/3DNQNUV. Just two years ago, in fact, the GAO released a report criticizing DOE's administration of that program: DOE had given almost "$684 million to eight coal projects, resulting in one operational facility." U.S. GOV'T ACCOUNTABILITY OFF., GAO-22-105111, CARBON CAPTURE AND STORAGE: ACTIONS NEEDED TO IMPROVE DOE MANAGEMENT OF DEMONSTRATION PROJECTS (2021), https://tinyurl.com/3wpp6736 ("GAO Report"). These CCS projects were "high-risk," GAO said—chiefly because DOE rushed the process. *Id.* DOE also "expedited time frames," bypassing cost controls and spending far more on projects than intended, and kept supporting projects that failed to hit key milestones. *Id.* With compliance deadlines only a handful of years away if EPA finalizes this proposal, we can expect similarly rushed conditions here. And congressional oversight is key to avoiding CCS projects that have "little likelihood of success," *id.*, but it's unclear how much and what kind of oversight will come with the federal dollars EPA clings to. Nor does the Proposed Rule point to any other features of this round of subsidies that suggest it will be more effective than the first billion DOE mismanaged.

Instead, CCS may likely remain—despite extravagant financial support—one of those technologies that stays "one decade away" from being ready. Alfonso Martínez Arranz, *Hype among low-carbon technologies: Carbon capture and storage in comparison*, 41 GLOBAL ENVIRONMENTAL CHANGE 124, 130 (2016). As GAO put it, many of DOE's chosen projects were abandoned because of various "factors affecting their economic viability"—even with hundreds of millions of federal dollars propping them up. GAO Report, *supra*, at 11.

Further, 45Q tax credits are difficult to get. EPA seems to presume an essentially 100% take rate, 88 Fed. Reg. at 33,261 (including IRA credits in cost analysis because the agency was "assuming" various requirements would be "met"). But not all regulated parties will be able to jump through each statutory and regulatory hoop. To get 45Q money, applicants must begin constructing CCS by 2033, after which they have 12 years to collect their tax credits. 26 U.S.C. § 45; *see also Instructions for Form 8933*, I.R.S. (Dec. 2022), *available at* https://bit.ly/3qjp5My. Applicants must meet capacity requirements (produce 18,750 tons annually and capture at least 75% of the CO_2 emitted), and they must pay prevailing wages and limit the number of hours that apprentices work at their facilities. 87 Fed. Reg. 73,580 (Nov. 30, 2022). And for applicants that choose to tie beginning construction to spending 5% of the total costs for the project, 87 Fed. Reg. at 73,582, they must be mindful that overrun project costs do not mean that initial spend slips under 5%—in that case, they do not qualify for the credit. I.R.S. Notice 2018-59, 2018-28 I.R.B. 196, *available at* https://bit.ly/3Qts13P.

A "continuous program of construction involves continuing physical work of a significant nature" must persist through all of this—no voluntary gaps allowed. I.R.S. Notice 2018-59, *supra* § 6. If applicants are updating old facilities rather than building new—like the applicants who would be seeking the credit in connection with trying to satisfy *this* rule—they get the 45Q credits only if the new components used in the update cost at least four times the value of the used components. 86 Fed. Reg. 4,728, 4,736 (Jan. 15, 2021). Facilities also have myriad miscellaneous rules, like penalties for funding CCS construction with tax-exempt bonds. *I.R.S. Instructions for Form 8933*, *supra*. And the I.R.S. is still working out much of its 45Q regulations. 86 Fed. Reg. at 4,753 ("Section 45Q requires regulations for determining adequate security measures for the secure geological storage of qualified carbon dioxide … standards for recapture of section 45Q credits, standards for determining what is a qualified facility for purposes of meeting certain minimum carbon capture thresholds, and standards for carbon dioxide utilization.").

These conditions are likely part of the reason that even though 45Q credits have been around since 2008, we still have only a few CCS facilities—and zero in commercial-scale facilities in the energy sector. Market forces can easily destroy 45Q plans, too. *See* Wamsted & Schlisse, *supra* (discussing this phenomenon in Petra Nova context). Indeed, EPA never discusses or analyzes how many entities already get 45Q credits, how many have applied before or will likely apply, or what applicants' success rate might be. So little surprise to find a wide divergence of predictions by federal entities about how successful 45Q credits will be—nor that EPA is more bullish than the others. The Joint Committee on Taxation estimates that 45Q credits will lead to only 20 million metric tons of carbon captured between 2018 and 2027 yet cost about $700 million. *See* FWW Report, *supra*, at 3. The Congressional Budget Office estimates anywhere from 9 to 13 million metric tons captured a year for ten years after the IRA, with a $3.2 billion price tag. *Id.* Yet EPA estimates over 40 million metric tons on average from 2028 to 2042, cost unknown. 88 Fed. Reg. at 33,409.

What's more, the Proposed Rule does not account for the potential that this money—or at least a large part of it—could go away if political winds or agency leadership shift. This is a politically fragile budget item, and it's foolhardy to shore up significant holes in the agency's BSER analysis with it.

Of course, all this is not to say that federal money cannot play any role in the analysis. Theoretically, federal subsidies could help establish a technology that *later* forms a BSER. But that's the key: EPA is going in the wrong order. It cannot pick a currently speculative technology and trust federal dollars to take it from imaginary to adequately demonstrated. Federal credits and subsidies are not a Section 111 cheat code to skip the statute's requirements. EPA chose to use emerging technologies as BSERs, so it will have to stand them up against the "demanding" standard to justify each of its predictions. *Sierra Club*, 657 F.2d at 348. Imprecise guesses about what a lot of money can do quickly doesn't make things any more concrete.

IV. The Proposed Rule Is Arbitrary And Capricious.

Even if EPA had statutory authority to move forward with the Proposed Rule, other principles of reasoned rulemaking would still stand in the way. A reviewing court may hold a rule unlawful or set it aside under the Administrative Procedure Act if it is arbitrary and capricious. 5 U.S.C. § 706(2)(A). And "[a]rbitrary and capricious simply means unreasonable." *Sithe/Indep. Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 n.2 (D.C. Cir. 2002). Finalizing this proposal would be unreasonable for several reasons. The significant technological hurdles and unbalanced cost-benefit analyses discussed above all apply here, too—Congress made doubly sure EPA would have to consider factors like these by writing them into the primary statutory text, but they also render the proposal arbitrary and capricious. We end this comment by emphasizing three additional concerns to add to that mix. First, this proposal would devastate grid reliability even as our electricity demands and vulnerabilities increase. Second, it undermines EPA's commitment to environmental justice and vulnerable communities rather than advancing it. And third, it turns on unreasonable predictions about market developments. "An agency engaged in reasoned decisionmaking may not ignore 'an important aspect of the problem.'" 88 Fed. Reg. at 33,316 (quoting *Motor Vehicles Mfrs. Ass'n v. State Farm Auto Ins.,* 463 U.S. 29, 43 (1983)). So for these reasons too, we urge EPA to reconsider.

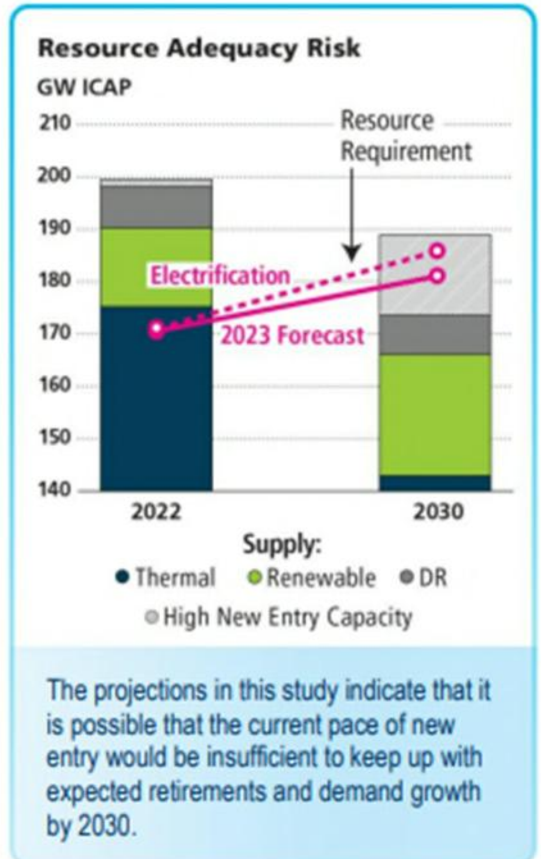
A. The Proposed Rule Would Devastate Long-Term Grid Reliability.

The Proposed Rule is more than a thumb on the scale for a too-quick transition to a renewables-centered market—as explained above, it *forces* the electricity-generating market to make that leap. Moving at the pace EPA wants to require is a recipe for grid failure.

Nobody disputes that grid reliability is crucial—not even EPA. *See*, *e.g.*, 88 Fed. Reg. at 33,243. But the confluence of at least three factors shows that grid reliability is especially fragile right now—and the Proposed Rule will exacerbate that problem. First, demand for electricity will continue increasing in the next few decades. Besides normal population growth, behind-the-scenes components of our increasingly electrified society, like data centers or crypto-currency mining, rely on the electricity grids in ever-increasing measure. And this is hardly EPA's only venture that will tap an already-strained system: Perhaps most obviously, EPA is also looking to replace internal-combustion-engine vehicles with electric vehicles. All of these factors will combine to increase electricity demand by almost 40% by 2035. Katie Brigham, *Why the electric vehicle boom could put a major strain on the U.S. power grid*, CNBC (July 7, 2023, 11:43 a.m.), https://tinyurl.com/4vrynmu7 (noting that California alone will have to spend $50 billion to keep their grid reliable).

Second, according to the EPA, as climate change worsens extreme weather events will become more common. 88 Fed. Reg. at 33,249. "[C]hanges in the frequency and intensity of heat waves, precipitation, and extreme weather events; rising seas; and retreating snow and ice," *id.*, would also stress the grids more than average.

And third, federal and state policies are already pushing a significant number of fossil-fuel plants into retirement over the next 15 years—mostly coal-fired units. For example, the recent effluent limitations guidelines rule, which would limit wastewater discharges from power plants, is expected to cause nearly 10,000 MW of retirements by the year 2028 alone. *Today in Energy*, ENERGY INFO. ADMIN. (Nov. 7, 2022), https://tinyurl.com/598952xm. We're already at a place where "[r]etirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chains, whose long-term impacts are not fully known." PJM, ENERGY TRANSITION IN PJM: RESOURCE RETIREMENTS, REPLACEMENTS & RISKS 1 (2023), https://tinyurl.com/4sa3ez9z.[2] PJM's analysis of its portfolio "shows that 40 GW of existing generation are at risk of retirement by 2030, including 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements." *Id.* at 2. All this is, together, a fifth of PJM's capacity. *Id.* And most of these "thermal" resource retirements are coal plants. The graphic to the right shows how these retirements will put the PJM in real jeopardy. *Id.*



These retirements would come at a time when grids around the country are already straining due to population and economic growth and increased electrification. Take South Carolina for example. Several times this past winter, South Carolina's cooperatives nearly had to cut power to members on several extremely cold days around Christmas. And some South Carolina utilities had to do just that—cutting power to industrial and residential customers. Similar lack of generation capacity caused problems in many other States this last winter as well. *See, e.g.*, Robert Zullo, *Another winter storm strained the electric grid; experts say it's time to fix transmission lines*, IND. CAP. CHRON. (Jan. 3, 2023, 6:00 a.m.), https://tinyurl.com/4mjstvuj.

Fossil fuels are crucial to maintaining grid reliability. As PJM's graphic shows, over the next ten years renewables will begin to dominate our regional transmission organizations' balance sheets—especially if the Proposed Rule moves ahead. But renewables are a nightmare for grid reliability because they're inconsistent: Where can consumers turn when the sun isn't shining and the wind isn't blowing? The answer is coal and natural gas turbines. They are efficient, and many natural gas units have short ramp up times, meaning they can be started and stopped more easily

[2] PJM is the regional transmission operator in charge of electricity transmission in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

than other sources. At this point and into the foreseeable future, renewables *need* natural gas to be successful. N.Y. IND. SYS. OPERATOR INC., NAESB GAS ELECTRIC HARMONIZATION FORUM SURVEY COMMENTS (2021), https://bit.ly/3QxsBxw ("With the increasing number of intermittent electricity resources being installed and increasing variability in electric load, natural gas-fired power plants will be called on to utilize their fast start and quick ramping capability to respond and serve as a backstop to maintain the reliability of the power grid."). That's why since 2015 most simple cycle turbines have been built in Texas, California, and Oklahoma—because those areas have high penetration of renewables. Pretty much everyone agrees natural gas will be important no matter when and how fast we transition to more renewables. *See* ELECTR. POWER RSCH. INST., STRATEGIES AND ACTIONS FOR ACHIEVING A 50% REDUCTION IN U.S. GREENHOUSE GAS EMISSIONS BY 2030 (2021), https://tinyurl.com/2wzjfkvy; CONSUMERS ENERGY, 2021 CLEAN ENERGY PLAN 8 (2021), https://tinyurl.com/mvbw556f. Indeed, California's infamous brownouts are a cautionary tale of what happens when a grid actively tries to eradicate natural gas as a supplement or backstop energy source. *See* Sammy Roth, *California declared war on natural gas. Now the fight is going national*, L.A. TIMES (Feb. 9, 2023, 6:00 a.m.), https://tinyurl.com/47kv7amc. Any reasonable federal policy "must reflect this reality" that "[n]atural gas is the reliability fuel that keeps the lights on." N. AM. ELECTR. RELIABILITY CORP., 2021 LONG-TERM RELIABILITY ASSESSMENT (2021), https://bit.ly/3DM9SqE.

Coal also plays an important grid-reliability role—especially in cases of extreme weather when natural gas can be hard to transport. For example, during the Bomb Cyclone in January 2018, 42% of the PJM region's electricity was generated through coal because natural gas supply problems were driving unusually high outages. Paul Bailey, *Am. Coalition for Clean Coal Elec., MISO, PJM and the Bomb Cyclone: Two Case Studies for Why We Need a Coal Fleet*, AMERICA'S POWER (Feb. 14, 2018), https://bit.ly/43WJ55y (last accessed Aug. 7, 2023). Coal's dependability makes it unreasonable to count it out as a significant portion of our energy portfolio. So in targeting coal and natural gas for elimination at rates the grids cannot sustain, the Proposed Rule is pushing our energy stability off a cliff and snatching away its parachute.

And consider the combined effect of all the anti-fossil-fuel actions EPA has taken over the past few years and plans to take soon: effluent limitations guidelines, coal combustion residuals, NAAQS for particulate matter, a federal implementation plan for ozone, vehicle-fleet electrification, and more. The cumulative effect of these and other anti-fossil-fuel actions devastates grid reliability. The less diverse market-driving mandates like these make our energy portfolio, the more vulnerable we are to unexpected *and* predictable energy needs. Our residents need electricity to survive extreme weather, for instance, and that's precisely when a fossil-fuel-free grid will be the weakest and most vulnerable. *See* OFF. OF ENERGY, POL'Y AND INNOVATION & OFF. OF ELECTR. RELIABILITY, FERC, WINTER ENERGY MARKET AND RELIABILITY ASSESSMENT 2022-2023 18 (2022), https://bit.ly/44YCZmi ("[A]lthough all regions are expected to maintain adequate reserve margins through the winter, reserve margins do not guarantee reliable operations, especially during winter."). This is all exacerbated because both BSERs in the Proposed Rule target the highest-producing fossil-fuel plants—the workhorses of the grid. *See*, *e.g.*, 88 Fed. Reg. at 33,302 (noting that net power output is projected to fall by over 10% with co-firing).

The Proposed Rule also all-but promise to decimate grid reliability through not only its BSERs, but also through its subcategorization scheme. Under previous Section 111 regulations, EPA regulated based on two categories of plants: baseload and peaking. Now EPA wants to create an "intermediate" category that applies to combustion turbine units running around 20-50% of capacity. 88 Fed. Reg. at 33,322. And sources in this intermediate category will have to co-fire 30% hydrogen by 2032. *Id.* This framework will likely put many utilities in a bind.

Consider this example: Remember that new simple cycle natural gas combustion turbines are used mainly to supplement renewables. *See* 88 Fed. Reg. at 33,278. Let's say a utility gets a simple cycle turbine to use as a peaking resource—around 10-15%. But now suppose that for whatever reason the renewables in its portfolio don't perform as planned. In a normal situation, the utility would provide consistent and reliable generation and distribution by pushing the turbine up to and over the peaking line into the intermediate category. But under the Proposed Rule's regime, slipping over that line would trigger the Proposed Rule's 30% co-firing requirement—putting them in an impossible spot technologically and financially. A utility in that position would struggle during unexpectedly low-supply or high-demand situations—especially smaller utilities supported by a single plant. But on the other side of the calculus are state regulations that require utilities to provide electricity consistently, and regional transmission organizations have similar load and adequacy requirements for their load-responsible entities. *See*, *e.g.*, David Eggert, *Will new rules for Michigan utilities force a solution?*, CRAIN'S DETROIT BUS. (May 30, 2023, 10:00 a.m.), https://tinyurl.com/4chzvv7m (noting that for the first time in 20 years Michigan's Public Service Commission "lowered the threshold for what is considered unacceptable performance during outages, and boosted bill credits for customers who go without electricity and made them automatic"); Southwest Power Pool, Inc., *Load Responsible Entity for Reserve Margin Obligation* (June 2015), https://tinyurl.com/5b8ad7a9 (a regional transmission organization explaining some of its requirements for participating power plants).

In short, utilities in high-demand or other stressed states face a no-win scenario. And EPA's own numbers show that this scenario is not hypothetical. "Between 2015 and 2021," it says of the on-average 16 simple cycle turbines that came online every year, "an average of six operated" above 20% capacity factor "and thus would be considered intermediate load combustion turbines." 88 Fed. Reg. at 33,288. The number of simple cycle turbines pushed up to and past that 20% barrier will only increase as more renewables come online and simple cycle turbines must pick up the slack.

Further, gutting grid reliability would have damaging secondary effects. Electricity is a crucial ingredient in economic development—everything from factories to office buildings to universities need it. That's why power availability and energy rates are often a key factor in major construction efforts. For example, when Ford Motor Company set out to open a massive new facility a few years ago to build F-Series pickups and electric vehicles, it chose Tennessee over Michigan—in part because Michigan lacked reliable, cheap energy. *See* Taylor DesOrmeau, *Ford didn't give Michigan shot at new electric plants, Whitmer says*, MLIVE (Sept. 29, 2021, 4:49 p.m.), https://tinyurl.com/yc25wvw7. Businesses seek predictability before major investments—especially about key fixed costs like energy inputs. So grid reliability is a non-negotiable part of a thriving economy—making this proposal even more suspect.

The Proposed Rule does not adequately account for any of this. Indeed, EPA underestimates how important combined cycle baseload units will be for grid reliability going forward. In trying to minimize the effects of the Proposed Rule, EPA notes that new combined cycle baseload builds (against which the CCS and co-firing BSERs would chiefly be applied) represent only "14 percent of all new generating capacity built in the US." 88 Fed. Reg. at 33,303. So, the implication goes, even if these BSERs shut things down, it's only 14%. *Id.* But this analysis confuses generation *capacity* with actual *generation*. Remember that combined cycle baseload units are the workhorses of the EGU world; they run at least 50% of the time, and usually much more than that. Simple cycle units, on the other hand, usually run at around 10-15% of their capacity. So a power plant could install three to five simple cycle units and would likely generate the same power as one combined cycle unit—despite having several times the generation capacity. That's why actual generation is the proper unit to evaluate the proposal's effects on the energy sector. And there's no question that this rule would target most harshly the units that do the most generating.

B. The Proposed Rule Sets Back Environmental Justice.

EPA defines "environmental justice" as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies." *Environmental Justice*, EPA, https://tinyurl.com/2nzfw93r (last accessed Aug. 6, 2023). President Biden's Administration has emphasized as environmental justice as one of its key priorities. *See* Exec. Order No. 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All, 88 Fed. Reg. 25,251 (April 26, 2023), https://bit.ly/3Ys5mXQ. Among other things, it has promised to "build upon and strengthen its commitment to deliver environmental justice to all communities across America." *Id.*

Even so, this proposal wouldn't help the groups it aims to, and it would hurt others, like the rural poor. For one thing, raising energy costs are always a regressive tax. *See Low-Income Community Energy Solutions*, DEP'T OF ENERGY, https://bit.ly/44YqhUA (last accessed Aug. 6, 2023) (noting that lower income households pay nearly three times as much of their income towards electricity costs, 8.6%, compared to high income households' 3%). And given CCS's and hydrogen co-firing's exorbitant costs, this would be an especially steep regressive tax.

For another, the fossil-fuel industry supports millions of blue-collar jobs—at coal mines in Kentucky and West Virginia, to natural gas fields in Texas and Louisiana, to oil fields in North Dakota and Alaska. These workers' families suffer when policies like this "turn the screws on fossil fuels." *The US EPA's proposed regulation could help to kill off fossil-fuel plants. Good on it*, NATURE (June 13, 2023), https://tinyurl.com/bddt68yx (editorial, praising the Proposed Rule for "help[ing] to kill off fossil-fuel plants" because "[e]xpanding clean energy isn't enough to combat the climate crisis"). As we already noted, even the EPA (under)estimates this job loss at 25,000 recurring job-years, *see* REGULATORY IMPACT ANALYSIS, *supra*, at 5-17, while other commenters put total direct job loss close to 275,000 and indirect job loss over 1 million, *see* Int'l Bhd. of Boilermakers, *supra*, at 14-15. Moving to the city, CCS systems' massive footprint functionally doubles the amount of already too-limited urban space utilities would need. And as even EPA admits, bringing hydrogen into and burning it in densely populated areas could be problematic because we have no idea how the technology would interact with urban environments. 88 Fed. Reg. at 33,286. As already explained, though, we do know that the increased NOx emissions will hurt these urban communities.

Further, despite EPA's claims to have "carefully considered" environmental justice concerns, it must admit that representative groups still strongly oppose CCS on environmental justice grounds. 88 Fed. Reg. at 33,247. Private interest groups who strongly agree with EPA's anti-fossil fuels mission have long been skeptical of CCS for many reasons we have raised, among others. *See*, *e.g.*, Env't Def. Fund, Comment Letter on Carbon Capture, Utilization, and Sequestration Guidance – Docket No. CEQ-2022-0001 (Apr. 13, 2022), https://tinyurl.com/8n4sjxs5 (noting "valid" and "nontrivial" "environmental justice and equity challenges posed by even responsible [CCS] deployment"); Press Release by Climate Justice Alliance, *Climate Justice Alliance Warns Carbon Capture & Sequestration, Hydrogen Would Harm Frontline Communities & Perpetuate Climate Crisis Despite Ambitious 90% Cuts to Power Plant Carbon Emissions* (May 11, 2023), https://tinyurl.com/mr4c4292 ("It is shameful that … the EPA is mandating policies … at the expense of Black, Brown, and Indigenous communities. Carbon capture technology and hydrogen will increase local air pollution, taint clean drinking water … and raise energy bills for families nationwide."). Even this White House's Environmental Justice Advisory Council listed CCS as two example of climate change solutions that "will *not* benefit a community." WHITE HOUSE ENV'T JUST. ADVISORY COUNCIL, FINAL RECOMMENDATIONS: JUSTICE40 CLIMATE AND ECONOMIC JUSTICE SCREENING TOOL & EXECUTIVE ORDER 12898 REVISIONS (2021), https://tinyurl.com/2zzfcctx (cleaned up) (emphasis added).

Especially when added to the many other reasons to proceed with caution here, the costs to both rural and urban lower-income communities make it unreasonable to press ahead with the Proposed Rule.

C. The Proposed Rule Relies On Unreasonable Predictions About Technology 7, 9, 13, or 17 Years From Now.

Both CCS and hydrogen co-firing turn on predictions about the state of technology well over a decade from now (as we already explained, they do not reflect the state of the market *now*, or even soon). But who could honestly pretend to know what technology will look like then? History is filled with examples of unexpected events and disruptive technologies upending shaky predictions like EPA's here. Seventeen years ago, Lehman Brothers had 25,000 employees and the most popular email domain was Yahoo!. From recent consumer technologies like broadband or iPhones or ride share apps, to more behind-the-scenes developments like fuel injection devices or semiconductor chips, the world looks very different five years after each of these innovations than it did five years before them.

The energy space is no different. In 2012, for instance, the International Energy Agency predicted that coal would continue dominating the energy sector "for the foreseeable future" and that commercially viable CCS technology would have to develop within the next decade—which ended a year ago. INT'L ENERGY AGENCY, TECHNOLOGY ROADMAP—HIGH-EFFICIENCY, LOW-

EMISSIONS COAL-FIRED POWER GENERATION (2012), https://tinyurl.com/bd8fydyz. EPA itself noted in the Proposed Rule that the unforeseen fracking explosion in the late 2000s transformed the energy sector. 88 Fed. Reg. at 33,257. So if EPA (or others) had tried to predict in 1998 what America's energy-production sector would have looked like in 2015, it would have been dead wrong. Take combined cycle turbines as another example. EPA admits that in 2015 it assumed that simple cycle turbines would play a "*unique* role" in grid reliability that combined cycle turbines couldn't—that is, as peaking load units. 88 Fed. Reg. at 33,320 (emphasis added). The CPP's BSER reflected that assumption. But because of unforeseen technological advancements—improvements in "ramp rates" and integration with renewable and storage projects—EPA's assumption then was quickly proved wrong, to the point that *this* Proposed Rule suggests a fundamental shift in a new direction. 88 Fed. Reg. at 33,320. EPA has not adequately explained why this time is any different when it comes to predictions, critical to the proposal's success, that speculate years into the future.

Crafting BSERs based on these extended timelines is also unreasonable because it unnecessarily forces companies to make critical decisions with too little information. Deadlines in 2030 are not that far from an industry-planning standpoint. Companies will have to start making critical and long-term investment and operational decisions now in preparation for that date. Everything from permitting to construction an especially long time in the energy sector, and decisions in this space incorporate a staggering number of variables. Josh Saul, Cailey LaPara & Jennifer A. Dlouhy, *Permits for US Energy Projects Are So Bad Unlikely Allies Emerge*, BLOOMBERG (June 7, 2023, 4:00 a.m.), https://tinyurl.com/bdfcvtv9 (saying that among a "thicket of regulations," a permit is the hardest part of installing a new "power line or" "gas pipeline," and the "regulatory gauntlet … can consume more than a decade"). So finalizing the Proposed Rule will force companies to make potentially uneconomic and consumer-unfriendly decisions based on technology and market conditions that may or may not develop as EPA predicts.

Courts have been skeptical of too rosy or unsupported predictions in the Section 111 context before. Recall *Sierra Club*'s footnote 157's concern about treating "innovative" or "emerging" technologies as "adequately demonstrated." 657 F.2d at 341 n.157. As explained already, the BSERs here don't even meet that standard. Of course, EPA can project somewhat into the future—it must. *See Portland Cement*, 486 F.2d at 391; *Lignite*, 198 F.3d at 934. But its projections and predictions must be "fair[]," *Portland Cement*, 486 F.2d at 391—and a technological projection's "fairness" diminishes in proportion to how much is being projected and over how long a timeframe. So if EPA, say, predicts how much of an established scrubber solvent will be available next year, it's likely on safe ground. Predicting how many miles of CO_2 pipeline will be available in 2028 is much more difficult going. And projecting how embryonic, nascent industries like CCS and hydrogen may grow over the next nine-to-twelve years is even more treacherous. As noted above, EPA does not have case law on its side for this agency equivalent of fortune telling. It would have to provide much stronger bases to give a reviewing court confidence in its predictions—and to make the decisions it wants to force on industry prudent.

Perhaps all the current indications that CCS and co-firing are not feasible options will prove wrong with time. But based on the information EPA marshals *now*, it is unreasonable to pin rulemaking of this scope on predictions so little grounded in current realities.

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It was only a year ago that the Supreme Court reminded EPA that Section 111 has limits. And only a few weeks ago, the Court reaffirmed *West Virginia*'s holding, reiterating that agency programs of "deep economic and political significance" force courts to assess carefully whether Congress departed from the default rule that it intends to keep questions like that "for itself." *Biden v. Nebraska*, 143 S. Ct. 2355, 2375 (2023) (cleaned up). The Proposed Rule falls in that same category. EPA has also chosen BSERs that do not accord with any fair sense of "adequately demonstrated." It has flouted the other statutory factors. And it has signaled that it does not reasonably believe that finalizing the rule will lead to CCS and co-firing on a mass scale. At bottom, the Proposed Rule seems to be another attempt to force fossil-fuel-fired plants to stop producing or else subsidize different forms of generation. But EPA could not reshape what sources are and aren't allowed to comprise the nation's electricity-generating sector through the CPP—and it cannot through this effort, either. For the sake of our residents, businesses, and sovereign interests, we urge EPA to reevaluate the Proposed Rule in keeping with Section 111's limits and the bounds of reasoned rulemaking.

Sincerely,

Patrick Morrisey
West Virginia Attorney General

Steve Marshall
Alabama Attorney General

Tim Griffin
Arkansas Attorney General

Christopher M. Carr
Georgia Attorney General

Raúl Labrador
Idaho Attorney General

Todd Rokita
Indiana Attorney General

Brenna Bird
Iowa Attorney General

Daniel Cameron
Kentucky Attorney General

Jeff Landry
Louisiana Attorney General

Lynn Fitch
Mississippi Attorney General

Andrew Bailey
Missouri Attorney General

Austin Knudsen
Montana Attorney General

Mike Hilgers
Nebraska Attorney General

John Formella
New Hampshire Attorney General

Dave Yost
Ohio Attorney General

Gentner F. Drummond
Oklahoma Attorney General

Alan Wilson
South Carolina Attorney General

Marty Jackley
South Dakota Attorney General

Angela Colmenero
Provisional Attorney General of Texas

Sean D. Reyes
Utah Attorney General

Jason S. Miyares
Virginia Attorey General