ORAL ARGUMENT SCHEDULED ON APRIL 17, 2017

No. 15-1381
(and consolidated cases)

**IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

STATE OF NORTH DAKOTA, ET AL.,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

Respondents.

On Petitions for Review of Final Action
by the United States Environmental Protection Agency

RESPONDENT EPA'S BRIEF

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DATED: December 14, 2016
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CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

Pursuant to D.C. Circuit Rule 28(a)(1), the undersigned counsel certifies as follows:

A. Parties and Amici.

All parties, intervenors, and amici appearing in this Court are listed in the Final Form Opening Brief of Non-State Petitioners, filed Feb. 3, 2017 (Doc. #1659209).

B. Rulings under Review.

The final agency actions under review are: Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule, 80 Fed. Reg. 64,510 (October 23, 2015); and Reconsideration of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, 81 Fed. Reg. 27,442 (May 6, 2016).

C. Related Cases.

In an order entered on March 24, 2016, this Court severed the case titled Biogenic CO_2 Coalition v. EPA, et al., No. 15-1480, from these consolidated cases, pending further administrative proceedings.

In addition, the following consolidated cases pending before the Court challenge a related agency action: State of West Virginia, et al. v. EPA, et al., No. 15-1363; State of Oklahoma, et al. v. EPA, No. 15-1364; International Brotherhood of Boilermakers, et al. v. EPA, No. 15-1365; Murray Energy Corporation v. EPA, et al., No. 15-1366; National Mining Association v. EPA, No. 15-1367; American Coalition for Clean Coal Electricity v. EPA, No. 15-1368; Utility Air Regulatory Group, et al. v. EPA, No. 15-1370; Alabama Power Company, et al. v. EPA, et al., No. 15-1371; CO_2 Task Force of the Florida Electric Power Coordinating Group, Inc. v. EPA, et al., No. 15-1372; Montana-Dakota Utilities Co. v. EPA, No. 15-1373; Tri-State Generation & Transmission Association v. EPA, No. 15-1374; United Mine Workers of America v. EPA, No. 15-1375; National Rural Electric Cooperative Association, et al. v. EPA, No. 15-1376; Westar Energy, Inc. v. EPA, et al., No. 15-1377; NorthWestern Corporation v. EPA, et al., No. 15-1378; National Association of Home Builders v. EPA, et al., No. 15-1379; State of North Dakota v. EPA, No. 15-1380; Chamber of Commerce, et al. v. EPA, et al., No. 15-1382; Association of American Railroads v. EPA, No. 15-1383; Luminant Generation Company, et al. v. EPA, et al., No. 15-1386; Basin Electric Power Cooperative v. EPA, et al., No. 15-1393; Energy & Environment Legal Institute v. EPA, No. 15-1398; Mississippi Department of Environmental Quality, et al. v. EPA, et al., No. 15-1409; International Brotherhood of Electrical Workers v. EPA, No. 15-1410; Entergy Corporation v. EPA, et al., No. 15-1413; LG&E and KU Energy, LLC v. EPA, No. 15-1418; West Virginia Coal Association v. EPA, et al., No. 15-1422; Newmont Nevada Energy Investment, LLC, et al. v. EPA, et al., No. 15-1432; Kansas City Board of Public Utilities v. EPA, No. 15-1442; North American Coal Corporation, et al. v. EPA, et al., No. 15-1451; Indiana Utility Group v. EPA, et al., No. 15-1459; Louisiana Public Service

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/s/ Brian H. Lynk
BRIAN H. LYNK

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GLOSSARY

CAA	Clean Air Act
CCS	Carbon Capture and Storage (or Carbon Capture and Sequestration)
CO_2	Carbon Dioxide
CPP	Clean Power Plan
DOE	Department of Energy
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005
IEA	International Energy Agency
JA	Joint Appendix
Lb-CO_2	Pounds of carbon dioxide
MATS	Mercury and Air Toxics Standards
MW	Megawatt
MWh-g	Megawatt-hour on a gross output basis
RIA	Regulatory Impact Analysis
RTC	Response to Comments
TSD	Technical Support Document

INTRODUCTION

This case involves challenges to EPA's first-ever standards of performance for carbon dioxide ("CO_2") emissions from new, modified, and reconstructed fossil-fuel-fired power plants ("the Rule"). 80 Fed. Reg. 64,510 (Oct. 23, 2015). Fossil-fuel-fired power plants emit vast amounts of CO_2 pollution, which poses a monumental threat to Americans' health and welfare by driving long-lasting changes in our climate, leading to an array of severe negative effects that will worsen over time. In the challenged Rule, EPA has thoroughly and carefully applied—based on an extensive administrative record—the applicable statutory criteria in Section 111 of the Clean Air Act ("CAA" or "the Act"), 42 U.S.C. § 7411. The Rule identifies a set of "best" "adequately demonstrated" systems of emission reduction for new, reconstructed, and modified power plants and establishes standards of performance that reflect an achievable degree of CO_2 emission limitation applying those systems. Id. § 7411(a)(1); 80 Fed. Reg. at 64,512-13 (Table 1).

STATEMENT OF JURISDICTION

The consolidated petitions for review of the Rule and of EPA's decision denying reconsideration thereof were timely filed in this Court pursuant to 42 U.S.C. § 7607(b). Petitioner Energy & Environment Legal Institute lacks standing to raise the procedural claim that it alone pursues.

STATEMENT OF THE ISSUES

Section 111 of the Clean Air Act, 42 U.S.C. § 7411, directs EPA to set "standards of performance" for new sources within listed source categories. Those standards must reflect the degree of emission limitation achievable applying the "best system of emission reduction" EPA determines has been "adequately demonstrated," taking into account cost and other factors. Against this background, this case presents the following issues:

1. Did EPA reasonably determine that post-combustion partial carbon capture and storage ("CCS") is an adequately demonstrated system of CO_2 emission reduction for steam generating units where CCS is already in successful full-scale commercial operation at the Boundary Dam plant in Canada and where multiple steam units in the United States have successfully employed carbon capture technology?

2. Did EPA adequately consider the costs of CCS where EPA examined several economic metrics and found the Rule's costs to be reasonable both at an industry-wide level and at the level of an individual plant?

3. Did EPA reasonably determine that the Rule's respective standards for new, modified, and reconstructed steam generating units are achievable?

4. Did EPA appropriately decline to subcategorize and set a different standard for new steam units burning lignite coal where lignite-fueled units can meet the established standard at reasonable cost?

5. Did EPA reasonably explain why CCS is not an adequately demonstrated system of emission reduction for combustion turbines?

6. Did EPA appropriately elect to regulate CO_2 emissions from new power plants under Section 111 where power plants are the largest sources of CO_2 and where CO_2 and other greenhouse gas emissions pose monumental threats to public health and welfare by driving changes in climate?

7. Did EPA err by not docketing certain emails related to a different rulemaking and that EPA did not rely upon?

PERTINENT STATUTES AND REGULATIONS

The pertinent statutes and regulations are set forth in a separate addendum.

STATEMENT OF THE CASE

I. STATUTORY AND REGULATORY BACKGROUND.

A. The Clean Air Act.

The purpose of the CAA is to promote public health and welfare by reducing air pollution. 42 U.S.C. § 7401(b)(1). CAA Section 111, id. § 7411, constitutes the "Standards of Performance" program for new and existing stationary sources. Section 111(b) establishes a two-step process for regulating emissions from new sources. First, Section 111(b)(1)(A) requires that EPA identify and list source categories for potential regulation. Id. § 7411(b)(1)(A). EPA must list a source category "if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Id. EPA is thus required, at the time of listing, to make what is known as an endangerment finding: a determination that a source category is a proper candidate for regulation given its significant contributions to harmful air pollution.[1]

Second, after a source category is listed, EPA must prescribe federal "standards of performance for new sources within such category." Id. § 7411(b)(1)(B); see id. § 7411(a)(2) (defining "new source" to include modifications).

A "standard of performance" is defined 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). Under that definition, EPA identifies those "system[s] of emission reduction" that are "adequately demonstrated" for a particular source category; determines the "best" of those systems, based on the relevant criteria; and then derives from that system an "achievable" emission-performance level for sources. 80 Fed. Reg. at 64,538. In determining which systems of emission reduction are "adequately demonstrated," EPA must "tak[e] into account the cost of achieving such

[1] As in the Rule, EPA refers to this determination as a whole as the "endangerment finding," including both the "causes, or contributes" and "endanger public health or welfare" elements. See 80 Fed. Reg. at 64,529.

reduction and any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1). In determining the "best" of those systems, EPA may consider those same factors, along with the amount of emission reduction and fostering technological innovation. 80 Fed. Reg. at 64,538-40 (citing case law). A standard is "achievable" if a technology that will allow new sources to meet the standard can reasonably be projected to be available to them at the time they are constructed. Portland Cement Ass'n v. Ruckelshaus ("Portland Cement I"), 486 F.2d 375, 391-92 (D.C. Cir. 1973). Sources are typically free to meet a standard of performance by any means they choose, but a source must be able to "achiev[e]" the promulgated standard if it "appl[ies]" the "best system of emission reduction … adequately demonstrated" (hereinafter, "Best System"). See 42 U.S.C. § 7411(a)(1); 80 Fed. Reg. at 64,540-41 & n.151. The Best System determination, however, "looks toward what may fairly be projected for the regulated future, rather than the state of the art at present." Portland Cement I, 486 F.2d at 391.

B. The Energy Policy Act of 2005.

In 2005, Congress passed the Energy Policy Act ("EPAct"), Pub. L. No. 109-58, 119 Stat. 594 (2005), which included three programs to "accelerate[] market penetration for clean coal technologies," H.R. Rep. No. 109-215, at 169 (2005), JA4663. EPAct Sections 402(i) and 421(a) provide grants to projects related to advanced coal technologies, like CCS, see 42 U.S.C. §§ 15962(i), 13573(e) (as codified), while EPAct Section 1307(b) added Section 48A(g) of the Internal Revenue

Code to provide tax incentives for facilities employing advanced coal technology. 26 U.S.C. § 48A(g) (as codified).[2]

All three provisions include language directed at the EPA Administrator's consideration of whether and when technologies are "adequately demonstrated" for purposes of Section 111 (as well as for similar determinations under CAA Sections 169 and 171). Section 402(i) provides in pertinent part that:

> No technology … solely by reason of the use of the technology, … by 1 or more facilities receiving assistance under this Act, shall be considered to be … adequately demonstrated for purposes of section 7411 of this title[.]

Section 421(a) likewise provides that:

> No technology … shall be treated as adequately demonstrated for purpose of section 7411 of this title … solely by reason of the use of such technology, … by one or more facilities receiving assistance under section 13572(a)(1) of this title.

Section 48A(g) provides that:

> No use of technology … by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology … is … adequately demonstrated for purposes of section 111 of the Clean Air Act[.]

Because the EPAct only precludes "adequately demonstrated" determinations made "*solely* on the basis of federally-funded facilities," a

[2] Consistent with the Rule, this brief refers to the two grant provisions by their public law section numbers, Sections 402(i) and 421(a), but refers to the tax credit provision by its U.S. Code section number, Section 48A(g).

"technology might be adequately demonstrated if that determination is based at least in part on non-federally-funded facilities." Nebraska v. EPA, No. 4:14-CV-3006, 2014 WL 4983678, at *4 n.1 (D. Neb. Oct. 6, 2014) (emphasis in original) (interpreting Section 402(i)).

II. FACTUAL BACKGROUND.

A. Greenhouse Gas Emissions and Climate Change.

The concentration of CO_2 and other greenhouse gases in the atmosphere has risen to essentially unprecedented levels as a result of human activities, and these gases are the root cause of ongoing global climate change. 74 Fed. Reg. 66,496, 66,517 (Dec. 15, 2009). In Massachusetts v. EPA, 549 U.S. 497 (2007), the Supreme Court held that the "sweeping definition of 'air pollutant'" in the CAA unambiguously covers "greenhouse gases"—so named because they "act[] like the ceiling of a greenhouse, trapping solar energy and retarding the escape of reflected heat." Id. at 505, 528-29 (citing 42 U.S.C. § 7602(g)). In response, EPA comprehensively assessed the effects of greenhouse gas pollution, concluding that it endangers the public health and welfare of current and future generations. 74 Fed. Reg. at 66,516-36. EPA determined, among other things, that the risks include sea-level rise, extreme weather events, drought, and harm to agriculture and water resources; as well as sickness or mortality from reduced air quality, intensified heat waves, and increases in food- and water-borne pathogens. Id. at 66,497, 66,524-36.

Climate change is already occurring. Nineteen of the twenty warmest years on record occurred in the past twenty years; 2015 was the hottest year ever recorded and 2016 is on track to be even hotter.[3] Recent scientific assessments have found that climate change is damaging every area of the country. See 80 Fed. Reg. at 64,517-22. These assessments make clear that substantially reducing emissions now—and even more dramatically going forward—is necessary to avoid the worst impacts. Id. at 64,520.

B. Fossil-Fuel-Fired Power Plants.

Fossil-fuel-fired power plants, which include steam units (generally burning coal) and combustion turbines (generally burning gas), are particularly large sources of numerous air pollutants. Since the CAA's passage in 1970, EPA has set emission requirements for these plants to fulfill the Act's primary objective of protecting public health and the environment. In 1971, EPA listed steam units as a source category for regulation under Section 111, finding that the source category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A); 36 Fed. Reg. 5931 (Mar. 31, 1971). Combustion turbines were similarly listed in 1977. 42 Fed. Reg. 53,657 (Oct. 3, 1977).

[3] Nat'l Oceanic & Atmospheric Admin., Global Temperature Recap, available at https://www.climate.gov/news-features/videos/2014-global-temperature-recap, JA5108-10; https://www.climate.gov/news-features/featured-images/no-surprise-2015-sets-new-global-temperature-record, JA5215; Time, "2016 on Course to Be Hottest Year Ever Recorded," available at http://time.com/4569522/climate-change-hottest-year-ever-2016, JA5290-91.

Fossil-fuel-fired power plants are by far the highest-emitting stationary sources of CO_2, generating approximately 37 percent of all domestic man-made CO_2 emissions—almost three times as much as the next ten stationary-source categories combined. See 80 Fed. Reg. at 64,523. No serious effort to address the monumental problem of climate change can succeed without meaningfully limiting these plants' CO_2 emissions.

C. The Final Rule.

In 2012, EPA proposed a CO_2 performance standard for new fossil-fuel-fired power plants (but not one for modified or reconstructed units) based upon combustion of natural gas rather than coal.[4] 77 Fed. Reg. 22,392 (Apr. 13, 2012). EPA withdrew that proposal in part due to comments that there could be new coal-fired plants, including as a hedge against natural gas price increases. 79 Fed. Reg. 1352 (Jan. 8, 2014).

In 2014, EPA proposed a new set of CO_2 performance standards for new, modified, and reconstructed fossil-fuel-fired power plants, and proposed emission guidelines under Section 111(d) for existing plants. See 79 Fed. Reg. 1430 (Jan. 8, 2014) (new sources); 79 Fed. Reg. 34,830 (June 18, 2014) (existing sources); 79 Fed. Reg. 34,960 (June 18, 2014) (modified and reconstructed sources). EPA also issued a

[4] The statutory definition of a "new source," 42 U.S.C. § 7411(a)(2), includes modified and reconstructed sources as well as newly constructed sources. For ease of understanding, this brief uses the term "new source" to describe newly constructed sources, and separately addresses modified and reconstructed sources as appropriate.

Notice of Data Availability regarding the Agency's interpretation of the EPAct. 79 Fed. Reg. 10,750 (Feb. 26, 2014).

On October 23, 2015, EPA published two final rules. The first (the Rule) established CO_2 performance standards under Section 111(b) for new, modified, and reconstructed plants, and is the subject of these Petitions. 80 Fed. Reg. at 64,510. The other established Section 111(d) emission guidelines for states to follow in developing plans to limit CO_2 from existing plants, and is the subject of separate litigation.[5] 80 Fed. Reg. 64,662 (Oct. 23, 2015).

1. Performance standards for new steam units.

Under the Rule, the Best System for new steam units is a highly efficient supercritical pulverized coal boiler implementing partial post-combustion CCS. See 80 Fed. Reg. at 64,512-13. On the basis of this Best System, EPA established a performance standard for all new steam units of 1,400 pounds of CO_2 per megawatt-hour on a gross output basis ("lb-CO_2/MWh-g"). Id. EPA's 2014 proposal had identified a standard of 1,100 lb-CO_2/MWh-g, but EPA promulgated the less stringent 1,400-lb standard to ensure that the Best System could be implemented at reasonable cost. Id. at 64,513.

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[5] The rule for existing sources, known as the Clean Power Plan, is the subject of a separate set of consolidated petitions in this Court (Case No. 15-1363 and consolidated cases). The Court, sitting *en banc*, heard argument with respect to that rulemaking on September 27, 2016.

a. Supercritical pulverized coal boiler.

The Best System includes the use of a highly efficient supercritical pulverized coal boiler. Id. Pulverized coal boilers burn coal that has been crushed into a powder, increasing its surface area. Id. at 64,525. Supercritical boilers increase temperature and pressure so that steam in the unit is above the "critical" point of water. See id. at 64,594 n.507. Above water's critical point, steam behaves like both a liquid and a gas. This differs from "subcritical" boilers, which operate below water's critical point. Id. "Ultra-supercritical" boilers, a kind of highly efficient supercritical boiler, operate "well above the critical point" of water, allowing them to generate heat at even greater efficiency levels. Id. at 64,594 n.512.

b. Carbon capture and storage.

The Best System is also premised on the installation of a carbon capture and storage system. Id. at 64,549. CCS separates CO_2 from a steam unit's exhaust stream using chemical solvents; by heating the resulting mixture, the absorbed CO_2 can then be isolated and processed into a form that can be permanently stored underground. Id.

As noted above, the promulgated standard for new steam units is less stringent than what EPA proposed in 2014. A key difference is that, while the proposed standard was based on a new steam unit capturing roughly 40 percent of its CO_2 emissions, the final standard is based on a less demanding CO_2 capture rate. Id. at 64,548. Specifically, units burning higher quality bituminous coal can meet the standard by capturing approximately 16 percent of their CO_2 emissions, while units burning lower quality coals (subbituminous and lignite) can meet the standard with a capture rate of approximately 23 percent. See id. EPA rejected a standard based on "full CCS" (i.e., more than 90 percent CO_2 capture and storage), due to cost concerns. Id.

CO_2 storage may be available on-site, id., or the captured CO_2 may be transported by pipeline to a facility that complies with greenhouse gas reporting requirements under 40 C.F.R. pt. 98 subpt. RR. See id. at 64,581. EPA considered two kinds of feasible geologic storage: (1) injection into deep saline formations; and (2) injection into oil fields, where injected CO_2 increases oil-production efficiency through a process known as "enhanced oil recovery." See id. at 64,576, 64,578-79. Injection for both types of storage is regulated under the Safe Drinking Water Act's Underground Injection Control Program, which addresses deep saline formations as "Class VI" wells and oil recovery applications as "Class II" wells. Id. at 64,583-86.

EPA conservatively assessed the costs of the Best System by assuming only storage in deep saline formations, which is more expensive than implementing CCS by selling captured CO_2 for oil recovery. See id. at 64,563, 64,566. EPA determined that these costs were reasonable. Id. at 64,572. EPA also found that plants in most parts of the country would have access to CO_2 storage in deep saline formations, and that 29 states also have active oil recovery operations or geology amenable to such operations. See id. at 64,576.

c. Compliance alternatives.

As described above, EPA determined that new steam units can achieve the performance standard by installing "partial" (i.e., 16 to 23 percent CO_2 capture), rather than full, carbon capture systems. EPA further concluded that such units can meet the performance standard using alternative technologies. Id. at 64,545. In particular, EPA determined that units can "co-fire" a supercritical utility boiler with natural gas,[6] or build a new integrated gasification combined-cycle ("gasification") unit that employs very small amounts of either co-firing with natural gas or pre-combustion carbon capture (around 3 percent).[7] Id.

2. Performance standards for modified steam units.

The Rule establishes a performance standard for "large" steam unit modifications, which are defined as "any physical change in, or change in the method of operation of, a stationary source" "resulting in an increase in hourly CO_2 emissions … of more than 10 percent as compared to the source's highest hourly emission during the previous five years." Id. at 64,597. EPA set a unit-by-unit, rather than a uniform, modification standard: the standard for a particular modified unit is the unit's own best historical performance, as determined by its best annual average

[6] Natural gas co-firing is a cost-effective and widely available means of reducing CO_2 emissions by combusting natural gas along with coal in a steam unit boiler. See id. at 64,564.

[7] In a gasification unit, coal (or petroleum coke) is heated with water and oxygen, which react to form hydrogen and carbon monoxide (known as "syngas") that can be efficiently burned in a combined-cycle turbine. See id. at 64,552-53.

emission rate between 2002 and the present—except that no modified unit is required to meet a more stringent standard than those established for reconstructed units. Id. at 64,546, 64,658. EPA did not finalize a standard for modifications resulting in emission increases of 10 percent or less. Id. at 64,597.

3. Performance standards for reconstructed steam units.

The Rule establishes performance standards for "reconstructed" steam units where they meet two criteria: (1) the fixed capital cost of new components installed at the facility "exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," and (2) it is "technologically and economically feasible" to meet the standard of performance for reconstructed units. 40 C.F.R. § 60.15(b); 80 Fed. Reg. at 64,527. EPA determined that the Best System for reconstructed steam units was installation of the most efficient generation technology in use at a "well operated and maintained" unit. See 80 Fed. Reg. at 64,600. For large units (heat input rating above 2,000 MMBtu/h), this requires supercritical steam conditions, yielding a performance standard of 1,800 lb-CO_2/MWh-g; for small units (heat input rating at or below 2,000 MMBtu/h), it requires subcritical steam conditions, yielding a performance standard of 2,000 lb-CO_2/MWh-g. Id. EPA concluded that the Best System for reconstructed units does not include installation of CCS because existing units may have site-specific constraints that make CCS more difficult. See id. at 64,600, 64,557.

4. Performance standards for new and reconstructed combustion turbines.

EPA established three standards of performance for new and reconstructed combustion turbines: a standard of 1,000 lb-CO_2/MWh-g for natural gas-fired combustion turbines contributing significant amounts of power to the grid (the so-called "baseload" subcategory); a standard of 120 lb-CO_2/MMBtu for natural-gas fired combustion turbines with electric sales below the threshold for the "baseload" subcategory; and a standard of 120-160 lb-CO_2/MMBtu for "multi-fuel-fired units," which are units co-firing natural gas with other fuels like distillate oil. See id. at 64,513 & n.3, 64,601. For the "baseload" subcategory, EPA determined that the Best System was efficient natural gas combined-cycle technology (sometimes called "NGCC"). See id. at 64,615. EPA concluded that the Best System did not include CCS because CCS is not yet adequately demonstrated for some combustion turbines, like those that frequently or quickly cycle on and off or change load to accommodate fluctuations in electricity demand. See id. at 64,614. For the other two subcategories, EPA determined that the Best System was the use of "clean fuels" like natural gas or, for multi-fuel-fired units, fuels like propane or biodiesel. See id. at 64,601. EPA did not establish a performance standard for modified combustion turbines. See id. at 64,621-22.

D. Petitions for Reconsideration.

Following publication of the Rule, EPA received six petitions for reconsideration. EPA denied five petitions on May 6, 2016.[8] 81 Fed. Reg. 27,442; see also Basis for Denial of Petitions to Reconsider ("Reconsideration Memo"), EPA-HQ-OAR-2013-0495-11918, JA4405-48.

SUMMARY OF ARGUMENT

In the Rule, EPA established appropriate standards of performance for new, modified, and reconstructed fossil-fuel-fired power plants. Section 111 identifies the specific factors that EPA must consider in establishing such standards, and EPA properly applied those factors.

EPA reasonably exercised expert judgment in concluding that the best system of emission reduction for newly constructed steam generating units includes the use of a highly efficient boiler implementing partial CCS. The record amply supports EPA's conclusion that partial CCS is adequately demonstrated. Among other record support, the Boundary Dam plant in Saskatchewan, Canada, has already successfully implemented full (not just partial) CCS at commercial scale. EPA made it clear that its conclusions regarding CCS are amply supported and independent of EPA's consideration of facilities that received Federal support under the EPAct.

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[8] The remaining petition for reconsideration was filed by Biogenic CO_2 Coalition, whose petition challenging the Rule was severed and is being held in abeyance under Case No. 15-1480.

EPA also reasonably determined that a 1,400 lb-CO_2/MWh-g standard is achievable for new steam units throughout the United States and across a range of fuel types and conditions (including plants using lignite coal). Further, EPA permissibly determined that the costs of implementing partial CCS are reasonable. EPA considered costs carefully and conservatively, assessing costs at an industry-wide level and using two separate metrics to assess costs at the level of an individual plant.

Petitioners' assorted remaining attacks on EPA's legal interpretations, methodological approach, and judgments lack merit. EPA established appropriate modification and reconstruction standards for steam units. EPA reasonably explained why the Best System for new combustion turbines does not include CCS. EPA reasonably determined that CO_2 emissions from fossil-fuel-fired power plants were proper candidates for regulation as they pose threats to public health and welfare. And, on reconsideration, EPA properly declined to docket certain emails related to a different rulemaking that do not bear upon matters of central relevance.

STANDARD OF REVIEW

The Rule can be overturned only if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law" or in excess of EPA's "statutory jurisdiction, authority, or limitations." 42 U.S.C. § 7607(d)(9). "The scope of review under the 'arbitrary and capricious' standard is narrow and a court is not to substitute its judgment for that of the agency." Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983). The Court must "give an extreme degree of deference to the EPA's evaluation of scientific data within its technical expertise," especially where it reviews "EPA's administration of the complicated provisions of the [CAA]." Miss. Comm'n on Envtl. Quality v. EPA, 790 F.3d 138, 150 (D.C. Cir. 2015) (quotations omitted). Moreover, "[b]ecause [S]ection 111 does not set forth the weight that should be assigned to each of the[] factors" EPA considers in setting standards of performance, the Court grants EPA "a great degree of discretion in balancing them." Lignite Energy Council v. EPA, 198 F.3d 930, 933 (D.C. Cir. 1999). The Rule must be upheld if EPA "articulate[d] a satisfactory explanation for its action including a rational connection between the facts found and the choice made." Milk Indus. Found. v. Glickman, 132 F.3d 1467, 1476 (D.C. Cir. 1998) (quotation omitted); Small Refiner Lead Phase-Down Task Force v. EPA, 705 F.2d 506, 521 (D.C. Cir. 1983) (agency action must "conform to certain minimal standards of rationality" (quotation omitted)).

In interpreting statutory terms, the Court applies the familiar analysis of Chevron, U.S.A. v. Natural Res. Def. Council, Inc., 467 U.S. 837 (1984). The Court applies the language of the statute where it reflects "the unambiguously expressed intent of Congress," but where the statute is "silent or ambiguous with respect to the specific issue," the Court must defer to the agency's interpretation so long as it is "based on a permissible construction of the statute." Id. at 842-43; see also Long Island Care at Home, Ltd. v. Coke, 551 U.S. 158, 165 (2007).

ARGUMENT

I. EPA REASONABLY DETERMINED THE STANDARDS OF PERFORMANCE FOR REDUCING CO_2 EMISSIONS FROM NEW STEAM UNITS.

The statutory definition of "standard of performance" "provides that the emission limits that the EPA promulgates must be 'achievable' by application of a 'system of emission reduction' that the EPA determines to be the 'best' that is 'adequately demonstrated,' 'taking into account … cost … nonair quality health and environmental impact and energy requirements.'" 80 Fed. Reg. at 64,538 (quoting 42 U.S.C. § 7411(a)(1)). This Court has held that under any "sensible interpretation" of this language, EPA must also take into account "the amount of air pollution" reduced and the opportunity to encourage "technological innovation." Sierra Club v. Costle, 657 F.2d 298, 326, 346 (D.C. Cir. 1981).

EPA considered all of these required factors in developing the performance standard of 1,400 lb-CO_2/MWh-g for new steam units, exercising the "great degree of discretion" that Section 111 gives the Administrator in determining how to balance these factors in the context of a specific rulemaking. Lignite Energy Council, 198 F.3d at 933. Although Petitioners disagree with EPA's determination of the Best System for new steam units and its conclusion that such units can achieve the standard, EPA reasonably explained both the technical basis for these determinations and how the Rule is consistent with the EPAct and with this Court's long-established precedents interpreting Section 111(a)(1).

A. The Technologies and Methods Determined to Comprise the Best System for New Steam Units Are "Adequately Demonstrated."

In the Rule, EPA followed its established approach to determining the Best System, under which the Agency: first, "identifies the 'system[s] of emission reduction' that have been 'adequately demonstrated' for a particular source category"; second, "determines the 'best' of these systems after evaluating [the] extent of emission reductions, costs, any non-air health and environmental impacts, and energy requirements"; and third, "selects an achievable standard for emissions … based on the performance of the [Best System]." 80 Fed. Reg. at 64,538. EPA reasonably determined that partial carbon capture and storage is an adequately demonstrated system of emission reduction for new steam units, based on an extensive record of demonstrated projects in operation and under development, as well as vendor guarantees and academic literature. E.g., id. at 64,548-58.

1. EPA reasonably determined that the Best System for new steam units includes partial carbon capture and storage.

a. The record supports EPA's conclusion that partial carbon capture is adequately demonstrated for new steam units.

i. Boundary Dam.

EPA reasonably determined that the Best System for new steam units is a highly efficient supercritical pulverized coal boiler implementing partial CCS to the extent necessary to meet a final performance standard of 1,400 lb-CO_2/MWh-g. Id. at 64,545. The record amply supports EPA's determination that this degree of carbon capture is adequately demonstrated for new steam units. As EPA noted in its proposal, "[g]as absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO_2." 79 Fed. Reg. at 1479. Amine-based solvent systems "are in commercial use" and are "available for use in CCS systems at electric utilities." Literature Survey of Carbon Capture Technology, Technical Support Document ("Carbon Capture TSD"), 8, EPA-HQ-OAR-2013-0495-11773, JA3129.

Most significantly, post-combustion CCS is already in successful, full-scale commercial operation at the Boundary Dam plant in Saskatchewan, Canada. 80 Fed. Reg. at 64,549-50. The Boundary Dam project involved retrofitting an existing unit with a "full" carbon capture system designed to process the entire flue gas stream and capture more than 90 percent of the CO_2, id. at 64,548—a more complicated endeavor than installing partial CCS as part of new construction. Id. at 64,557. The carbon capture system at Boundary Dam began operation in October 2014, and its initial capture rates were roughly 75 percent of CO_2 emissions, considerably higher than the 16-23 percent CO_2 capture needed to meet the Rule's performance standard. Moreover, Boundary Dam's carbon capture performance has continued to improve in succeeding months, at times exceeding its design capacity. See Reconsideration Memo 8-9, JA4417-18. The captured CO_2 is more than 99.999 percent pure, a strong indication that the system is functioning well. 80 Fed. Reg. at 64,549.

Boundary Dam is under contract to sell a certain volume of its captured CO_2 for use in enhanced oil recovery, and any excess CO_2 is geologically sequestered in nearby deep brine-filled sandstone formations. Id. Because the system has recovered more CO_2 in some months than the oil recovery operator can accommodate, Boundary Dam is in fact sequestering excess CO_2. Response to Comments for New EGUs ("RTC") – Chapter 6, 6.3-85, EPA-HQ-OAR-2013-0495-11865, JA2553; see also Reconsideration Memo 10-11 & nn.28-30, JA4419-20; RTC 6.3-260, JA2669.[9]

Petitioners' attempts to distinguish Boundary Dam's performance are unavailing. They refer to the unit's 110 MW size as "smaller" than a "typical" plant, Non-State Br. 32, but half of all domestic commercial coal-fired power plants are 149 MW or smaller. Revised Regulatory Impact Analysis ("RIA"), 2-6 (Table 2-3), EPA-HQ-OAR-2013-0495-11877, JA2809. Most importantly, Boundary Dam utilizes *full* carbon capture, whereas the Best System contemplates only partial carbon capture at a rate of 16-23 percent. 80 Fed. Reg. at 64,549-50. As EPA explained, "the same carbon capture equipment" used to achieve full capture at Boundary Dam "could be used to treat approximately 50 percent of the flue gas from a 220 MW facility—or 20 percent of the flue gas from a 550 MW facility." Id. at 64,550. Thus, the carbon capture system at Boundary Dam could be used to treat part of the flue gas stream at

[9] Contrary to Petitioners' suggestion, see State Br. 10, the costs of the CCS system at Boundary Dam were on budget; cost overruns were associated with rebuilding the existing coal-fired boiler (which is not part of the Best System). 80 Fed. Reg. at 64,549 n.193; RTC 6.3-260, JA2669.

a much larger power plant and thereby capture a sufficient amount of CO_2 to achieve the standard. Indeed, CO_2 reductions at Boundary Dam for the 12-month period from February 2015 through January 2016 totaled 625,000 tons—far more than the 354,000 tons of CO_2 that a 500 MW power plant utilizing partial CCS would have to capture to meet the standard. Reconsideration Memo 9-10, JA4418-19.[10]

Petitioners also assert that Boundary Dam's operating experience is inapplicable because the project involves the use of captured carbon for enhanced oil recovery, while the Best System is based on geologic sequestration in deep saline formations. Non-State Br. 32. This purported distinction is inaccurate. As discussed above, Boundary Dam in fact is capturing more CO_2 than needed for oil recovery, and is geologically sequestering the excess.

Petitioners also make the misplaced assertion that Boundary Dam's actual performance is too unreliable to show that CCS is demonstrated. Non-State Br. 31-33. As the record shows, "the CO_2 capture system at [Boundary Dam] is operating successfully, the unit meets the Canadian performance standard for CO_2 emissions (which is more stringent than the U.S. standard), and it is producing more CO_2 for enhanced oil recovery than called for by contract." Reconsideration Memo 7, JA4416.

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[10] Inexplicably, Petitioners cite the fact that Boundary Dam burns lignite coal as an additional reason to disregard its performance, State Br. 32, even though a *lower* rate of carbon capture (16 percent) is necessary to meet EPA's standard at utilities burning bituminous coal rather than lignite or subbituminous (23 percent). 80 Fed. Reg. at 64,548.

Since September 2015, it has operated without any downtime other than routine scheduled maintenance, and its performance in recent months has even bettered the system's design capacity. Id. 9-10, JA4418-19. Furthermore, the early operating difficulties at Boundary Dam related chiefly to ancillary operating systems rather than directly to the carbon capture system, and stemmed in part from the complexity of retrofitting CCS onto an existing plant, which is not a concern for *new* steam units. See id. 8, 10 JA4417, 4419.[11]

Petitioners chide EPA for finding that Boundary Dam's performance is on an "upward trajectory," Non-State Br. 33, but fail to acknowledge what that upward trajectory entails—performance at levels exceeding design capacity, which easily meets EPA's standard as well as the more stringent Canadian standard. Reconsideration Memo 8-10, JA4417-19. EPA also found, with ample record support, that the plant's initial operational issues were successfully resolved. Id. 10, JA4419.[12]

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[11] Similarly, Petitioners cite EPA's statement in the Clean Power Plan that CCS is an emerging technology and not the Best System for *existing* sources. Non-State Br. 20-21. But Petitioners fail to mention the reason: retrofits of carbon capture technology at existing sources are more complicated and expensive and may not be feasible due to space limitations that are not present for new sources. See 80 Fed. Reg. at 64,883-84; Greenhouse Gas Mitigation Measures Technical Support Document (from Clean Power Plan docket) ("CPP Mitigation TSD"), 5-4, EPA-HQ-OAR-2013-0495-11879, JA3107; accord Reconsideration Memo 10 & n.25, JA4419. In addition, EPA noted in the Clean Power Plan that CCS can be a viable option for particular existing sources, and included a regulatory provision to accommodate those cases. See 80 Fed. Reg. at 64,884; 40 C.F.R. § 60.5860(f)(2).

[12] Petitioners' claim that EPA relied on "unverified" information concerning Boundary Dam's performance in denying reconsideration petitions, Non-State Br. 33,

(Footnote Continued …)

EPA's standard of performance already is structured, moreover, to accommodate the possibility that a carbon capture system may experience initial resolvable operating issues. Specifically, it is formulated as a 12-*operating*-month average, which accounts for both variable performance and maintenance downtime. 80 Fed. Reg. at 64,573; Achievability of the Standard for Newly Constructed Steam EGUs – Technical Support Document ("Achievability TSD"), 1-2, EPA-HQ-OAR-2013-0495-11771, JA2963-64.

Finally, the fact that Boundary Dam was partially subsidized by the Canadian government does not render it inappropriate to support the determination that the carbon capture technology it utilizes is adequately demonstrated. Non-State Br. 31. Nothing in the text of Section 111(a)(1) or this Court's jurisprudence suggests that such subsidies automatically disqualify a plant's operational experience from consideration in determining the Best System. And, as discussed further below (infra

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is also misplaced. EPA properly considered documented monitoring data reported by Boundary Dam. Reconsideration Memo 10, JA4419. Petitioners also improperly cite extra-record information from June 2016 purporting to show that Boundary Dam's performance is defective. Non-State Br. 32; see 42 U.S.C. § 7607(d)(7)(A). In fact, Boundary Dam's website indicates that in June 2016, its carbon capture system remained on track to meet the plant's 2016 annual goal, and that minor operational issues ancillary to the carbon capture system were successfully resolved. See http://www.saskpower.com/about-us/blog/bd3-status-update-june-2016/, JA5217-21. Equally improper is Intervenors' citation of a June 2016 newspaper article stating that Boundary Dam renegotiated its contract with the oil recovery operator to avoid paying a penalty. Int. Br. 12-13 & n.6. That article indicates that the renegotiation does not relate to current performance and confirms that Boundary Dam continues to capture more CO_2 than contractually required; thus, the oil recovery operator also renegotiated that portion of the contract.

Argument I.E), the costs of the identified Best System are reasonable, and EPA's analysis conservatively assumed no subsidies. E.g., 80 Fed. Reg. at 64,563.

ii. Additional non-EPAct sources.

EPA also considered other coal-fired plants employing post-combustion capture technology, including AES Warrior Run in Cumberland, Maryland; Shady Point in Panama, Oklahoma; and Searles Valley Minerals in Trona, California. Id. at 64,550-51. Each of these plants has been operating for multiple years and employs the same carbon capture method on which EPA's Best System determination is based—post-combustion amine scrubbing. Id. None received assistance through the EPAct or its associated tax credits; thus, EPA's consideration of these plants was not subject to EPAct-related limitations. Id. These plants provide additional evidence that post-combustion carbon capture is adequately demonstrated. Id.

These three plants capture slightly smaller amounts of CO_2 than the standard contemplates—up to nearly 80 percent of what a 500 MW plant meeting the standard by using partial CCS would capture. Id. at 64,574 (Table 12). Petitioners are incorrect, however, to suggest that EPA "presented no evidence" that these projects "could be scaled up to commercial-scale units while being reasonably reliable, efficient, and not unreasonably costly." Non-State Br. 34. On the contrary, the record is replete with information explaining how small- or pilot-scale carbon capture systems could be successfully scaled up. 80 Fed. Reg. at 64,550, 64,557; RTC 6.3-23, 6.3-44, JA___, JA___. Notably, much of this detailed how-to comes from studies by steam electric utilities. 80 Fed. Reg. at 64,557 (discussing studies by American Electric Power and Tenaska Trailblazer Partners); see also RTC – Chapter 2, 2.1-37, EPA-HQ-OAR-2013-0495-11861, JA___.

Additionally, EPA explained that most of the complexities or "operating issues" identified by commenters as potentially complicating utility-scale implementation of CCS are associated with full, not partial carbon capture, or with retrofitting existing plants to add such technology. 80 Fed. Reg. at 64,557. Because developers of newly constructed plants can more easily anticipate and resolve engineering challenges such as space limitations or steam requirements for solvent regeneration (part of the capture process), such challenges are more readily surmountable when implementing partial CCS at utility-scale. Id. Thus, EPA reasonably considered the successful operation of all of the above-listed plants employing post-combustion capture technology, regardless of whether they are operating at utility-scale. Indeed, as EPA explained, this Court has long held that under Section 111, "data from pilot-scale, or less than full-scale operation, can be shown to reasonably demonstrate performance at full-scale operation" if EPA "explain[s] the necessary steps involved in scaling up [the] technology and how any obstacles may reasonably be surmounted when doing so." Id. at 64,557 & n.243 (citing cases); see Sierra Club, 657 F.2d at 363-64 (upholding standard that no plant was then meeting either at pilot- *or* commercial-scale, based on projected improvement in scrubber technology[13]), 380-84 (endorsing EPA's use of operational data from small-scale plants to project utility-scale performance of baghouse technology); Essex Chemical Corp. v. Ruckelshaus, 486 F.2d 427, 440 (D.C. Cir. 1973) (concluding that EPA reasonably considered "prototype testing data" and vendor guarantees to determine that system was adequately demonstrated).

Furthermore, while these three plants are not sequestering the CO_2 they capture—AES Warrior Run and Shady Point both sell their captured CO_2 for use in food or beverage processing, while Searles Valley Minerals uses it for carbonation of brine in the process of producing soda ash, 80 Fed. Reg. at 64,550—their long and successful operation of post-combustion carbon capture technology supports EPA's analysis. Once captured, CO_2 is amenable to geologic storage and to transportation by pipeline regardless of its source. That is, it is the same, fungible molecule whether it comes from a utility boiler, an industrial boiler, a gasification operation, an industrial process, or some other source. And, as discussed further below, EPA also considered the integration of CO_2 capture with geologic sequestration and reasonably concluded that the system as a whole was adequately demonstrated. Infra Section I.A.2.

EPA's determination is also supported by vendor guarantees, 80 Fed. Reg. at 64,554-55, academic and other literature, id. at 64,555, and industry statements, id. at

[13] Unlike Sierra Club, where no existing plant had achieved the standard at issue, here (as detailed above), Boundary Dam already is capturing carbon at rates and volumes that exceed what would be necessary for a utility boiler utilizing partial capture to meet EPA's standard, and is sequestering the excess carbon.

64,555-56, as well as by longstanding industry experience with CO_2 sequestration, id. at 64,578-81. See Portland Cement I, 486 F.2d at 401-02 (accepting vendor guarantees and expert testimony as justification for adequate demonstration and achievability of Section 111 standards); Sierra Club, 657 F.2d at 364 (same); Nat'l Petrochem. & Refiners Ass'n v. EPA, 287 F.3d 1130, 1137 (D.C. Cir. 2002) (same).

iii. Corroborative sources.

EPA further noted that several facilities receiving grant assistance (but not tax credits) under the EPAct further corroborate that post-combustion CCS is feasible and demonstrated. 80 Fed. Reg. at 64,551-553 (describing Petra Nova WA Parish project, a 610 MW plant implementing partial CCS, slated to commence operations in 2017; American Electric Power/Alstom Mountaineer (a 20 MW slipstream); and Southern Company Plant Barry (a 25 MW slipstream)). But EPA also made clear that its determination that post-combination carbon capture was demonstrated and feasible is fully supportable without this additional corroboration. Id. at 64,551.

b. EPA reasonably determined that carbon storage is adequately demonstrated.

Petitioners further contend that CCS is not "adequately demonstrated" on grounds that CO_2 storage capacity is not available throughout the country. See State Br. 27-29; Non-State Br. 27-30; North Dakota Br. 12-13. This argument lacks merit for a host of reasons.

EPA specified that captured CO_2 must be transferred to a facility reporting under 40 C.F.R. pt. 98 subpt. RR, and identified several ways that the captured CO_2 may be successfully stored. The captured CO_2 can be stored either: (a) in a deep saline formation or other geologic formation, pursuant to the rules for Class VI wells under EPA's Underground Injection Control Program; or (b) in oil reservoirs via injection wells used for enhanced oil recovery, pursuant to the rules for Class II wells under the Underground Injection Control Program). See 80 Fed. Reg. at 64,583-88. The Rule also provides for a case-by-case demonstration of alternative methods for storing captured CO_2 that are equally as secure. Id. at 64,581.

EPA also identified achievable compliance alternatives available to new steam units that do not involve *any* CO_2 capture or storage at all and do not face geographic constraints. Specifically, new steam units can co-fire with some amount of natural gas to meet the standard of performance, or a new source can use coal gasification technology with a small amount of natural gas co-firing. Id. at 64,513; see also id. at 64,564-65 (explaining that co-firing can be implemented at less cost than partial CCS and does not pose adverse non-air quality health, environmental or energy impacts); Reconsideration Memo 33-34 (noting that co-firing, even at high rates, is well demonstrated), JA___.

The record supports EPA's conclusion that there is ample storage capacity for new sources electing to meet the standard of performance by capturing CO_2 and storing it. First, new sources choose where to locate, and so can site proximate to available storage sites. Petitioners maintain that some states (11 out of the 50) lack CO_2 storage capacity within their borders, and assert (incorrectly) that EPA failed to examine the volume and suitability of the capacity that does exist. Non-State Br. 27-28. They further assert that the availability of enhanced oil recovery sites is geographically constrained. Id. 29-30. However, Petitioners greatly exaggerate the degree of difficulty in finding CO_2 storage capacity. Even without considering enhanced oil recovery, the United States has 2.2 to 3.3 trillion metric tons of subsurface CO_2 storage capacity according to Department of Energy ("DOE") and United States Geological Survey estimates. 80 Fed. Reg. at 64,578-79; RIA 2-35, JA2838; see also Geographic Availability Technical Support Document ("Geographic Availability TSD"), 5, EPA-HQ-OAR-2013-0495-11772, JA2973. This estimated storage capacity exceeds the *total* annual CO_2 emissions from the domestic energy sector by a factor of at least 500.[14]

Contrary to Petitioners' claim, EPA examined the volume and suitability of geologic storage capacity in each state as well as nationwide. See, e.g., Geographic Availability TSD 6-7, JA2974-75 (tabulating state-by-state CO_2 storage resources). EPA found that "there are 39 states for which onshore and offshore deep saline formation storage capacity has been *identified*," but that does not necessarily mean that

[14] See U.S. Geological Survey, Nat'l Assessment of Geologic Carbon Dioxide Storage Resources—Results, Circular 1386, Version 1.1 (Sept. 2013) 15, EPA-HQ-OAR-2013-0495-11561, JA3818 (cited in 80 Fed. Reg. at 64,579 n.380; RIA 2-35 n.16, JA2838).

all eleven of the remaining states *lack* such capacity. 80 Fed. Reg. at 64,576 (emphasis added). Rather, as EPA explained, it relied on "a conservative outlook of potential areas available for the development of CO_2 storage in that we include only areas that have been assessed to date." Id. at 64,583. Deep saline formation potential has not yet been assessed in most of the remaining states. See id. at 64,583 & n.413; RIA 2-33–2-34, JA2836-37.

Furthermore, EPA's assessment of potential storage sites did not consider only the availability of deep saline formations. Non-State Br. 27-28; State Br. 28. As noted above, enhanced oil recovery sites provide additional CO_2 storage capacity, which is a permissible means of storing captured CO_2 under the Rule. See 80 Fed. Reg. at 64,579-81, 64,588-89.[15] Oil recovery operations are currently being conducted in 12 states, and 17 additional states have oil reservoirs amenable to such operations. 80 Fed. Reg. at 64,576, 64,580. DOE analyses indicate that expanding oil recovery into these additional reservoirs over the next 20 years could store 18 billion metric tons of anthropogenic CO_2. Id. at 64,580 & n.391. DOE also has identified over 54 billion

[15] Petitioners contend that EPA should not have considered the extensive available information concerning industry's successful use of CO_2 injection for oil recovery because selling captured CO_2 to an oil recovery operator "can improve a project's economics" as compared with "pay[ing] to dispose of CO_2 in a deep saline formation." Non-State Br. 30. But oil recovery is a secure way to store captured CO_2 and is allowed under the Rule. 80 Fed. Reg. at 64,588. In any case, EPA fully addressed Petitioners' concern by conservatively excluding from its cost analysis any potential revenues from oil recovery or other "cost reduction opportunities." Id. at 64,564; see infra Argument I.E.1.

metric tons of potential CO_2 storage capacity in unmineable coal seams across 21 states. Id. at 64,576.

Moreover, while there are certain areas in which none of these types of suitable storage opportunities have been identified, a new coal-fired unit need not be located directly in such areas within a state. Rather, the new unit may be located proximate to a suitable geologic sequestration site, and then transmit its coal-generated electricity via the extensive electrical transmission system to the demand location. 80 Fed. Reg. at 64,582-83; see generally Geographic Availability TSD 1, 14-17, JA2969, JA2982-85. Alternatively, a new coal-fired plant may arrange to transport captured CO_2 by pipeline to a distant storage site that may be located in a different state from where the plant is located. 80 Fed. Reg. at 64,581 ("If an area does not have a suitable [sequestration] site, [steam units] can either transport CO_2 to [storage] sites via CO_2 pipelines" or "locate their units closer to [storage] sites and provide electric power to customers through transmission lines"). CO_2 has been transported via pipelines in the United States for nearly 40 years, and the pipeline network operates under a well-developed regulatory regime. Id. at 64,581-82.[16] While ten states currently have

[16] EPA did not "assum[e] *maximum* CO_2 pipeline length of 62 miles for new unit[s]," Non-State Br. 29 (emphasis added), and such an assumption would have been counterfactual, as the longest currently operating CO_2 pipeline extends more than 500 miles, eight times the "maximum" length Petitioners assert. 80 Fed. Reg. at 64,572; Office of Fossil Energy, National Energy Laboratory, A Review of the CO_2 Pipeline Infrastructure in the U.S. ("Infrastructure Study"), 6, EPA-HQ-OAR-2013-0495-11531, JA3741. Rather, the Infrastructure Study used a hypothetical 100-kilometer

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operating CO_2 pipelines, see Non-State Br. 29, the pipeline network has expanded significantly to meet growing demands for the use of CO_2 in oil recovery (nearly doubling in length over the past decade), and there are additional states with probable, planned or under-study pipeline projects. 80 Fed. Reg. at 64,576-77, 64,581-82. Thus, the availability of transmission and pipeline infrastructure supports EPA's conclusion that geologic sequestration sites need not be present in *every* geographic area of the country in order for CCS to be adequately demonstrated.

EPA reasonably concluded that very few parts of the country lack *all* of the following: (1) existing CO_2 pipelines; (2) probable, planned, or under study CO_2 pipelines; (3) active enhanced oil recovery operations; (4) oil and natural gas reservoirs (i.e., areas with potential for enhanced oil recovery); (5) deep saline formations; (6) unmineable coal seams; and (7) areas within 100 kilometers from a potential storage site. Id. at 64,583; see Geographic Availability TSD 2 (Fig. 1), JA2970. And, as shown above, for such a new source to genuinely be constrained by "geography," it would *also* have to be located in an area lacking the transmission infrastructure that would enable the plant to serve distant demand. In short, Petitioners' focus on the areas lacking identified CO_2 storage capacity dramatically overstates any asserted

distance between a CO_2 emission source and a storage site for purposes of its cost analysis. EPA did the same, in part because, "of the 500 largest existing CO_2 point sources, 95 percent are located within 100 kilometers … of a potential geologic storage reservoir. Therefore, it is reasonable to assume that a new source can be similarly located." RIA 5-17 n.21, JA2917.

"geographic constraint" on the siting of new coal-fired power plants. Petitioners also overlook that new coal-fired units "are unlikely to be built" in many of those areas, whether due to the stringency of applicable state emission standards, the lack of locally available coal to supply fuel for such plants, or other reasons. 80 Fed. Reg. at 64,576 & n.377; see also RIA 2-37–2-39, JA2840-42.

Although EPA must consider "the range of relevant variables that may affect emissions in different plants" when it evaluates a system of emission reduction under CAA Section 111, Nat'l Lime Ass'n v. EPA, 627 F.2d 416, 433 (D.C. Cir. 1980), the Agency may reasonably focus on *plausible* new sources or compliance scenarios, as it did here, rather than on unlikely hypotheticals. For example, in Portland Cement Ass'n v. EPA ("Portland Cement III"), 665 F.3d 177, 190 (D.C. Cir. 2011), this Court upheld Section 111 standards for cement kilns despite arguments that EPA "failed to consider the effects of its standards on older kilns." The Court deferred to EPA's record-based finding that it was "entirely conjectural" and unlikely that any new sources would use the older kiln design. Id. The Court has also recognized in other, comparable contexts that, even if a particular source might have difficulty meeting a technology-based standard due to its idiosyncratic design or location, such idiosyncrasies need not become the basis on which EPA sets the national standard. See, e.g., Kennecott Greens Creek Mining Co. v. MSHA, 476 F.3d 946, 957 (D.C. Cir. 2007) ("[T]hat a few isolated operations within an industry will not be able to comply

… does not undermine a showing that the standard is generally feasible.") (quotation omitted).

The cases Petitioners cite are not to the contrary. See Non-State Br. 27; State Br. 28. The cited portion of Sierra Club considered a question that is not relevant here—whether the phrase "best technological system," which was added to Section 111(a)(1) in the 1977 CAA amendments and then repealed in 1990, restricted EPA's ability to consider long-term cost, energy, and environmental impacts on a national scale and required a more narrow focus on the "maximum technologically feasible level of control." 657 F.2d at 329-30. In National Lime, the Court found that EPA "undertook no analysis" of a key variable affecting the achievability of the standard over broad regions. 627 F.2d at 441. Here, in contrast, EPA extensively surveyed the regional capacity for new sources to store captured CO_2 and the availability of alternatives where such storage capacity is limited. EPA also carefully examined the issue of water availability and water use impacts, see Non-State Br. 27, and showed why water usage for partial carbon capture would have minimal impacts. 80 Fed. Reg. at 64,592-93.

The availability of the non-CCS compliance alternatives discussed above also supported EPA's reasonable conclusion that the final standard of performance imposes no geographical constraints on the siting of potential new sources. See RTC 6.3-81, JA2550. Indeed, there is no obligation that each new source actually install the type of technology on which the standard is predicated. EPA can only mandate use of a particular means of compliance by meeting the criteria of 42 U.S.C. § 7411(b)(5), and EPA did not do so here. See 80 Fed. Reg. at 64,565 n.293. Thus, sources may meet an emissions limit of 1,400 lb-CO_2/MWh-g, by any means the source elects. 40 C.F.R. pt. 60 subpt. TTTT (Table 1) (set forth in 80 Fed. Reg. at 64,658). As this Court has long emphasized in construing Section 111(a)(1), "[i]t is the system which must be adequately demonstrated and the standard which must be achievable." Essex, 486 F.2d at 433; see Portland Cement III, 665 F.3d at 190 (rejecting contention that EPA had "failed to 'consider … the range of relevant variables that may affect emissions'" from sources using an older cement kiln design, because such sources could use alternative compliance methods); accord Natural Res. Def. Council v. EPA ("NRDC I"), 489 F.3d 1364, 1376 (D.C. Cir. 2007) (holding that EPA was not required to create a subcategory for a plant that could not comply using the technology on which standard was predicated, because the plant could "utilize other compliance techniques").

In addition to their mistaken claims regarding lack of storage capacity, Petitioners offer a cursory suggestion that long term storage in deep saline formations is not demonstrated. Non-State Br. 30. This is incorrect. It is demonstrated at Boundary Dam. See, e.g., 80 Fed. Reg. at 64,549. EPA has also issued permits for deep saline injection for two large-scale operations. Id. at 64,585. In issuing those permits, EPA found that regional and local features allowed the pertinent sites "to receive injected CO_2 in specified amounts without buildup of pressure which would create faults or fractures, and further, that monitoring provides early warning of any changes to groundwater or CO_2 leakage." Id. Although these operations have not yet commenced (and one has been cancelled), "[t]he permitting of these projects illustrates that permit applicants were able to address perceived challenges to the issuance of Class VI permits." Id. EPA also documented that decades-long monitoring at sequestration and oil recovery sites has shown no re-release of stored CO_2. Carbon Capture TSD 24, 26, 29-30, JA3145, JA3147, JA3150-51.

Petitioners' attempts to marginalize two large-scale CO_2 storage projects outside the United States that EPA considered are also unavailing. Non-State Br. 30; see 80 Fed. Reg. at 64,588-89. These projects are not subject to the Class VI regulatory requirements that assure secure storage at domestic sites, and in any case the purportedly "serious setbacks" at these projects, Non-State Br. 30, were minor, as "there were no [CO_2] releases to air," the projects' monitoring systems were effective, and all operational issues were addressed. 80 Fed. Reg. at 64,589.[17]

Finally, Petitioners devote one sentence of a brief to the cost of geologic sequestration, citing two sources for the proposition that site evaluations can take ten or more years and cost several hundred million dollars. Non-State Br. 28. These

[17] Petitioners also note that these projects are not "integrated with carbon capture at steam units," but this does not make them less pertinent in evaluating whether CO_2 storage is reasonably part of the Best System. Non-State Br. 30; see infra Argument I.A.2.

sources (the 2013 Global CCS Report[18] and 2013 IEA Roadmap[19]) both made broad, world-wide assessments. EPA reasonably relied on much more particularized cost estimates for domestic sources, accounting for the Class VI regulatory regime, and basing cost estimates on representative Midwest, Texas, North Dakota, and Montana locales. DOE, Cost and Performance Baseline for Fossil Energy Plant Vol. 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3 ("DOE Cost and Performance Baseline") 45-46, EPA-HA-OAR-2013-0495-11636, JA3536-37. In addition, Petitioners' sources assume that no preliminary screening of sites has occurred, but preliminary analyses of availability and potential storage capacity have been conducted, as illustrated in the Geographic Availability TSD cited above. Notably, the Global CCS Institute concluded that "CCS is often mistakenly perceived as an unproven or experimental technology. In reality, the technology is generally well understood and has been used for decades at a large scale in certain applications." 2013 Global CCS Report 10, JA1733.

In short, there is no new source that would be restricted from achieving the standard of performance due to lack of access to sequestration capacity, both because there is adequate capacity and because alternative means of compliance are readily

[18] Global CCS Institute, The Global Status of CCS 2013 ("2013 Global CCS Report"), EPA-HQ-OAR-2013-0495-9666, JA1722-1925.

[19] International Energy Agency, Technology Roadmap Carbon Capture and Storage ("2013 IEA Roadmap"), EPA-HQ-OAR-2013-0495-9666, JA1926-88.

available. CO_2 can be stored securely and at reasonable cost. Accordingly, it was reasonable for EPA to conclude that partial CCS is adequately demonstrated.

2. The record supports EPA's Best System determination both as to its individual system components and as to the selected Best System as a whole.

Petitioners contend that EPA's approach was legally flawed because EPA purportedly focused only on each individual "component" of the Best System and not on the system "as a whole." State Br. 18-19; Non-State Br. 21-26. The premise of this challenge is wrong from the outset, as Boundary Dam plainly *is* applying "the components of [the selected] best system together." Non-State Br. 22. Specifically, Boundary Dam operates (1) a pulverized coal boiler,[20] from which (2) CO_2 is captured using an amine-based solvent in a post-combustion process, and then (3) transported by pipeline, with some of it used in enhanced oil recovery operation and the rest (4) sequestered in deep saline formations. E.g., 80 Fed. Reg. at 64,549; compare Non-State Br. 21-22 (acknowledging the elements comprising the Best System). As shown above, Boundary Dam is operating successfully, supra Argument I.A.1.a.i, including all of its 125 integrated subsystems. See Non-State Br. 25. Likewise, all components of the pre-combustion carbon capture alternative system have operated for over 15

[20] As EPA explained, "[t]he experience at Boundary Dam is directly transferable to other types of post-combustion sources, including those using different boiler types"—such as a highly efficient supercritical boiler, rather than the rebuilt subcritical boiler at Boundary Dam—"and those burning different coal types" than the lignite used at Boundary Dam. 80 Fed. Reg. at 64,550.

years in fully-integrated fashion at the Dakota Gasification facility. 80 Fed. Reg. at 64,553. Thus, if Section 111 mandated that there be a "fully-integrated" example of the Best System in current commercial-scale operation before a system of emission reduction could be considered "adequately demonstrated" for new sources, that standard is met.

In any event, that is not the legal standard this Court has articulated. Instead, since the inception of the Section 111 program, the Court has recognized that "[i]t would have been entirely appropriate if [EPA] had justified [its] standards, not on the basis of tests on existing sources or old test data in the literature, but on extrapolations from this data, on a reasoned basis responsive to comments, and on testimony from experts and vendors." Portland Cement I, 486 F.2d at 401-02; 80 Fed. Reg. at 64,556. For example, in Sierra Club the Court upheld as reasonable EPA's determination that data concerning the performance of baghouse technology at small-scale plants—the only plants where it then had been installed—were representative of how the technology would perform in larger plants where many more baghouse modules would be required. 657 F.2d at 381-82. Although the largest baghouse system in operation at the time had "experienced some operation difficulties such as bag failure and high pressure drops," the Court accepted EPA's explanation that the failures were temporary and involved surmountable problems. Id. at 382. Thus, the lack of any baghouse system operating successfully at the scale anticipated by EPA's standard did not preclude a finding that the system was adequately demonstrated within the meaning of Section 111(a)(1). Id.

In comparable contexts, courts similarly have held that EPA can infer that a technology is demonstrated as a whole based on operation of component parts which have not, as yet, been fully integrated. 80 Fed. Reg. at 64,536; see Sur Contra La Contaminacion v. EPA, 202 F.3d 443, 447 (1st Cir. 2000) (upholding "best available control technology"[21] determination under the CAA based on a "novel combination of three proven control technologies" that "ha[d] not been used before"); Native Vill. of Point Hope v. Salazar, 680 F.3d 1123, 1133 (9th Cir. 2012) (deferring to Bureau of Ocean Energy Management's determination that a proposed well-capping technology was technically feasible, where "most major components for [the] system [were] available and ha[d] been [individually] field tested" (quotation omitted)).

Petitioners' cited cases do not hold otherwise. See State Br. 19. In Lignite Energy Council, this Court held it was reasonable for EPA to extrapolate from a technology's performance at utility boilers in order to determine if it was adequately demonstrated for use in industrial boilers. 198 F.3d at 933-34. There, *none* of the

[21] Best available control technology is defined as "an emission limitation based on the maximum degree of reduction of each pollutant … which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques." 42 U.S.C. § 7479(3); see also infra Argument I.D (addressing Petitioners' assertion that this Rule is inconsistent with an EPA staff letter discussing best available control technology).

components of the selected best system had been operated at industrial boilers, let alone operated "together" as a "fully-integrated" system. And in Portland Cement I, as noted above, the Court held that extrapolation from test data and testimony from experts and vendors was enough to support adequate demonstration. 486 F.2d at 401-02.

Importantly, CCS is more mature in its technological development than were "wet scrubbers" in 1971, a technology underlying the new source performance standards for this industry upheld in Essex. See 486 F.2d at 440; 37 Fed. Reg. 5768 (Mar. 21, 1972). The early wet scrubbing systems had little operating experience on power plants, and suffered from reliability issues. History of Flue Gas Desulfurization – Technical Support Document 3, 5, EPA-HQ-OAR-2013-0495-11774, JA3113, JA3115. Here, there are already fully-integrated, commercial-scale plants successfully employing both post-combustion CCS (Boundary Dam) and the pre-combustion alternative (Dakota Gasification), and amine-based carbon capture systems are in wide application throughout many industries.[22] 80 Fed. Reg. at 64,575. Likewise, the evidence here is more "than was available for the baghouse

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[22] Petitioners confusingly describe the Rule as assuming that "because a person can touch her toes, stand on one foot, drink a glass of water, and spin in a circle, she necessarily is able to do all these things *simultaneously*." Non-State Br. 23. That analogy bears no resemblance to what EPA did here. What EPA concluded is that a new utility can operate each component of the Best System—combust coal in a highly efficient new supercritical boiler, capture a portion of the resulting CO_2, transport it via pipeline, and sequester it—*in sequence*. Boundary Dam is doing so.

[performance standards] upheld as adequately demonstrated in Sierra Club." RTC 2.1-166, JA2103.

To the extent that some entities—commenting *before* Boundary Dam became operational—previously identified integration of this system's component technologies as a potential technical challenge, see Non-State Br. 24, the subsequent successful operation of Boundary Dam supports EPA's conclusion that any integration issues can be resolved. See Reconsideration Memo 10, JA4419.

Finally, Petitioners' partial quotation of five-year-old EPA guidance addressing limitations on greenhouse gases in certain CAA permitting programs fails to put that guidance in context. Non-State Br. 23-24.[23] First, this guidance predated the commencement of successful CCS operations at Boundary Dam. Second, it addressed the challenges of implementing full, not partial, CCS. Third, it discussed in very general terms how full CCS might be considered in the "best available control technology" analysis required for individual permits under the Act's Prevention of Significant Deterioration Program, but did not address coal-fired power plants specifically (let alone new steam units), nor did it contain any information regarding CCS cost, operating mechanics, or its history of use within any industry. See RTC 6.3-40, JA2524. As the Agency explained here, EPA "does not believe that this

[23] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (Mar. 2011), EPA-457/B-11-001, JA4741-4836, available at https://www.epa.gov/nsr/clean-air-act-permitting-greenhouse-gases.

general guidance, issued years before the present proceeding, addressed to multiple industries and not specific to coal-fired steam … units, is binding in any way, or is especially probative of whether partial CCS is [the Best System] for coal-fired [units]." Id.

3. EPA did not base its finding that partial CCS is "adequately demonstrated" solely on technical feasibility, and reasonably determined that partial CCS is available to new steam units.

Petitioners also contend that EPA was required to demonstrate that partial CCS is "commercially availab[le]," under this Court's opinion in Portland Cement I, 486 F.2d at 391 (as elaborated in Sierra Club and subsequent decisions). State Br. 13-16; Non-State Br. 17-18. They then claim that EPA violated this purported requirement by focusing singularly on "technical feasibility." State Br. 16-18. These arguments misstate both the case law and EPA's record explanation.

To begin with, Section 111 does not require EPA to find that a system of emission reduction is "commercially available" in order for it to be "adequately demonstrated." See 80 Fed. Reg. at 64,556. Portland Cement I, in fact, *rejected* the notion that "adequately demonstrated" necessarily implies "that any … plant now in existence be able to meet the proposed standards," since Section 111 "looks toward what may fairly be projected for the regulated future, rather than the state of the art at present." 486 F.2d at 391 n.59 (quotation omitted); see also id. (finding no requirement that the best system "must be in actual routine use somewhere" (quoting

S. Rep. No. 91-1196 (1970), JA4564)); 79 Fed. Reg. at 1466-67 (discussing additional legislative history).

Nor have subsequent cases reflected adoption of a "commercial availability" criterion. As discussed above, the Court has frequently upheld Agency findings that systems of emission reduction were "adequately demonstrated" where the technology at issue was not yet well-established commercially in the industry subject to the rule. See, e.g., Essex, 486 F.2d at 435; Sierra Club, 657 F.2d at 381-32; Lignite Energy Council, 198 F.3d at 933-34.

While the Sierra Club opinion recognized an "inherent tension" between the concepts of "emerging technology" and "adequately demonstrated technology," 657 F.2d at 341 n.157, it did not draw a bright-line distinction between the two as Petitioners suggest. State Br. 14-15. Rather, the Court emphasized that, where only pilot-scale data is available due to the relative novelty of a technology, it is incumbent on EPA to explain how the record as a whole "justif[ies] extrapolating from the pilot scale data to the conclusion that [the technology] is adequately demonstrated for full scale plants throughout the industry." Sierra Club, 657 F.2d at 341 n.157; accord State Br. 15 n.2 (acknowledging that the Court has upheld reliance on pilot-scale data where EPA explains how it is "representative of full-scale performance"). EPA has done so here when discussing such data. Nowhere did the Sierra Club Court identify or attempt to define "commercial availability" as a requirement under Section 111(a)(1), and other parts of the opinion (discussed at length above) make clear that systems of emission reduction need not be in widespread commercial use to be considered adequately demonstrated.[24]

Contrary to Petitioners' characterization, State Br. 13, EPA did not conclude that it need only show the selected system was "technically feasible." As EPA explained, "[a]n 'adequately demonstrated' system, according to [this Court], is 'one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'" 80 Fed. Reg. at 64,538 (quoting Essex, 486 F.2d at 433). EPA explained how partial CCS meets those criteria. Id. at 64,548.

In addition, the record indicates that CCS is, in fact, "commercially available." Id. at 64,556 & n.240 (noting that both pre- and post-combustion carbon capture systems "have commercial operating experience with demonstrated ability for high reliability"); DOE Cost and Performance Baseline 36, JA3527 (same). Thus, EPA's

[24] Petitioners cite out of context a statement by EPA counsel at oral argument in West Virginia v. EPA, No. 15-1363 (D.C. Cir. argued Sept. 27, 2016). Non-State Br. 18. That case involves challenges to EPA's legal authority related to standards for existing sources that are not present here. Counsel was responding specifically to the Court's question regarding whether EPA could set an emission limit of zero for existing coal generation based on a system of substituting coal generation with cleaner forms of generation. In that case, there was no question presented as to whether "commercial availability" is a legal requirement under Section 111, and accordingly EPA counsel's response cannot be understood as commenting on that question. In any event, this Court has never held that only technologies "already in place and successful within an industry" *at commercial-scale* are adequately demonstrated, and that interpretation would contravene legislative intent as discussed above.

analysis did not rest solely on consideration of technical feasibility, and the Agency explained how partial CCS could "reasonably be projected to be available to new sources at the time they are constructed." Portland Cement I, 486 F.2d at 391.

B. The Best System's Reliance on Downstream Sequestration of Captured CO_2 Is Consistent with the Act and Supported by the Record.

Petitioners suggest that because CO_2 captured at regulated steam units is typically stored "offsite and by third parties," EPA's selected Best System is not "appl[ied]" or "achiev[ed]" at the source and does not ensure that the pollutant is in fact "reduce[d]." Non-State Br. 39-40. Petitioners' argument ignores the fundamental design of air pollution control systems across source categories and is inconsistent with both the plain text and EPA's longstanding application of Section 111. Petitioners also ignore EPA's robust demonstration that captured CO_2 can be and has been securely stored.

Under Petitioners' reading, any system that "merely separates (rather than reduces)" the pollutant and then requires management "offsite" is not allowable under Section 111. Non-State Br. 40. But this interpretation would invalidate nearly every Section 111 standard of performance. Air pollution control devices routinely operate by removing air pollutants from a unit's emission stream and capturing them as a liquid or solid. See RTC 2.1-117, JA2080-82. Particulate matter, for example, may be captured by baghouses which trap particles as a dust, 80 Fed. Reg. at 64,555; see Sierra Club, 657 F.2d at 375; acid gases like sulfur dioxide are "scrubbed" from emissions using a chemical sorbent that reacts with the pollutant to generate a liquid slurry (wet scrubbing) or solid residue (dry scrubbing). See Sierra Club, 657 F.2d at 323-24. These captured pollutants must then be disposed as solid wastes, discharged as wastewater, or otherwise managed or reused. See 80 Fed. Reg. at 64,555; see also 80 Fed. Reg. 21,303, 21,340 (Apr. 17, 2015) (governing off-site disposal of solid wastes captured by air pollution controls at steam units); RTC 2.1-117, JA2080-82. Downstream management of captured pollutants is thus a commonplace feature of Section 111 standards. See, e.g., 75 Fed. Reg. 54,970, 55,022-23 (Sept. 9, 2010) (considering disposal of wastewater and solid waste from Section 111 standard for Portland cement plants).

The carbon capture technology at issue here is no different: CO_2 is scrubbed from the flue gas stream using a solvent, and then stored underground. 80 Fed. Reg. at 64,549 (describing CCS); Carbon Capture TSD 5-9, JA3126-30; see 80 Fed. Reg. at 64,555 (comparing CCS pollutant disposition to particulate or wet scrubber pollutant disposition). In all of these cases, the standard of performance reflects the quantity of a pollutant a unit must successfully remove from its emission stream, notwithstanding potential downstream management of the captured pollutant. It is not credible to suggest that Congress, in seeking to limit sources' emissions, would have disallowed the numerous, widespread pollution control technologies—like particulate matter controls and scrubber systems—which capture, but do not destroy, the pollutant before it is emitted. Thus, contrary to Petitioners' arguments, Non-State Br. 39-40, including CO_2 storage in the "best system of emission reduction" is fully consistent with Section 111(a)(1)'s requirement that EPA identify a system that regulated sources can "appl[y]" to "achiev[e]" their performance standard. See supra Statement of the Case I.A; cf. 42 U.S.C. § 7412(d)(2)(C) (specifying that hazardous air pollutant standards are "achievable" by sources through the "application" of measures that "capture" pollutants).

Petitioners further ignore the plain text of Section 111, which states that EPA must consider "nonair quality health and environmental impact" when determining the Best System. 42 U.S.C. § 7411(a)(1). That provision codified this Court's holding in Essex, which required that EPA "take into account counter-productive environmental effects" when determining the "best system," *including* "disposal problems" related to the best system's captured pollutants. 486 F.2d at 438-39; see, e.g., H.R. Rep. No. 95-294, at 190 (1977), reprinted in 1977 U.S.C.C.A.N. 1077, 1268-69, JA4616. There, the Court remanded the Section 111 standard because there was no evidence that EPA had considered "the significant land or water pollution potential resulting from disposal of the [scrubber system's] liquid purge byproduct." Essex, 486 F.2d at 438-39. Petitioners' theory is thus foreclosed by this Court's analysis in Essex and by Congress's codification of that decision.

Of course, a system of emission reduction that captured a pollutant only to re-emit it elsewhere would not be a best system. 80 Fed. Reg. at 64,539; RTC 2.1-117, JA2080-82. But EPA documented in its record that captured CO_2 can be safely managed from point of generation to its final disposition. See 80 Fed. Reg. at 64,590 (generally describing oversight of CO_2 storage), 64,582 (detailing Department of Transportation pipeline regulations), 64,586 (detailing requirements for monitoring, reporting, and verification plans), 64,583-86 (detailing injection well requirements under the Safe Drinking Water Act), and 64,586-88 (detailing how existing regulations prevent, monitor, and address potential leakage). EPA reasonably relied on these existing regulations when determining that there would be no meaningful health or environmental impacts related to the downstream sequestration of CO_2 captured at the regulated facilities, and that emissions "reduce[d]" at the source would not be re-emitted. Id. at 64,592-93.

Ultimately, because Petitioners "fail[] to distinguish capture and sequestration of carbon from every other [S]ection 111 standard which is predicated on capture of a pollutant," id. at 64,589, Petitioners' contentions that the Best System cannot be "appl[ied]" or "achi[eved]" by a source are unpersuasive.

C. EPA's Best System Determination Comports with the Energy Policy Act.

Contrary to Petitioners' argument, see State Br. 19-23; Non-State Br. 19-20, EPA's determination that CCS is adequately demonstrated is consistent with the EPAct. As described above, the EPAct included three provisions—Sections 402(i), 421(a), and 48A(g)—that somewhat limit EPA's ability to consider facilities receiving grants or tax incentives pursuant to the EPAct when assessing whether a technology is adequately demonstrated under Section 111. See supra Statement of the Case I.B. However, as explained further below, EPA's Best System determination was fully supported by non-EPAct facilities, and only referenced EPAct facilities as corroborative of, but inessential to, that determination. Accordingly, while EPA properly interprets the EPAct as allowing for consideration of EPAct-supported facilities under Section 111 provided such consideration is not the "sole" basis for an "adequately demonstrated" determination, this Court need not reach challenges to that interpretation here.

1. The Court need not interpret the EPAct because EPA's determination did not require consideration of EPAct facilities.

This Court need not address the scope of the EPAct's limitation on EPA's Best System determination because that determination did not rest on considering facilities supported under the EPAct. As shown in Argument I.A.1.a.i above, the performance of Boundary Dam alone is sufficient to support the conclusion that the Best System is adequately demonstrated. 80 Fed. Reg. at 64,550; see id. at 64,549-51. That finding is supported by the performance of additional facilities not receiving EPAct assistance, as well as by vendor guarantees of carbon capture technology's performance. See supra Argument I.A.1.a.ii. EPA specified that its identification of facilities receiving grants under EPAct Sections 402 and 421, see 80 Fed. Reg. at 64,551-52, was only "corroborative" of the "essential information" provided by non-EPAct facilities. Id.

at 64,548; see supra Argument I.A.1.a.iii.[25] Accordingly, Petitioners' arguments concerning EPAct limitations are irrelevant, and need not be reached by this Court.

2. EPA properly applied Sections 402(i) and 421(a), which limit but do not bar consideration of EPAct facilities.

To the extent the Court reaches issues concerning the relevant EPAct limitations, EPA properly applied them. Sections 402(i) and 421(a) of the EPAct plainly allow EPA to consider EPAct-supported facilities, for purposes of adequate demonstration, in some circumstances. Section 421(a) reads, in full:

> No technology, or level of emission reduction, shall be treated as adequately demonstrated for purpose [sic] of section 7411 of this title, achievable for purposes of section 7479 of this title, or achievable in practice for purposes of section 7501 of this title *solely by reason of* the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under section 13572(a)(1) of this title.

42 U.S.C. § 13573(e) (emphasis added). Section 402(i) is nearly identical (shifting only the order of the clauses and changing "shall be treated as" to "shall be considered to be"). See 42 U.S.C. § 15962(i); see also Memorandum to Section 111(b) Docket, July 29, 2015, Re: EPAct05 ("EPAct Memo"), 3-4 (demonstrating that Section 402(i)'s syntax requires the same reading even absent Section 421(a)), EPA-HQ-OAR-2013-0495-11334, JA3220-21. Petitioners claim that because Congress required that EPAct

[25] EPA's Best System determination did not consider any facilities receiving support under Section 48A(g), see 80 Fed. Reg. at 64,549-52, which is further addressed below, see infra at 56.

facilities not be the "sole" support for EPA's determination, Congress intended a "but-for" standard, where EPA "must show that it would have made the same decision in the absence of considering any EPAct-assisted facilities." State Br. 22.

As noted above, because EPA's Best System determination is adequately supported even without facilities receiving grants under Section 402(i) and 421(a), it would meet Petitioners' erroneous "but-for" reading. See 80 Fed. Reg. at 64,541. In any event, Petitioners' reading is inconsistent with the text's commonsense meaning, which allows EPA to consider EPAct facilities so long as these facilities are not the *sole*, or exclusive, support for EPA's determination. See Milner v. Dep't of Navy, 562 U.S. 562, 570 n.4 (2011) ("Information must 'relat[e] solely'—*meaning, as usual, 'exclusively or only*,' [Random House Dictionary 1354 (1966), JA4558]—to the agency's 'personnel rules and practices.'" (emphasis added)); EPAct Memo 4 & n.8, JA3221. This was the conclusion reached by the only court that has considered these provisions. Nebraska v. EPA, 2014 WL 4983678, at *4 (emphasis in original); see 80 Fed. Reg. at 64,541.

Moreover, Petitioners' reliance on two cases to support their interpretation of the word "solely" as it appears in the EPAct is misplaced. See State Br. 22. First, Petitioners cite Price Waterhouse v. Hopkins, 490 U.S. 228 (1989), for the proposition that "solely" indicates "but-for" causation. State Br. 22. But Price Waterhouse concerned Title VII employment discrimination—a materially different statutory scheme—and, in any case, was clarified by this Court in Ponce v. Billington, which held that "'sole' and but-for cause are very different." 679 F.3d 840, 845-46 (D.C. Cir. 2012). Petitioners similarly misapply the holding of Severino v. North Fort Myers Fire Control District, 935 F.2d 1179 (11th Cir. 1991). State Br. 22. The Eleventh Circuit held there that a firefighter had not been terminated "solely on the basis of his AIDS condition" even where it was "clear that the employment decisions were, in part, a response to the AIDS diagnosis." Severino, 935 F.2d at 1181-82.[26] Severino therefore supports EPA's conclusion that the term "solely" should be given its natural meaning—of "only" or "exclusively"—and does not imply a "but-for" standard.

EPA's application of the limiting provisions in the EPAct is consistent with their plain meaning. If the Court were to determine, however, that the provisions' meaning could not be discerned through "traditional tools of statutory construction," Chevron, 467 U.S. at 843 n.9, EPA's interpretation warrants deference under the second prong of the Chevron test. Id. at 843-44. While the limitations themselves appear in statutes otherwise administered by the Department of Energy and the Internal Revenue Service, see id. at 844, neither agency would ever have cause to interpret or apply these provisions. By contrast, the Administrator must do so as part of her routine interpretation and application of Section 111. See New York v. EPA, 413 F.3d 3, 30 (D.C. Cir. 2005) (deferring to EPA's judgments under Section 111).

[26] Petitioners' citation to Severino and accompanying parenthetical are to Judge Kravitch's *dissent*, not to the opinion of the court. See Severino, 935 at 1183 (Kravitch, J., dissenting).

The fact that the EPAct limitations were not written directly into Section 111(a)(1) does not alter the fact that Congress intended that EPA be the administering agency with respect to determinations that a technology is adequately demonstrated, and drafted these provisions to directly inform EPA's interpretation of that authority. Cf. United States v. City of Fulton, 475 U.S. 657, 662, 667 (1986) (granting the Department of Energy deference when interpreting a section of the Flood Control Act). EPA's reasonable interpretation of its authority under Section 111(a)(1), including the EPAct's limitation on that authority, is thus entitled to deference.

Finally, Petitioners err in claiming that EPA's Best System determination is contrary to the limitation in Section 48A(g). State Br. 20-21. Petitioners overlook that EPA did not consider any facilities supported under Section 48A(g) when determining the Best System, so that limitation has no application here and no further inquiry into its scope is necessary. See 80 Fed. Reg. at 64,549-52. Even if Section 48A(g) had some relevance, it should be read in context as creating the same limitation as Sections 402(i) and 421(a). Its instruction that no use of technology at a facility receiving tax credits "shall be considered to indicate that the technology" is adequately demonstrated does not bar any "consideration" whatsoever, see State Br. 21. Rather, it is best read as preventing a fact from being thought or deemed to prove a conclusion: here, preventing a technology from being deemed adequately demonstrated simply because of its use at an EPAct facility. See 80 Fed. Reg. at 64,541-42; EPAct Memo 5-6, JA3222-23; RTC 2.2-3, JA2158-59.

D. EPA Reasonably Determined That the Selected Standard for New Steam Units Is Achievable.

Contrary to Petitioners' argument, EPA reasonably assessed the achievability of the performance standard it finalized for new steam units—an annual average of 1,400 lb-CO_2/MWh-g. Non-State Br. 41-47. As EPA explained, this standard was calibrated to "reflect[] the degree of emission limitation achievable through the application of … a highly efficient [supercritical pulverized coal boiler] implementing partial CCS," i.e., the Best System. 80 Fed. Reg. at 64,573; Achievability TSD 1, JA2963. Because the studies EPA used to consider the system's cost assumed certain operating characteristics—e.g., that the unit would use bituminous coal—EPA "examine[d] the effects of deviating from those assumed operational parameters on the achievability of the final standard." 80 Fed. Reg. at 64,573.

First, EPA determined that operational fluctuations, startups, shutdowns and malfunctions should not prevent new units employing the Best System from meeting the standard. Achievability TSD 1-2, JA2963-64. EPA noted that compliance is measured over a 12-operating-month averaging period, which is "very forgiving of short-term excursions" that may temporarily change emission rates. Id. 1, JA2963. EPA further observed that new steam units likely would be built (if at all) "to serve base load power demand and would not be expected to routinely start-up or shutdown." Id.[27]

Next, EPA considered how variations in coal type would affect achievability. Achievability TSD 2-5, JA2964-67; see also infra Argument II (discussing lignite issues). Specifically, EPA used available data from DOE concerning projected partial carbon capture performance at units burning bituminous coal to estimate the performance curve at units burning low rank coal (subbituminous coal or dried lignite), an approach EPA considered reasonable because the equipment and configuration of the partial CCS system would be the same at such units. Achievability TSD 2, JA2964; see also id. 5, JA2967 (noting similar energy and water use regardless of coal type).

Finally, because the DOE studies EPA considered for its cost estimates assumed optimized "design emission rates" that DOE noted might be lower than actual plants' emission rates over time, EPA compared the design rates against the performance of recently-built plants to "assess[] the reasonableness of the reports' assumption." Id. 5, JA2967. For this comparison, EPA identified the best-performing units burning bituminous and low rank coal—the Longview Power plant

[27] Although the average annual capacity factor (i.e., the percentage of available hours that a plant is actually utilized to generate electricity) for the *existing* fleet of steam units is 53 percent, see Non-State Br. 43, it was reasonable for EPA to assume that investments in building new steam units were only likely if such units would be used to serve baseload demand.

in West Virginia and American Electric Power's Turk plant in Arkansas, respectively. Id. 6, JA2968. The Turk plant utilizes the ultra-supercritical configuration used in the performance estimates considered by EPA. RTC 6.3-247, JA2651 (noting that "the final [Best System] is a highly efficient supercritical [boiler] implementing partial CCS to meet a standard of 1,400 lb CO_2/MWh-g. [Turk] is an example of a highly efficient supercritical [boiler]"). The Turk plant's best monthly emission rate (1,725 lb-CO_2/MWh-g) is better than EPA's assumed uncontrolled (i.e., baseline) emission rate (1,737 lb-CO_2/MWh-g), Achievability TSD 6, JA2968, while its best and worst 12-operating-month averages were only slightly higher than the baseline. Id. Accordingly, EPA reasoned that by making modest performance improvements to match Turk's best documented monthly performance, a new plant would perform at the estimated rate. Reconsideration Memo 17, JA4426; Achievability TSD 6, JA2968; accord Sierra Club, 657 F.2d at 361-64 (upholding EPA's promulgation of a standard for new coal-burning plants set at a higher efficiency level than that achieved by any currently-operating plant, based on projected improvements).

Importantly, EPA also showed that even assuming *no* improvements to the baseline boiler performance, the standard could be achieved by increasing the rate of CO_2 capture above that assumed for purposes of the Best System determination. Specifically, EPA found that a new plant matching Turk's worst 12-operating-month emission performance would need a CO_2 capture rate of 27 percent rather than 23 percent. Reconsideration Memo 18, JA4427. EPA then found that the costs of implementing this degree of CO_2 capture remained reasonable, using the same metrics otherwise employed in its cost analysis. Id. 18-19, JA4427-28; see infra Argument I.E (discussing cost analysis).

Petitioners contend that it was improper for EPA to focus on the "best performing units" such as Turk, Non-State Br. 46; that EPA's data did not enable it to evaluate the full range of new steam units' operating conditions, id. 41-44; and that EPA did not evaluate the performance of the same "system of emission reduction" on which the standard is based, id. 44-46. None of these criticisms is valid.

A new source standard of performance under Section 111 must reflect the emission limitation achievable by the "best" system of emission reduction, not just an "average" plant's performance. See Non-State Br. 43 (arguing that the standard should have "account[ed] for" the emissions performance of an "average real unit"). In enacting this provision, "Congress was most concerned that new plants—new sources of pollution—would have to be controlled to the greatest degree practicable if the national goal of a cleaner environment was to be achieved." Essex, 486 F.2d at 434 n.14 (citing legislative history). Consistent with that intent, this Court has held that an "achievable" standard is one not set "at a level that is purely theoretical or experimental," but it "need not necessarily be routinely achieved within the industry prior to its adoption." Id. at 433-34; see also Portland Cement I, 486 F.2d at 391-92. Instead, the Act authorizes EPA to "hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard." Sierra Club, 657 F.2d at 364. Thus, it was entirely appropriate for EPA to focus on the best-performing existing steam units to determine whether new steam units could achieve its standard. Cf. NRDC I, 489 F.3d at 1369 ("best performing" source for purposes of 42 U.S.C. § 7412(d)(3) is the source with the lowest emission level).

National Lime did not depart from the Court's earlier case law on this issue, as Petitioners seem to suggest. See Non-State Br. 46; Nat'l Lime, 627 F.2d at 429 ("We have not deviated from the approach applied to the first [new source standard] to reach this court" in Portland Cement I), 431 n.46 (agreeing with Essex that "[a]n achievable standard need not be one already routinely achieved in the industry"). Rather, remand was necessary in National Lime because the Court found that EPA had not explained how the data it relied on represented the relevant range of operating conditions. 627 F.2d at 433. Here, EPA did so.

Importantly, the Court in National Lime explained that issues of achievability often hinge on cost consideration; that is, while it may be technically feasible to improve performance, there is an additional cost in doing so. Id. at 431 n.46. Here, there is no question that the 1,400 lb-CO_2/MWh-g standard can feasibly be met, but if doing so requires greater CO_2 capture due to variable boiler performance, there is likewise an additional cost. Accordingly, EPA further examined this issue by conservatively quantifying the amount of additional CO_2 capture that might be needed assuming the worst documented 12-operating-month performance of a highly efficient supercritical boiler; assessing what the cost of that additional CO_2 capture would be; and showing why that (hypothetical) cost would remain reasonable. Reconsideration Memo 17-19, JA4426-28; see also DOE, Cost and Performance Baseline for Fossil Energy Plant Supplement: Sensitivity to CO_2 Capture Rate ("DOE Supplement") 1 (stating that designing for lower emission rates "does not have major cost implications" because the cost slope for supercritical pulverized coal plants is not steep), EPA-HQ-OAR-2013-0495-11340, JA3468. Petitioners do not challenge this analysis (and, in fact, do not even mention it).

The "McCutchen Letter"[28] also does not support a different interpretation of Section 111 from that expressed by this Court. See Non-State Br. 6, 46. That letter, sent by an EPA staff official to his state colleague, responded to questions arising in a different context—the case-by-case determination of "best available control technology" for specific permits. McCutchen Letter, JA4629-30; see 42 U.S.C. §§ 7475(a)(4), 7479(3). The letter stated, correctly, that individualized facility permitting decisions may result in more stringent emission limitations than those in the applicable nationwide standard, because the permitting analysis considers site-specific factors that may support a greater degree of emission reduction at particular sources.

[28] Letter from Gary McCutchen, Chief, New Source Review Section, Office of Air Quality Planning & Standards, EPA, to Richard E. Grusnick, Chief, Air Division, Ala. Dept. of Env'tl Mgmt. (July 28, 1987), JA4629-30.

McCutchen Letter, JA4629; accord, e.g., 80 Fed. Reg. at 64,632. The letter further explained that a finalized nationwide standard creates a "legal 'floor,'" such that the emissions limitation in each permit must be at least equally if not more stringent. McCutchen Letter, JA4629; accord 42 U.S.C. § 7479(3); 80 Fed. Reg. at 64,631. But nothing in the letter purports to address, let alone reconsider, the principle—by then well-established in the Court's jurisprudence—that the nationwide standard itself may be "technology-forcing" and thus may appropriately be based on advances in design or operational improvements that are projected to be within the capability of new sources.

Petitioners next contend that the DOE cost and performance studies EPA considered did not permit evaluation of the full range of potentially relevant operating conditions, because they assumed a specific set of conditions. Non-State Br. 41-44; see also Int. Br. 16. However, EPA did not rely *solely* on the DOE studies; rather, it used them in conjunction with best performing plants' actual emissions data, accounting for variability as explained above. Petitioners assert that EPA failed to account for degradation in efficiency over time, Non-State Br. 44, but EPA's cost estimates included the cost of maintaining the entire system. DOE Cost and Performance Baseline 41-42, 91, 114, 136, 159, JA3532-33, JA3582, JA3605, JA3627, JA3650. Thus, unlike in National Lime, EPA reasonably explained how its data was representative of relevant operating conditions for new steam units.

Petitioners' remaining objection is that the Turk plant that EPA identified as the best-performing low rank coal-burning unit employs an "ultra-supercritical" boiler, which Petitioners claim is different from the "highly efficient supercritical boiler" that EPA determined was part of the Best System for new steam units. Non-State Br. 45-46; see, e.g., 80 Fed. Reg. at 64,548. This objection elevates semantics over substance. As EPA explained at proposal, and again in denying reconsideration, "supercritical" coal-fired boilers are those "designed and operated with a steam cycle above the critical point of water." Reconsideration Memo 20 (citing 79 Fed. Reg. at 1468 n.176), JA4429; see also 80 Fed. Reg. at 64,594 nn.507, 512. "*Any* boiler that operates above the critical point of water is a supercritical boiler," and "[a]djectives such as 'ultra' or 'advanced'" simply describe "units that are more advanced or more efficient than units operating with steam conditions that are just slightly above the thermodynamic critical point." Reconsideration Memo 20, JA4429. In other words, the terms "ultra-supercritical" and "highly efficient supercritical" are not meaningfully distinct in this context. Id.

More important than the semantics is the level of performance. Id. The best historic 12-operating-month emission rate at the Turk plant, (1,753 lb-CO_2/MWh-g) is nearly identical to the assumed baseline rate for new low rank coal-burning units (1,737 lb-CO_2/MWh-g), id. 17-18, JA4426-27, and Petitioners identify nothing about the design of this plant that made it unreasonable for EPA to project that newly constructed units can similarly "incorporate the more efficient ultra-supercritical technology," id. 17, JA4426.

E. EPA Reasonably Took Costs and Other Factors Into Account and Reasonably Declined to Rely on Monetized Benefit-Cost Analysis in Determining the Best System.

As part of determining the "best system of emission reduction adequately demonstrated," EPA must "tak[e] into account the cost of achieving such reduction." 42 U.S.C. § 7411(a)(1). EPA reasonably did so here in determining that partial CCS is part of the Best System for new steam units. And while EPA did not—nor was required to—rely on monetary benefit-cost analysis as the basis for its determination, the record shows that EPA reasonably considered benefits as well.

1. EPA reasonably determined that the costs of partial carbon capture and storage for new steam units were not exorbitant and that energy impacts were acceptably low.

This Court has interpreted Section 111's requirement to "take[] into account the cost of [emission] reduction" to mean that EPA may not adopt a standard of performance if its cost would be "exorbitant," "greater than the industry could bear and survive," "excessive," or "unreasonable." 80 Fed. Reg. at 64,538 (citing Lignite Energy Council, 198 F.3d at 933; Portland Cement Ass'n v. Train ("Portland Cement II"), 513 F.2d 506, 508 (D.C. Cir. 1975); and Sierra Club, 657 F.2d at 343). Section 111 does not, however, "provide specific direction regarding what metric or metrics to use in considering costs." 80 Fed. Reg. at 64,539. This Court repeatedly has emphasized that EPA has "considerable discretion" in taking cost into account when setting standards of performance, and "[b]ecause [S]ection 111 does not set forth the weight that should be assigned" to each enumerated factor, the Court has "granted [EPA] a great degree of discretion in balancing them." Lignite Energy Council, 198 F.3d at 933; New York v. Reilly, 969 F.2d 1147, 1150 (D.C. Cir. 1992); see also 80 Fed. Reg. at 64,538-39 (citing other cases).

Here, EPA carefully considered the costs of CCS both at the individual plant level—using two different well-accepted metrics for comparing the costs of new plants—and across the industry, applying conservative assumptions throughout its analysis. For example, EPA's Best System determination incorporated the assumption that *none* of the costs of carbon capture would be defrayed by selling captured CO_2 for enhanced oil recovery, even though power plant carbon capture projects to date generally have involved such sales. 80 Fed. Reg. at 64,564; RIA 5-17 n.19, JA2917.[29] EPA's analysis was also conservative because "there exist other less expensive means of meeting the promulgated standard"; thus, "EPA may be overestimating actual compliance costs." 80 Fed. Reg. at 64,565.

[29] Enhanced oil recovery opportunities were considered in the monetized benefit-cost analysis set forth in Chapter 5 of EPA's Regulatory Impact Analysis. E.g., RIA 5-17, JA2917. As discussed further below, that analysis was performed pursuant to an Executive Order requirement but was not used to assess the reasonableness of the standard's costs. Infra Argument I.E.2.

a. Unit-level capital costs and consideration of energy impacts.

At the individual unit level, EPA examined: (1) the incremental capital cost to a new steam unit of achieving the standard using partial CCS, consistent with "extensive comment from industry representatives and others" urging that the Agency focus on capital costs, id. at 64,559; and (2) the "levelized cost of electricity" associated with building a new steam unit either with or without partial CCS, id. at 64,560.[30] Both of these metrics supported EPA's conclusion that the costs of partial CCS are reasonable.

Using the first metric, EPA found that a new steam unit implementing partial CCS would incur an incremental capital cost increase (compared to a new unit without partial CCS) of 21 to 23 percent, depending on coal type and the resulting amount of carbon capture needed. 80 Fed. Reg. at 64,560 & n.263 (noting a 21 to 22 percent capital cost increase for units burning bituminous coal, and 23 percent for units burning low rank coal).[31] EPA observed that this increase is consistent with

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[30] The levelized cost of electricity is a "summary metric" that takes into account all costs to construct and operate a new power plant over an assumed time period and an assumed capacity factor, and is expressed as the full cost of generating electricity on a per unit basis (e.g., dollars per megawatt-hour). Id.; see also RIA 4-20–4-21, JA2883-84.

[31] This cited preamble page includes a table showing increases in "total overnight cost" and "total as-spent capital." Id. at 64,560 (Table 7). The latter represents the sum of all capital expenditures, including interest, as they are incurred during the capital expenditure period and is the most appropriate measure for purposes of EPA's analysis of capital cost, because it shows the cost to build a power plant with and

(Footnote Continued …)

(albeit at the high end of) the range of capital cost increases associated with past Section 111 standards that this Court sustained as reasonable. 80 Fed. Reg. at 64,560. For example, the 1978 new source performance standard upheld in Sierra Club, 657 F.2d at 410, was estimated to increase capital costs for new coal-fired power plants by as much as 20 percent and was expected at the time to result in "utilities … hav[ing] to spend tens of billions of dollars by 1995 on pollution control." Id. at 314; 80 Fed. Reg. at 64,560. The 1971 standards for new coal-fired plants upheld in Essex, 486 F.2d at 440, were estimated to increase capital costs by nearly 16 percent. See 80 Fed. Reg. at 64,559-60. Thus, the degree of incremental capital cost associated with partial CCS is "comparable in magnitude on an individual unit basis" with the incremental capital costs estimated for the same industry under earlier standards. And, importantly, the costs of those earlier standards ultimately did not cause any significant adverse financial impacts to the utility industry. Id. at 64,560.

Petitioners make reference to a "31 percent" increase that appears elsewhere in the record—specifically, in the "capital cost" element of the levelized cost of electricity. See Non-State Br. 36 (citing RIA 4-24 (Table 4-5), JA2887). However,

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without partial CCS. See, e.g., American Electric Power Comments, EPA-HQ-OAR-2013-0495-10618, JA636-38; see also DOE Supplement 18 (Ex. A-3) (presenting the total overnight cost and total as-spent capital cost dollar figures used in the preamble), JA3485; DOE Cost and Performance Baseline 39-40 (explaining these terms), JA3530-31.

that is not the most appropriate indicator of capital cost,[32] and EPA did not use the levelized cost of electricity metric to compare the capital costs of building a power plant with and without partial CCS. See 80 Fed. Reg. at 64,560-63 (explaining how EPA used levelized cost); infra Argument I.E.1.b (same).

Petitioners' criticism of EPA's capital cost analysis also mistakenly refers to an estimated "energy penalty" of "30 percent" (i.e., the portion of total electricity output needed to power the CCS equipment), which is associated with *full* CCS, not with the partial CCS option that EPA determined was the Best System. Non-State Br. 36-37. The energy penalty calculated for partial CCS with a 16 percent capture rate was only 6.3 percent, which is comparable to the "5-6 percent" combined energy penalty associated with "state-of-the-art controls for nitrogen oxides and sulfur dioxide" that Petitioners consider to be acceptably low. Non-State Br. 37; see 80 Fed. Reg. at 64,593 (Table 14).[33] And, contrary to Petitioners' assertion, EPA took account of the Rule's energy impacts. See 80 Fed. Reg. 64,593-94; RTC 6.3-50, 6.3-274, 6.3-401, JA2530, JA2685, JA2742. In short, Petitioners identify nothing about EPA's analysis of capital costs or energy requirements that could be considered "arbitrary."

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[32] See supra 67-68 n.31.

[33] Petitioners likewise conflate full and partial CCS when referring to the testimony of Deputy Assistant Energy Secretary Friedmann, as his testimony concerned full CCS. State Br. 33; see 80 Fed. Reg. at 64,557 & n.246.

b. Levelized cost of electricity.

EPA evaluated the second unit-level cost metric, the levelized cost of electricity of building a new steam unit with partial CCS, by comparing it with the levelized cost of new nuclear construction. 80 Fed. Reg. at 64,560-63. Although Petitioners disagree with using new nuclear construction as a point of comparison, Non-State Br. 37-38, EPA explained that comparison is appropriate "where the facilities being compared would serve load in a similar manner." 80 Fed. Reg. at 64,561. Specifically, EPA compared the levelized cost of technologies "that would be reasonably anticipated to be designed, constructed, and operated for a similar purpose—that is, to provide dispatchable base load power that provides fuel diversity by relying on a fuel source other than natural gas." Id. at 64,562. New nuclear construction provided the most apt comparison because it is "the principal other alternative [besides coal] to natural gas to provide new base load power." Id. at 64,562. Conversely, other types of new units would not provide fuel diversity, or are not dispatchable (e.g., sources such as wind and solar that cannot be readily ramped up or down to meet demand). Id.

Moreover, despite Petitioners' contentions that new nuclear is, itself, an "exorbitant[ly]" expensive technology (so a favorable comparison would not necessarily indicate that the Rule's costs are reasonable), Non-State Br. 37, EPA cited record evidence that "utilities have been willing to pay a premium for nuclear power in certain circumstances, as indicated by the recent new constructions of nuclear facilities and by [integrated resource plans[34]] that include new nuclear generation." 80 Fed. Reg. at 64,563; see id. at 64,526 & n.80 (citing Review of Electric Utility Integrated Resource Plans – Technical Support Document, EPA-HQ-OAR-2013-0495-11775, JA3187-3217). EPA observed that utilities may likewise be willing to pay a premium for new coal-fired generation capacity with partial CCS "as a hedge against the possibility that future natural gas prices will far exceed projected levels." 80 Fed. Reg. at 64,563.[35]

Having thus established the relevance of its cost comparison with new nuclear, EPA found that the levelized cost of a new steam unit with partial CCS "is within the range of the [levelized cost]" of the comparable alternative generation sources. Id. at 64,561. Specifically, the levelized cost of new steam with partial CCS was estimated to be $92 to $121 per megawatt-hour, while the levelized cost of new nuclear was estimated to be $87 to $132 per megawatt-hour, a "substantially similar" range. Id. at

[34] "[Integrated resource plans] are used by utilities to plan operations and investments in both owned generation and power purchase agreements over long time horizons." 80 Fed. Reg. at 64,559. Although such plans "do not demonstrate a utility's intent to pursue a particular generation technology, they do indicate the types of … technologies that a utility would consider for new generating capacity." Id. Because integrated resource plans are "legally mandated and play a role in state public utility commission determinations," it is reasonable for EPA to consider them. RTC 3.3-28, JA2276.

[35] EPA also analyzed whether new nuclear and new coal-fired generation would be available in deregulated energy markets, and explained why States might select one of these alternatives notwithstanding cost considerations, even in such markets. RTC 3.3-3, JA2251-52.

64,562 (Table 8). The levelized cost analysis thus reasonably "demonstrate[d] that the final standard's costs are in line with power sources that provide analogous services—dispatchable base load power and fuel diversity." Id. at 64,563.[36]

Petitioners nonetheless contend that EPA's levelized cost comparison was arbitrary because EPA purportedly "disregarded" the higher-than-planned costs of the under-construction Kemper gasification facility, which is designed to use CCS at a 65 percent capture rate. See Non-State Br. 37-38; State Br. 32-33. EPA in fact carefully considered the cost overruns at Kemper, but found that they related to the facility's gasification technology, not its carbon capture system, and that they stemmed largely from "highly idiosyncratic circumstances"—such as management decisions "contrary to normal protocols"—that would not be replicated at other plants. Independent Monitor's Prudency Evaluation Report 5-6, 10-16, EPQ-HQ-OAR-2013-0495-11412, JA3859-60, JA3864-70; 80 Fed. Reg. at 64,571 & n.335 (citing that report); RTC 6.3-247, 6.3-272, 6.3-320, JA2649-50, JA2682-83, JA2715. The experience at Kemper therefore does not undermine the conclusions EPA reached concerning partial CCS costs.

[36] Moreover, although a new nuclear or compliant coal unit may be viewed as expensive when compared to a new gas-fired unit on a stand-alone basis, for utilities or states seeking the benefit of fuel diversity or a hedge against possible future natural gas price increases, the appropriate frame of analysis is not the unit itself but rather the power generation fleet as a whole. From this standpoint, the addition of a new nuclear or compliant coal unit may improve the overall profile of the fleet for only a small percentage increase in total system costs.

c. Industry-wide economic impacts.

Finally, EPA considered the overall cost and economic impact of the standard, taking into account current economic conditions across the utility industry. 80 Fed. Reg. at 64,563-64. Even without this Rule, the cost to build and operate gas-fired units has fallen well below the cost to build and operate coal-fired units. RIA 4-28 (Figure 4-3), JA2891. As a result, capacity additions of coal-fired generation are projected to remain significantly lower for many years to come. Id. 4-10 (Table 4-1), JA2873; see generally id. 4-10–4-20, JA2873-83. EPA thus found that the only new coal capacity predicted to come on line until 2022 (the last year it analyzed for this purpose[37]) would be already-planned capacity that includes carbon capture. See 80 Fed. Reg. at 64,563 & nn.281-82. EPA did not use these facts "to negate consideration of cost," id. at 64,559 n.254; on the contrary, it rejected full CCS as the Best System expressly due to its cost, and it carefully evaluated the unit-level costs of partial CCS as described above. Id. at 64,559 n.254. Nonetheless, these overall market trends reasonably led EPA to conclude that the Rule would impose "negligible costs overall" and would not "have significant effects on fuel markets, electricity prices, or the economy as a whole." Id. at 64,563.

[37] Because the Act requires EPA to review new source standards every eight years, EPA reasonably selected the year 2022 (encompassing an eight-year timeframe from the proposal) as its analytical endpoint. RIA 1-5, JA2799.

Petitioners maintain that natural gas prices may rise to a degree that would make new coal cost-competitive but for the cost of partial CCS, and contend that this possibility invalidates EPA's reasoning. Non-State Br. 38-39; State Br. 31. EPA considered a series of sensitivity analyses to evaluate if there is indeed any realistic possibility that new coal-fired capacity without CCS could become cost-competitive with gas-fired generation. These analyses, performed by the Energy Information Administration, indicate that even under a series of highly unlikely assumptions that favor coal, new coal plants would still not be competitive with natural gas. Specifically, these analyses considered the possibility of higher economic growth (2.8 percent annually through 2040); lower coal prices based on lower wages, lower manufacturing and transport costs, and greater mining productivity (while adding no risk premium for greenhouse gas liability); and 50 percent lower oil and natural gas resources. RIA 4-9, 4-13–4-14 (Table 4-3), JA2872, JA2876-77. Even with all of these assumptions built in, "[n]one of these sensitivity cases forecast unplanned additions of coal-fired capacity without CCS in the analysis period." Id. 4-9, JA2872. Natural gas prices would have to exceed $11 per million British thermal units—a price much higher than any of the long-term term price forecasts Petitioners cite, Non-State Br. 38-39[38]—for the levelized cost of new coal plants to even "approach[] parity" with

[38] The Court should disregard the post-record evidence Petitioners cite from September 2016, months after EPA denied reconsideration. Non-State Br. 38-39. Nonetheless, that evidence does not contradict EPA's analysis. As shown in the

(Footnote Continued …)

new gas-fired generation. RIA 4-29–4-30, JA2892-93. Such a price has not been seen since 1996, well before the advent of hydraulic fracturing, which has radically lowered natural gas pricing. RTC – Chapter 3, 3.7-3, EPA-HQ-OAR-2013-0495-11862, JA2348. Hence, EPA reasonably concluded that natural gas prices do not have to continue at currently low levels for gas to maintain its economic advantage over coal-fired generation. Id. 3.7-3, JA2348; see also id. 3.3-3, 3.3-16a, 3.4-5, JA2251, JA2262-63, JA2322-23.

2. EPA reasonably took cost into account without using monetized benefit-cost analysis to determine the Best System.

Petitioners also contend that the Rule is unlawful because EPA purportedly failed to "engage in … reasoned cost-benefit analysis." State Br. 31; see id. 29-32. They argue that because EPA assumed there will not be substantial construction of new coal capacity in the coming years, EPA "dramatically underestimated the Rule's costs." State Br. 32-33. They also claim that, by concluding that significant new coal capacity additions are not expected in the U.S. in the foreseeable future, EPA "effectively concede[d]" that the Rule is not "necessary" under the Act's general

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record, even with "an $11.02/MMBtu annual real price in 2013 and a $13.81/MMBtu real price in 2040…a representative [gas-fired] unit would have a lower levelized cost of electricity than a non-compliant [without CCS] coal unit." RIA 4-30, JA2893. The highest projected future natural gas price in the non-record report Petitioners cite is only $8.00/MMBtu, and that projection is made only in a sensitivity analysis. Non-State Br. 39.

rulemaking authority provision in 42 U.S.C. § 7601(a)(1), as it will not lead to significant "quantified benefits." State Br. 31. Neither criticism is valid.[39]

As shown above, this Court has long interpreted Section 111(a)(1) to leave EPA substantial discretion to determine how it should "tak[e] into account the cost of achieving [emission] reduction" when establishing a standard of performance. 42 U.S.C. § 7411(a)(1); supra Argument I.E.1. Consistent with that interpretation, the Court has held that Section 111 does not require EPA to use a monetized benefit-cost comparison to determine a standard of performance. Portland Cement I, 486 F.2d at 387; Essex, 486 F.2d at 437; see RTC 3.3-53, JA2307 ("The broad delegation to take cost into account [under 42 U.S.C. § 7411(a)(1)] eschews any particular method or metric for doing so."). The Court has also emphasized in the context of other CAA provisions that where the Act does not mandate a specific method of analyzing costs, EPA retains great discretion in how to do so. See, e.g., Husqvarna AB v. EPA, 254 F.3d 195, 199-200 (D.C. Cir. 2001); Nat'l Ass'n of Clean Water Agencies v. EPA, 734 F.3d 1115, 1156-57 (D.C. Cir. 2013); Natural Res. Def. Council v. EPA ("NRDC II"), 749 F.3d 1055, 1060 (D.C. Cir. 2014); see also 80 Fed. Reg. at 64,539 & n.144. Most recently, the Supreme Court has held that where a CAA provision required EPA to

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[39] These arguments contradict one another. Petitioners' view appear to be that it is reasonable to assume there will be no significant new coal capacity additions when quantifying benefits (thus their view that the Rule is not "necessary"), but *not* when quantifying costs. In any event, as discussed below, Section 111 does not mandate a monetized benefit-cost comparison, and EPA reasonably used a different approach to take costs into account.

regulate power plants if it "finds such regulation is appropriate and necessary," that language did not unambiguously require EPA "to conduct a formal cost-benefit analysis in which each advantage and disadvantage is assigned a monetary value" in order to make the predicate finding. Michigan v. EPA, 135 S. Ct. 2699, 2706, 2711 (2015); see 42 U.S.C. § 7412(n)(1)(A).

Here, EPA reasonably took costs into account using the approaches described above: by analyzing the incremental capital costs of the Best System, as many industry commenters advocated; by comparing the levelized cost of electricity of new coal with partial CCS to that of the most similar alternative new generation source; and by evaluating the economic impact of the standard of performance on the industry as a whole. Supra Argument I.E.1.

EPA also performed a monetized benefit-cost analysis, which is set forth in its Regulatory Impact Analysis, but did so only for purposes of complying with Executive Order 12,866 § 1 (Sept. 30, 1993).[40] RTC 3.2-7, JA2211; see RIA 5-1–5-25, JA2901-25. As EPA explained, it "does not use a benefit-cost test (i.e., a determination of whether monetized benefits exceed costs) as the sole or primary

[40] EPA's compliance with this executive order—and with Executive Order 13,563 (Jan. 18, 2011), cited by Petitioners (State Br. 30-31)—is not reviewable. See Executive Order 12,866 § 10 (Sept. 30, 1993), JA4642 (This order "is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or equity by a party against the United States …"); Executive Order 13,563 § 7(d), JA4839 (identical language); Air Transp. Ass'n of Am. v. FAA, 169 F.3d 1, 7 (D.C. Cir. 1999) (identical language in another executive order foreclosed judicial review).

decision tool when required to consider costs or to determine whether to issue regulations under the [Act], and is not doing so here." RTC 3.2-7, JA2211; see also Consideration of Costs and Benefits Under the Clean Air Act, EPA-HQ-OAR-2013-0495-11333, JA3224-25.

By using the cost-reasonableness analyses described above and declining to use monetized benefit-cost analysis in setting the standard, EPA did not "consider … costs [only] in a vacuum," fail to consider the Rule's "cost[s] at the margin," or fail to consider "the existing regulatory and market baseline," as Petitioners suggest. State Br. 30-31. In evaluating capital costs, for example, EPA focused expressly on the "incremental"—i.e., marginal—capital costs that partial CCS would add to the construction of new coal-fired units. 80 Fed. Reg. at 64,559. EPA considered such costs not in a vacuum, but rather in the context of earlier standards of performance under the same statutory provision, imposing similar incremental costs, which new sources in the same industry had been able to meet without adverse economic consequences. Supra Argument I.E.1.a. And EPA clearly identified the "baseline" unit-level costs and utility market economic conditions as part of its analyses. See, e.g., RIA 4-7–4-13, JA2870-76 (summarizing "base case" power sector modeling projections); id. 4-26–4-28 & Figure 4-3, JA2889-91 (identifying levelized cost of electricity for new coal units without CCS); 80 Fed. Reg. at 64,560 (Table 7) (identifying capital costs of new coal unit without CCS). Accordingly, the record for this Rule has nothing in common with the cases Petitioners cite, where agencies generally failed to give *any* consideration to costs at all. See Michigan, 135 S. Ct. at 2711 (holding that it was unreasonable to treat cost as "irrelevant" to determining whether regulation was "appropriate and necessary"); Bus. Roundtable v. SEC, 647 F.3d 1144, 1151 (D.C. Cir. 2011) (Securities and Exchange Commission assumed categorically that any costs were attributable to effect of state law rights rather than its rule); Am. Equity Inv. Life Ins. Co. v. SEC, 613 F.3d 166, 177-78 (D.C. Cir. 2009) (Commission was required to consider rule's effect on competition, but failed to disclose a rationale for its conclusion that competition would increase).

Likewise, EPA considered the significant emission reduction potential of the selected Best System, a critical environmental and public welfare benefit of the Rule. 80 Fed. Reg. at 64,574; see Essex, 486 F.2d at 437 (Congress "inten[ded] that new plants be controlled to the maximum practicable degree") (quotation omitted); Sierra Club, 657 F.2d at 326 (EPA must consider "the amount of air pollution as a relevant factor to be weighed when determining the optimal standard").[41] While EPA reasonably concluded that significant new added coal-fired capacity was not likely to be built in the foreseeable future with or without the Rule, it also "recognize[d] that some companies may choose to construct coal … units" and "set standards for these units accordingly." 80 Fed. Reg. at 64,642. EPA found that the emission reductions

[41] Thus, while Section 111(a)(1) does not require quantitative weighing of costs and monetized benefits, it does require EPA to consider, among other factors, "cost" and amount of emission reduction.

from *just one* new steam unit utilizing a highly efficient supercritical boiler and partial CCS, compared with a highly efficient unit that does not employ partial CCS, would be about 354,000 metric tons per year. Id. at 64,574. That is equivalent to taking about 75,000 vehicles off the road each year, and would add up to more than 14 million fewer metric tons of CO_2 emitted over the plant's lifetime. Id. Accordingly, for any new coal-fired unit that may actually be built in the coming years notwithstanding the economic trends documented by EPA, the Agency concluded that the emission reductions obtained by complying with the Rule are "meaningful and significant." Id.; cf. Massachusetts, 549 U.S. at 523-24 (rejecting argument that requested greenhouse gas endangerment finding was too "small" and "incremental" an action, given the global scale of the problem of climate change, to support standing).

EPA also noted American Electric Power's statements "that CCS is important for the very future of the [coal] industry: '[American Electric Power] still believes the advancement of CCS is critical for the sustainability of coal-fired generation,'" and its further comments that federal requirements to reduce greenhouse gas emissions were needed to create regulatory certainty and to facilitate investments in advancing and deploying CCS technology. 80 Fed. Reg. at 64,572 & n.337; see Sierra Club, 657 F.2d at 346 (under Section 111(a), EPA may consider how a proposed standard will encourage technological innovation); see also Reconsideration Memo 38 (noting that "[a]n unpredecented coalition of major industrial entities" recently stated that "without widespread deployment" of CCS, "we will simply fail to meet global mid-century goals for mitigating carbon emission from electric power generation and a wide range of industrial activity"), JA4447. EPA agreed, stating that the Rule "sends a strong signal that low-emitting coal-burning capacity is feasible, and that coal can thereby have an important place in a lower-carbon energy future." RTC 3.4-2, JA2320. Thus, EPA did not just focus on the Rule's "disadvantages" (i.e., its cost) from an industry perspective, but also its potential "advantages." See Michigan, 135 S. Ct. at 2707, 2711 ("[R]easonable regulation ordinarily requires paying attention to the advantages *and* the disadvantages of agency decisions." (emphasis in original)).[42]

In summary, EPA's determination of the standard of performance for new steam units was reasonable and consistent with this Court's jurisprudence, and therefore should be upheld.

II. EPA APPROPRIATELY DECLINED TO SUBCATEGORIZE FOR LIGNITE-BURNING UNITS.

EPA reasonably determined that the Best System was adequately demonstrated and achievable for all steam units, including units burning lignite coal.[43] Petitioners'

[42] If a quantified, monetized benefit-cost comparison was required, the record shows that even a conservative estimate of the benefits here would outweigh costs under most likely scenarios. See generally RIA 5-11–5-23, JA2911-23; RTC 3.3-53, 3.4-1, 3.4-2, 3.4-5, JA2307, JA2314, JA2319-21, JA2322-23.

[43] Lignite has a higher moisture content than other coal types, making it a less efficient fuel and a greater relative source of CO_2 emissions. See Coal Upgrading Memo ("Coal Memo"), 1, EPA-HQ-OAR-2013-0603-0046 (Attachment), JA4246; 80 Fed. Reg. at 64,600; Achievability TSD 3 (Table 1), JA2965.

and Intervenors' contentions otherwise, N.D. Br. 9-10, 13-18; Int. Br. 11-25, ignore that the Boundary Dam facility is lignite-burning, misstate the record on efficiency measures available at lignite-burning units, and distort precedent for subcategorization of lignite units. In addition, because lignite-burning units can meet the standard, the Rule does not implicate alleged constitutional concerns.

A. CCS Is Adequately Demonstrated for Lignite-Burning Units, Like Boundary Dam.

CCS is adequately demonstrated for lignite-burning units. Indeed, the Boundary Dam facility itself burns lignite. As demonstrated above, Petitioners' and Intervenors' critiques that Boundary Dam is unrepresentative or unreasonably costly, Int. Br. 11-14; N.D. Br. 9-12, are meritless. See supra Argument I.A.1.a.i.[44]

B. Lignite-Burning Units Can Achieve EPA's Standard of Performance.

The Rule's CO_2 performance standard for new steam units (1,400 lb-CO_2/MWh-g) is achievable at lignite-burning units. Units burning low rank coal (subbituminous or lignite) can apply the same CCS "equipment and configuration" as units burning higher rank coals. Achievability TSD 2, JA2964. EPA did recognize, though, that lignite and lignite-burning units have distinctive features that increase

[44] Intervenors' insistence that CCS is not adequately demonstrated for lignite is also undercut by their recitation of numerous state regulatory programs addressing CCS for lignite units. Int. Br. 5-8. This regulatory infrastructure, ranging from sales tax exemptions to liability measures to establishment of an offshore CO_2 repository, id., reflects that states believe CCS can be successfully applied to lignite-burning units.

their CO_2 emissions. 80 Fed. Reg. at 64,574. Accordingly, EPA considered DOE information on the influence of these features on the performance of a highly efficient boiler burning low rank coal, and concluded that a new lignite-fired supercritical boiler "would have an uncontrolled emission rate about 7 percent higher than a similar unit firing typical bituminous coal." Id.[45] As a result, EPA calculated that lignite-burning units can meet a performance standard of 1,400 lb-CO_2/MWh-g by capturing approximately 23 percent of their CO_2, compared to 16 percent for units burning high rank coals. See Achievability TSD 3, JA2965.[46]

EPA further determined that the cost of meeting 23 percent capture at lignite-burning units was reasonable. See 80 Fed. Reg. at 64,574. In particular, EPA calculated that implementation of this capture rate would increase the capital costs of units burning low rank coal by 23 percent (compared to 21 percent for units burning bituminous coal), which it determined was "reasonably consistent with capital cost

[45] Intervenors claim that EPA ignored features particular to lignite-burning units—like "different design requirements for the boiler, the plant footprint, and the emissions controls" and "greater parasitic load." Int. Br. 20. But these features are either irrelevant, given the fact that the CCS "equipment and configuration" would be the same, or already accounted for in EPA's determination that a lignite unit's uncontrolled emissions rate would be 7 percent higher. Moreover, EPA determined that new dried lignite boilers would be smaller and more cost-effective than existing boilers built for undried lignite. Coal Memo 1, JA4246; see also Achievability TSD 5 (discussing energy and water requirements), JA2967; supra Argument I.E.1.a at 68-69 (debunking Petitioners' claims regarding parasitic load or "energy penalty").

[46] Intervenors argue, in passing, that actual emission rates at steam units are "far higher" than the baseline rates EPA used to make this assessment. Int. Br. 16-17. As explained above, EPA reasonably assessed both DOE studies and actual emission rates in setting the standard. See supra Argument I.D.

increases in previous [new source performance standards]—including those in the power sector." Achievability TSD 5, JA2967; 80 Fed. Reg. at 64,574; see also supra Argument I.E.1.a. EPA also found that the levelized cost of electricity from a unit burning low rank coal and using 23 percent capture would be $95 to $121 per megawatt-hour, which is comparable to the $92 to $117 per megawatt-hour cost for a bituminous-burning unit. 80 Fed. Reg. at 64,562 & n.275. As further elucidated above, the predicted cost for lignite-burning units is reasonable because it is comparable to other technologies selected as a hedge against natural gas prices or to preserve fuel diversity. Id. at 64,574; see supra Argument I.E.1.b. In short, EPA reasonably concluded that the CO_2 performance standard for new steam units is achievable at lignite-burning units, accounting for costs associated with a small additional amount of CO_2 capture.

Intervenors assert that EPA erred because it assessed low rank coal types (subbituminous and lignite) together, even though undried (or "virgin") lignite has higher emissions than subbituminous coal. Int. Br. 15-19. This argument overlooks that *dried* lignite has emissions comparable to subbituminous coal. 80 Fed. Reg. at 64,574; Reconsideration Memo 21, JA4430. EPA reasonably concluded that new lignite-burning units could employ commercially available lignite-drying technology to reduce coal moisture content. As EPA explained, "Drying the lignite prior to combustion in the boiler is … an effective way to increase the thermal efficiencies and reduce the CO_2 emissions from lignite-fired power plants." 80 Fed. Reg. at 64,513 n.7 (quotation and citation omitted).

In assessing the efficiency gains of pre-drying lignite, EPA acknowledged that it was difficult to compare units in a manner that isolated the effect of the coal type from other variables. Nonetheless, EPA found that "current emission data confirm the reasonableness" of assuming comparable emissions from subbituminous- and dried lignite-burning units. Reconsideration Memo 21, JA4430. In fact, a direct comparison of similar facilities, Great River Energy's Coal Creek plant in North Dakota, which burns dried lignite, and the Colstrip unit in Montana, which burns subbituminous, shows very similar emission rates: in 2015, 2,145 and 2,100 lb-CO_2/MWh-g for the two Coal Creek units, and 2,090 and 2,115 lb-CO_2/MWh-g for the Colstrip units. In contrast, emissions from a third comparable facility in North Dakota burning virgin lignite (Antelope Valley) were "distinctly higher." Id. Given these comparisons, EPA affirmed that "the emissions from units burning sub-bituminous and dried lignite are very similar," id., and reasonably considered subbituminous and dried lignite as a single category—low rank coal—for purposes of assessing the standard's achievability.

Petitioners' accompanying contention that lignite drying is undemonstrated is also incorrect. See N.D. Br. 15; Int. Br. 17-18. Lignite drying can be accomplished through numerous available technologies identified in the record, including the DryFining technology that has been used with success at Great River Energy's Coal

Creek plant in North Dakota.[47] IEA Report 1-2, JA3846-47; Coal Memo 2-5 (listing coal upgrading and drying technologies), JA4247-50. Indeed, both the National Coal Council and the IEA Clean Coal Centre have concluded that "[c]oal drying with waste heat is a commercially available option." Reconsideration Memo 21 (emphasis omitted), JA4430; accord IEA Report 1, JA3846.

EPA also appropriately concluded that lignite-fired units will be able to install lignite drying at reasonable cost to lower their emissions. See 80 Fed. Reg. at 64,574 n.359; Int. Br. 18-19. As EPA explained, lignite drying increases the heating value of lignite (the heat released per unit burned), which in turn reduces the volume of fuel needed for generation. Coal Memo 1, JA4246; IEA Report 1, JA3846. "Drier coal is also easier to handle, convey, and pulverize—reducing the burden on the coal-handling system." Coal Memo 1, JA4246. Thus, while in 2014 IEA estimated that capital costs of lignite drying at retrofit projects were "likely to be in the range of []$33-50 million," such costs can be "largely offset" by gains in the unit's efficiency and by other operation and maintenance savings.[48] IEA Report 3, JA3848. Lignite

[47] The Coal Creek plant has two units using lignite-drying technology. While Unit 2 was retrofitted with EPAct grant funds, Unit 1 was not. International Energy Agency Clean Coal Centre, "Techno-economics of modern pre-drying technologies for lignite-fired power plants" ("IEA Report"), 2, EPA-HQ-OAR-2013-0495-11574, JA3847.

[48] For example, Coal Creek's lignite drying system costs $350,000 to operate and maintain each year, but "reduced costs by more than $20 million annually in fuel, auxiliary power consumption and other [operation and maintenance] costs." See IEA Report 2, JA3847. Even with the high "first-of-a-kind" costs to retrofit Coal Creek

(Footnote Continued …)

drying capital costs will be even lower for installations at *new* units where the drying system can be designed into the facility, because lignite drying allows for the use of a less expensive, smaller boiler. 80 Fed. Reg. at 64,537 n.123; see IEA Report 1, JA3846.

Petitioners also incorrectly suggest that EPA should have considered whether the standard was achievable using virgin, undried lignite. N.D. Br. 13-15; Int. Br. 15. As described above, however, EPA is not obligated to incorporate less efficient and more polluting means of production into its Best System. See supra Argument I.D. EPA's Best System expressly encompasses using a "highly efficient" unit, see 80 Fed. Reg. at 64,548, which for lignite-burning units includes using demonstrated lignite-drying technology to increase plant efficiency before the application of CCS.

Petitioners finally assert that EPA failed to consider the geographic limitations of lignite-burning units, which are typically sited near lignite mines. N.D. Br. 12-13. But the record shows that all six states with lignite-burning units (North Dakota, Texas, Mississippi, Louisiana, Wyoming, and Montana), see National Electric Energy Data System v5.15 Database, EPA-HQ-OAR-2013-0495-11800, JA3226-54, have widespread geologic storage potential (including via oil recovery), which covers nearly the entirety of those states. See 80 Fed. Reg. at 64,576-77 (Figure 1); Geographic Availability TSD 6-7 (showing all six lignite states in the top ten nationwide

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for lignite drying, id., this annual cost savings would recoup the cost of the retrofit well within the life of the facility.

considering DOE's minimum estimate of CO_2 storage capacity), JA2974-75. All six states also have existing CO_2 pipelines. See 80 Fed. Reg. at 64,577. In light of these facts, Petitioners' complaint that new lignite-burning units will not have access to CO_2 storage potential is implausible. Petitioners further overlook that lignite units have compliance options beyond employing CCS. See supra Argument I.A.1.b at 30.

For these reasons, EPA's appropriately found that its standard was achievable at lignite-burning units.

C. EPA Was Within Its Discretion Not to Subcategorize for Lignite-Burning Units.

EPA did not err in declining to create coal type-based subcategories. See N.D. Br. 15-18; Int. Br. 21-23. Section 111(b)(2) provides that the "Administrator *may* distinguish among classes, types, and sizes within categories of new sources." 42 U.S.C. § 7411(b)(2) (emphasis added). EPA thus has discretion to assess whether subcategories are appropriate in a given rulemaking. See Lignite Energy Council, 198 F.3d at 933 (affirming "EPA's discretion to issue uniform standards" "rather than adhering to its past practice" of subcategorizing by coal type because "EPA is not required by law to subcategorize"). Because subcategorization "involves an expert determination," a petitioner "carries a heavy burden to overcome deference to the agency's articulated rational connection between the facts found and the choices made." NRDC I, 489 F.3d at 1375 (citations omitted). Here, EPA reasonably determined that coal type-based subcategories were not "appropriate" because all units, including lignite-burning units, can meet the standard through proven, cost-reasonable means. 80 Fed. Reg. at 64,513.

Petitioners cite EPA's regulation for *existing* sources at 40 C.F.R. § 60.22(b)(5), which provides that "[the] Administrator will specify different emission guidelines … when … [such] factors *make subcategorization appropriate*" (emphasis added). See N.D. Br. 16. But that provision, which is not even applicable, likewise provides EPA with discretion to determine whether subcategorization is appropriate. See Consumer Fed'n of Am. v. HHS, 83 F.3d 1497, 1504 (D.C. Cir. 1996) (explaining that "shall, as appropriate," does not eliminate discretion).[49]

Petitioners and Intervenors also point to EPA's decision to subcategorize for lignite units in a previous rulemaking, the Mercury and Air Toxics Standards ("MATS") Rule. N.D. Br. 17; Int. Br. 21-22. EPA's determination in a previous rule addressing different pollutants does not compel it to make the same determination here. See White Stallion Energy Center, LLC v. EPA, 748 F.3d 1222, 1249-50 (D.C. Cir. 2014) (reversed on other grounds). Plus, in the MATS Rule EPA only

[49] Petitioners also claim that EPA recognized "[l]ong ago" that subcategorization would be appropriate "'[i]n most if not all cases.'" N.D. Br. 16 (quoting 40 Fed. Reg. 53,340, 53,343 (Nov. 17, 1975)). But that quote from a 1975 rulemaking preamble likewise refers to potential subcategorization of "particular classes of *existing* sources." 40 Fed. Reg. at 53,343 (emphasis added). Elsewhere in that preamble EPA expressed doubt that subcategorization would be similarly appropriate for new sources: "Thus, while there may be *only one standard of performance for new sources* of designated pollutants, there may be several emission guidelines specific for designated facilities based on plant configuration, size, and other factors *peculiar to existing facilities*." Id. at 53,341 (emphasis added).

subcategorized for lignite under the rule's *mercury* emission standard; EPA declined to subcategorize for lignite with respect to numerous other pollutants regulated under the rule.[50] EPA's decision in that rule to subcategorize lignite units for mercury emissions was compelled by the different statutory provision being implemented, which requires emissions control at the level "achieved in practice by the best controlled similar source." 42 U.S.C. § 7412(d)(3). The level of mercury emissions "achieved in practice" for lignite-burning units was higher than for other coal types, so a subcategory was warranted in that narrow circumstance. See 77 Fed. Reg. at 9387. But EPA did not subcategorize, as Petitioners claim, based on the fact that lignite-burning units are "technologically and operationally distinct … and include different design elements." N.D. Br. 17. If these general factors were enough, EPA would have subcategorized for the numerous other MATS pollutants emitted by lignite-burning units. It did not, belying Petitioners' suggestion that EPA has an "established practice" of subcategorizing for lignite. See id. 5.

A district court's decision in United States v. Minnkota Power Cooperative, Inc., 831 F. Supp. 2d 1109, 1125 (D.N.D. 2011), does not suggest otherwise. N.D. Br. 5, 9, 14, 17. In Minnkota, the court upheld North Dakota's "best available control

[50] Petitioners are incorrect that the MATS Rule set lignite-specific limits for nitrogen oxides. N.D. Br. 17 n.5. The 2011 update to performance standards for particulate matter, sulfur dioxide, and nitrogen oxides—issued along with MATS—included no subcategory or separate standard for lignite for any of these pollutants. See 77 Fed. Reg. 9304, 9453 (Feb. 16, 2012); 40 C.F.R. § 60.44Da(g)(1)(i), (g)(2)(i).

technology" determination under 42 U.S.C. § 7479 for nitrogen oxide emissions at a lignite-burning unit because there was evidence that the unique chemical composition of the unit's flue gas would "poison" the catalyst in some pollution control systems, rendering them useless. 831 F. Supp. 2d at 1115; see supra Argument I.A.2 at 42 n.21. The court's determination was thus not based on general "differences" between lignite-burning and non-lignite-burning units. 831 F. Supp. 2d at 1125-26; compare N.D. Br. 9. As Boundary Dam's performance demonstrates, CCS effectively removes CO_2 from emissions of lignite-burning units. See 80 Fed. Reg. at 64,513.

In sum, EPA reasonably exercised its discretion and declined to subcategorize for lignite-burning units where they can meet the same standard as other steam units.

D. The Rule's Treatment of Lignite-Burning Units Does Not Raise Constitutional Concerns.

Intervenors' claim that the Rule could raise "serious constitutional questions" under the Fifth Amendment, Int. Br. 23, is spurious. The Rule does not "prevent new coal-fueled [units] from being constructed" and therefore does not "deprive" Intervenors of "property, without due process of law." U.S. Const. amend. V; Int. Br. 23, 25. As explained above, new lignite-burning units can apply CCS, as Boundary Dam does already. See supra Argument I.A.1.a.i. Further, new sources may opt to use compliance alternatives like natural gas co-firing. See supra Argument I.A.1.b at 30. And regardless, existing lignite-burning units provide a market for lignite irrespective of the new facilities built. See Int. Br. 5, 8. This Court has clearly established that the constitutional avoidance canon only applies to "per se" takings. See Cellco P'ship v. FCC, 700 F.3d 534, 549 (D.C. Cir. 2012). Because the record here demonstrates that lignite units can install CCS technology that will allow them to meet the standard (as demonstrated by Boundary Dam), there is no per se taking and the constitutional avoidance canon is inapplicable.

Ultimately, Intervenors invoke the constitutional avoidance canon not to save the Rule from unconstitutionality but to put a thumb on the scale in favor of their other arguments. Either this Court will conclude that EPA's record supports a conclusion that CCS is adequately demonstrated, in which case Intervenors' assertion that their members will be unable to build new steam units will have no force; or this Court will conclude that CCS is not adequately demonstrated, in which case the Rule is arbitrary and capricious and the Court need not reach constitutional objections. Thus, Intervenors' insinuation of possible constitutional concerns has no import except to press this Court to abandon its longstanding practice of deferring to expert agencies. Int. Br. 25 ("[T]he agency's construction should be rejected, without deference, in favor of one that will not cause a taking."). This invocation of the constitutional avoidance canon is contrary to its purpose, which is to address "grave and doubtful constitutional questions," not to allow for "disingenuous evasion" of Congressional intent. Rust v. Sullivan, 500 U.S. 173, 191 (1991) (quotations omitted).

III. EPA'S STANDARDS FOR MODIFIED AND RECONSTRUCTED STEAM UNITS SHOULD ALSO BE UPHELD.

EPA reasonably established standards of performance for modified and reconstructed units based on the levels of performance already achieved and the technologies and practices steam units already use. Consequently, Petitioners' arguments should be rejected and EPA's standards should be upheld.

A. EPA's Modification Standard Is Achievable Because It Conforms To Performance Levels Units Have Already Achieved.

EPA's modification standard is limited to "large" modifications, defined as a "physical or operational change" that increases a steam unit's hourly CO_2 emissions by more than 10 percent compared to its previous five-year high. 80 Fed. Reg. at 64,597. Few large modifications have been reported historically; given this scarcity of examples, and the diversity of existing steam units, EPA declined to establish a one-size-fits-all modification standard. Id. Instead, a modifying unit must meet its best historical emissions performance, considering average annual performance since 2002. Id. at 64,512 (Table 1). In addition, no facility—regardless of its historical performance—is required to meet a standard more stringent than the standard for reconstructed facilities. Id.

Petitioners argue that EPA's standard is not achievable because there is no evidence that a unit can replicate its best past performance on a continuous basis across the "range of relevant conditions." Non-State Br. 57 (citing Nat'l Lime, 627

F.2d at 433); see id. 55-56.[51] But EPA's standard for a given unit is, *by definition*, a level of performance that has already been achieved by that unit on a continuous basis. EPA's plant-by-plant modification standard considers the unit's performance over a full year; it therefore reflects what is achievable, on average, over an entire year's worth of seasonal, operational, and other variability—including changes in ambient temperature and in the unit's capacity factor. See 80 Fed. Reg. at 64,573; Response to Comments for Modified and Reconstructed EGUs ("Mod-Recon RTC") – Chapter 6, 6.2-31, 6.2-32, EPA-HQ-OAR-2013-0603-0307, JA4377, JA4380-81. Moreover, this Court has explained that the modification standard "need not … be routinely achieved within the industry prior to its adoption." Essex, 486 F.2d at 434. Instead, EPA must ensure that the standard is "within the realm of the adequately demonstrated system's efficiency" and "not at a level that is purely theoretical or experimental." Id. at 433-34. The performance level a unit has *already* achieved and maintained for a full 12-month period is demonstrably "within the realm" of the unit's capabilities and is not "purely theoretical or experimental." Accordingly, EPA reasonably determined that facilities making large modifications could achieve this unit-specific historical standard.

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[51] Petitioners' claim that EPA did not explicitly find the standard "achievable," Non-State Br. 55, is merely semantic. See 80 Fed. Reg. at 64,514 (determining that the standard "can be met" through the Best System). Their argument that EPA did not address the "adequate demonstration" criteria, Non-State Br. 56, is refuted by EPA's discussion of cost and other factors. See 80 Fed. Reg. at 64,599-600.

Furthermore, the modification standard is only triggered for "large modifications," 80 Fed. Reg. at 64,597, a category intended to capture "major facility upgrades" like "the refurbishing or replacement of steam turbines." Id. at 64,598. When a unit makes such significant changes, it likewise has an opportunity to apply the technological or operational adjustments needed to meet the efficiency level it achieved previously. See Mod-Recon RTC 6.2-8, JA4358-59; see generally U.S. DOE Information on Technical Basis for "Large Modification" Threshold (describing previous modifications), EPA-HQ-OAR-2013-0495-11789, JA3255-79. To that end, EPA provided an analysis of the broad range of efficiency measures available to existing sources. See 80 Fed. Reg. at 64,599 (incorporating Clean Power Plan efficiency analysis); CPP Mitigation TSD 2-11–2-15 (listing equipment upgrades and best practices), 2-16–2-22 (summarizing extensive technical literature on widely applicable, cost-effective efficiency upgrades), JA3001-05, JA3006-12. While EPA notes not every measure identified would be available at every facility, id. 2-10, JA3000; see Non-State Br. 56, EPA found when considering this analysis in the Clean Power Plan that given EPA's "conservative" methodology, the "full range of best practices and equipment upgrades available" to individual units would very likely provide more efficiency opportunities than accounted for by the Agency. 80 Fed. Reg. at 64,793. EPA thus reasonably determined that the breadth of available tools would be sufficient, as the standard is already particularized to each unit's capabilities. See Mod-Recon RTC 6.1-25, JA4327.

In any event, Petitioner's assertion that some units may be unable to meet their best historical emissions performance—whether because of changing capacity factors or degradation over time—is immaterial. See Non-State Br. 57. By keeping any increase in their *current* emissions below the applicable threshold, units planning physical or operational changes have significant latitude to avoid triggering the modification standard. This could be accomplished by, for example, co-firing a unit's boiler with a small amount of natural gas, which is a well-demonstrated and widely available emission reduction technology. See, e.g., 80 Fed. Reg. at 64,564-65; Mod-Recon RTC 6.1-7, 6.1-20, JA4316, JA4324.

As this Court held in Portland Cement III, a modification standard is demonstrated and achievable even where some facilities cannot meet the standard, provided those facilities "could avoid increasing their … emissions—and thus, remain in compliance with [new source performance] standards" through alternative controls. 665 F.3d at 190; see also ASARCO, Inc. v. EPA, 578 F.2d 319, 328-29 (D.C. Cir. 1978). EPA's modification standard is thus achievable across the source category, whether because a particular unit can meet its own historical performance level, or because it can take incremental steps to keep its emissions from increasing beyond the modification threshold. Accordingly, EPA's standard should be upheld.

B. EPA's Reconstructed Source Standard Is Demonstrated and Achievable.

In establishing a standard for large and small reconstructed steam units, EPA looked to the performance of "the most efficient generation technology available" applied to a "well operated and maintained [unit]." 80 Fed. Reg. at 64,600. This Best System is adequately demonstrated because it reflects technologies and practices currently used in the industry and that may realistically be applied when a facility makes the significant capital expenditures that define a reconstruction. In addition, EPA demonstrated that the selected standard is achievable across a range of industry conditions. Finally, because the reconstruction standard is only triggered where it is feasible, Petitioners' objections are unavailing.

To establish the standard, EPA first identified the large and small units employing the most efficient operation and maintenance practices. See Reconstruction Coal-Fired BSER Memo ("Reconstruction Memo"), 7-12, EPA-HQ-OAR-2013-0603-0046, JA4240-45. While EPA does not possess *direct* information regarding individual units' operation and maintenance practices, see id. 7, JA4240; Non-State Br. 62, the efficiency gains attributable to these practices can be discerned by analyzing monitoring data submitted by the units and then "normalizing" that data to control for all other variables (like technology, capacity factor, and location). For example, data from a unit operating in colder conditions would be mathematically normalized to indicate how that unit would operate in warmer conditions.

Reconstruction Memo 7, JA4240. This allowed EPA to make an apples-to-apples comparison of the effects of operating practices across units, and to select the "best performing" large and small units: the Weston 4 and Wygen III units, respectively. Id. 8, JA4241.

After identifying the best performing units, EPA further adjusted these units' emissions data to reflect the improvement each facility would see if it reconstructed to install the most efficient generating technology—applying proven metrics about steam temperatures and pressures achieved by technologies already on the market. Id. 7-12, JA4240-45. As Figures 5 and 7 of the Reconstruction Memo show, EPA considered these units' optimized performance using six different coal types and four technological combinations. Id. 9, 11, JA4242, JA4244. This data confirmed that large units employing best operating practices and efficient technology can meet a standard of performance of 1,800 lb-CO_2/MWh-g—even using lignite—and that small units can meet a standard of performance of 2,000 lb-CO_2/MWh-g. See id. 10-11 (Figures 6, 8), JA4243-44.[52]

Petitioners argue that EPA's Best System is not adequately demonstrated because EPA has not shown that any facility has made these technological changes in practice. Non-State Br. 58-59. In particular, Petitioners contend that EPA has not

[52] The Reconstruction Memo was published at proposal, so it references proposed emission rates of 1,900 and 2,200 lb-CO_2/MWh-g. However, Figures 6 and 8 demonstrate that the final rates are also achievable. See also 80 Fed. Reg. at 64,600.

shown that "subcritical" boilers, which operate with lower steam temperatures and pressures, can be "completely rebuilt" to handle higher "supercritical" steam temperatures and pressures. Id. 59. But Petitioners overlook the fact that an existing facility only becomes subject to the reconstruction standard if "[t]he fixed capital cost of the [facility's] new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." 40 C.F.R. § 60.15(b)(1) (defining "reconstruction"); see 80 Fed. Reg. at 64,527. As an initial matter, this "significant economic hurdle" makes reconstruction exceedingly rare, so *any* standard the Agency set would be unlikely to reflect practical examples from reconstructing units. See Mod-Recon RTC – Chapter 5, 5.1-1, 5.1-2, EPA-HQ-OAR-2013-0603-0306, JA4271, JA4272-73; Mod-Recon RTC 6.1-21, JA4324.

Moreover, where a facility makes a large, one-time capital expenditure sufficient to trigger the reconstruction standard, it is reasonable to expect that it has the opportunity to make significant technological improvements. See id. 6.1-21 (noting that reconstruction requires a "single reconstruction investment" rather than "cumulative expenses"), JA4324. Considering the cost of new steam units, 80 Fed. Reg. at 64,560 (Table 7), the capital expenditures necessary to trigger the reconstruction standard would likely be in the range of 100-700 million dollars. EPA therefore concluded that reconstructions would not be "smaller projects" undertaken "as a means of improving efficiency or heat rate or to prolong the operating life of a unit," Mod-Recon RTC 5.2-10, JA4287, but would rather consist of "considerable investment in (if not entire replacement of) the boiler," id. 5.2-8, JA4285. Under such circumstances, EPA reasonably concluded that reconstructing facilities will be able to apply efficient boiler technologies currently used within the industry.

Petitioners also argue that EPA's standards are not achievable because the two "best performing" units were unrepresentative of the broader industry, and because EPA set standards "more stringent than what the[] 'best performing facilities' achieved without providing any basis for doing so." Non-State Br. 61; see id. 60-62. Petitioners' protests that the two "best performing facilities" are relatively new, burn subbituminous coal (rather than lignite), and operate at relatively high capacity factors are inapposite. Non-State Br. 61. As described above, EPA's assessment was based on "normalized" plant data—not the particularities of either Weston 4 or Wygen III. EPA conservatively assumed that reconstructing units would be located in warm areas (since colder temperatures improve efficiency), Reconstruction Memo 4, 7, JA4237, JA4240, and specifically considered achievability with different coal types, including lignite. See id. 9-11 (Figures 5-8), JA4242-44. EPA logically relied on a relatively high capacity factor to reflect that a facility investing potentially hundreds of millions of dollars in new components would likely expect to recoup that investment through frequent operation. And EPA did not err in using data from "relatively new" units; units rebuilt in the future will be equally well-positioned as those built in 2008 and 2010 to ensure efficient operation.

Likewise, EPA employed a sound technical methodology to isolate and apply the efficiency gains from both optimal operational protocols, as evidenced by the performance of existing facilities, and the installation of advanced boiler technology, which Petitioners admit is already in use. See Non-State Br. 59. This methodology optimized the performance of the two best "operated and maintained" units across a range of technologies and coal types, illustrating the standard's broad achievability. See Reconstruction Memo 10-11 (Figures 6, 8), JA4243-44. The fact that existing facilities have not yet opted to rebuild their facilities in this manner is not evidence otherwise: as the regulatory threshold and historical record suggest, rebuilding a facility is a rare and expensive undertaking. The reconstruction standard applies where a facility decides to rebuild, but no facility is compelled to do so.

Finally, and significantly, Petitioners overlook the regulatory definition of "reconstruction," which is limited to those instances where "[i]t is technologically and economically feasible to meet the applicable standards set forth in this part." 40 C.F.R. § 60.15(b)(2). As discussed above, the record shows that the reconstruction standards are achievable. But in the unlikely event a particular unit could show that the applicable standard was infeasible—whether, for example, because the original boiler design could not withstand higher temperatures and pressures, or because it would be prohibitively expensive—and the unit had no other compliance options, that unit would not trigger the standard. See 80 Fed. Reg. at 64,601; Mod-Recon RTC 5.1-2, JA4272-73.

Accordingly, EPA's reconstruction standard should be upheld.

IV. EPA GAVE APPROPRIATE CONSIDERATION TO CCS FOR BOTH STEAM UNITS AND COMBUSTION TURBINES AND REASONABLY EXPLAINED ITS DIFFERING CONCLUSIONS.

Petitioners' assertion that EPA was unjustified in selecting partial CCS as the Best System for newly constructed steam units while rejecting it for newly constructed combustion turbines is contrary to the record. EPA may treat source categories differently as long as it provides a "coherent explanation" for doing so. See Non-State Br. 48; Airmark Corp. v. FAA, 758 F.2d 685, 687 (D.C. Cir. 1985). Here, EPA thoroughly explained why applying the statutory factors to combustion turbines and steam units led to different outcomes—in particular, because CCS is not yet adequately demonstrated for combustion turbines that cycle and change load more quickly and frequently than steam units.

As explained in Argument I.A, CCS is adequately demonstrated for steam units, which primarily provide uninterrupted power. See 80 Fed. Reg. at 64,573. Combustion turbines, on the other hand, can start up, shut down, and change load more quickly than steam units, making them more suited to serving variable power demand. Id. at 64,609. Consequently, combustion turbines are operated with much greater flexibility—both across the source category and over the life of a single unit. Id. For example, a particular unit may cycle on and off with changes in electricity demand in winter, but provide steady, uninterrupted power in summer. Id. Likewise, two units "may have similar electric sales, but very different operating characteristics," because "one unit might have relatively steady operation for a short period of time, while another could have variable operation throughout the entire year." Id. Finally, while large, efficient combined-cycle units are most likely to operate continuously at high load, and small, fast-starting simple-cycle units are most likely to operate only in times of peak demand, the source category also includes high-efficiency simple-cycle units and newer "fast-start" combined-cycle units that blur these lines—both of which are expected to see increased deployment as back-up for renewable energy sources. Id. at 64,610. To account for this diversity, EPA established two subcategories of combustion turbines, "baseload" and "non-baseload" units, grouping as "baseload" units those units that sell substantial amounts of power to the grid on an annual basis, whether they serve steadier or more variable load.[53] Id. at 64,608-10 (describing subcategorization).

EPA reasonably considered the flexible operation of combustion turbines when assessing whether partial CCS was adequately demonstrated for these units. In particular, EPA determined that partial CCS was not adequately demonstrated for combustion turbines because some units can "start and stop multiple times in a single day and can ramp to full load in less than an hour." Id. at 64,614. EPA explained that it was unaware of "any pilot-scale CCS projects that have demonstrated how fast

[53] For reasons explained in the Rule, and not challenged here, EPA concluded that it was not appropriate to subcategorize based on unit size, which is weakly correlated with CO_2 emissions, or technology type, which raises difficult questions related to high-efficiency simple-cycle and fast-start combined-cycle units. Id. at 64,608-09.

and frequent starts, stops, and cycling will impact the efficiency and reliability of CCS [for combustion turbines]." Id. EPA further explained that for combustion turbines that quickly cycle on and off, "the CCS system might not have sufficient time to startup" before the unit comes online, meaning "no CO_2 control would occur" during that period. Id. If this were the case, the unit's operator would have to install a larger CCS system to "make up for those periods when no control is achieved by the CCS." Id. This concern does not apply to steam units because they "take multiple hours to start and ramp relatively slowly." Id. Accordingly, EPA reasonably determined that partial CCS was not adequately demonstrated for the full range of combustion turbines in the "baseload" subcategory.

In response, Petitioners contend that the evidence supporting the feasibility of CCS for combustion turbines is as robust as that supporting the feasibility of CCS for steam units. Petitioners point to a plant in Massachusetts, which stopped capturing CO_2 in 2005, and a plant in Japan as two examples of combustion turbines that successfully applied CCS technology. Non-State Br. 49. They compare the experience at these plants to Boundary Dam and other record evidence of CCS being applied at steam units,[54] arguing that if the former is insufficient evidence that CCS is adequately demonstrated for combustion turbines, the latter is insufficient evidence

[54] Petitioners' wrongly assert that EPA made "incorrect[]" claims about CCS projects under development. Non-State Br. 52; see 80 Fed. Reg. at 64,549-52 (describing CCS projects at U.S. steam units), 64,613 (describing the very preliminary planning of the proposed combustion-turbine CCS project).

for EPA's determination for steam units. Non-State Br. 49. But EPA did not conclude that partial CCS was inadequately demonstrated for combustion turbines because too few plants had installed the technology. Rather, EPA concluded that Petitioners' examples were only sufficient to show that CCS could be applied to combustion turbines operating in limited conditions. See 80 Fed. Reg. at 64,614. The facilities in Massachusetts and Japan, as well as two conceptual plants under consideration in Texas and Scotland, were designed and operated to provide uninterrupted baseload power. As such, none demonstrated how CCS would operate at plants serving variable load. Id. By contrast, Boundary Dam and the additional plants discussed in Argument I.A.1.a, supra, provided ample evidence that partial CCS is adequately demonstrated for the steam-unit source category as a whole.

Petitioners also contend that even if partial CCS is not adequately demonstrated for "intermediate units that cycle more frequently," EPA cannot treat "true baseload" combustion turbines and steam units differently. Non-State Br. 50-51. Petitioners' framing is overly simplistic. As the Rule explains, there are no clear lines distinguishing "true baseload" units from "intermediate" units (or "intermediate" units from "load following" and "cycling" units). 80 Fed. Reg. at 64,609. While the design efficiency or cycling speed of a unit may make it more likely to be used in one manner or another, the operational flexibility inherent to combustion turbines means that a single unit might change its operating profile over the course of a year or from year to year—operating at times like a steam unit, with "near-steady, high loads," and at other times "continuously [but] with variable loads."[55] 80 Fed. Reg. at 64,609. Petitioners' suggestion that EPA should have considered only those units operating as "true baseload units" in assessing the Best System thus fails to account for the variability that is inherent in the source category itself.

Petitioners further argue that EPA failed to consider that "some [steam] units cycle more frequently than others and that some even cycle as frequently as those [combustion turbines] the Agency considered to be an intermediate unit." Non-State Br. 51. Petitioners point to no record evidence supporting this assertion. While low gas prices may have prompted some existing steam units to operate less in recent years, steam units still require a longer period to shut down and start up again. 80 Fed. Reg. at 64,614. Consequently, "intermediate" steam units would be expected to operate during extended periods of high demand, like the winter and summer months, but would not cycle the way combustion turbines do. Furthermore, EPA found that a new steam unit "would, most likely, be built to serve [baseload] power demand exclusively and would not be expected to routinely startup, shutdown, or ramp its capacity factor in order to follow load demand." Id. at 64,614 n.535; see id. at 64,573. By contrast, some combustion turbines are specifically designed for that purpose, and EPA reasonably concluded that such turbines may operate frequently enough to be

[55] EPA's determination in the Clean Power Plan that existing combined-cycle turbines are likely to operate at higher loads in the future is irrelevant; the operation of such units in no way constrains the operating flexibility of new combustion turbines, which are not subject to the Clean Power Plan. See Non-State Br. 51 n.19.

placed in the "baseload" subcategory. See, e.g., id. at 64,614 (discussing "fast-start [combined-cycle] units that sell more than 50 percent of their potential output to the grid").

None of Petitioners' other arguments are availing. Because EPA determined that partial CCS was not adequately demonstrated for "baseload" combustion turbines, it is irrelevant whether the costs of partial CCS for such units compare favorably to the costs of partial CCS for steam units, or whether EPA chose a "technology-forcing" system for one source category but a "business-as-usual" system for the other. See Non-State Br. 53. Nor did EPA seek to improperly influence the energy market when it required each source category to use the best pollution control system available to it. See id. 48, 54-55. For each source category, EPA applied the statutory factors and those factors—not an alleged "policy agenda"—drove the outcome.[56]

Finally, EPA's detailed analysis of its decision, covering nearly nine pages in the Federal Register, belies Petitioners' claim that EPA provided a "barebones incantation of … abbreviated rationales" for its conclusion that partial CCS is adequately demonstrated for steam units, but not for combustion turbines. See 80 Fed. Reg. at

[56] Nor is EPA's treatment of new steam units inconsistent with its treatment of combustion turbine modifications. See Non-State Br. 54 n.20. While few combustion turbine modifications are expected, EPA explained its independent rationale for declining to set a standard for those modifications. See 80 Fed. Reg. at 64,621-22.

64,608-16. EPA reasonably and thoroughly explained the reason for the different outcomes, so its determinations should be upheld. In any event, as described in Argument I.A, the record demonstrates that partial CCS is adequately demonstrated for steam units and that EPA reasonably adopted partial CCS as part of the Best System for that source category. Consequently, were the Court to conclude that EPA erred in deciding not to require the same technology for combustion turbines, the proper remedy would be to remand the standard for "baseload" combustion turbines to the Agency for further proceedings, not to remand or vacate the independently-supported standard for steam units.

V. A NEW ENDANGERMENT FINDING WAS NOT REQUIRED HERE, BUT IN ANY CASE, THE RECORD CONSTITUTES SUCH A FINDING.

EPA's regulation of CO_2 from its largest emitter, fossil-fuel-fired power plants, fully complied with Section 111(b)(1). Having already found these sources to be significant contributors to air pollution that endangers public health and welfare and having already listed them pursuant to Section 111(b)(1)(A), see supra Statement of the Case II.B, EPA was not required to promulgate another endangerment finding before regulating their CO_2 emissions. Petitioners' assertion that Section 111(b)(1)(A) requires a new endangerment finding every time EPA issues a performance standard for a new pollutant under Section 111(b)(1)(B) is contrary to the statute's structure and plain language. Even if the statute required a new endangerment finding, EPA's thorough documentation of harm attributable to power plant CO_2 emissions constitutes that finding.

A. Section 111(b) Only Requires an Endangerment Finding When a Source Is First Listed, Not Every Time Standards of Performance Are Promulgated.

Section 111(b) establishes a two-step process for regulating emissions from new sources. As previously described, see supra Statement of the Case I.A, Section 111(b)(1)(A) requires EPA to list source categories for potential regulation pursuant to an endangerment finding. 42 U.S.C. § 7411(b)(1)(A). Thereafter, EPA regulates particular pollutants under Section 111(b)(1)(B), which sets no criteria for what pollutants EPA should regulate, but rather leaves an implicit delegation to the Administrator to publish and promulgate appropriate "standards of performance" for the listed source category. See id.; 80 Fed. Reg. at 64,530.

EPA listed the steam unit and combustion turbine source categories under Section 111(b)(1)(A) in the 1970s. See supra Statement of the Case II.B. Pursuant to its authority under Section 111(b)(1)(B), EPA has now established additional standards of performance for these source categories for CO_2. Because both source categories were previously listed, no listing under Section 111(b)(1)(A)—and thus no endangerment finding—is required. See 42 U.S.C. § 7411(b)(1)(A); 80 Fed. Reg. at 64,529. EPA need only demonstrate, consistent with the delegation of authority in Section 111(b)(1)(B), that it has acted reasonably (with a "rational basis") in setting additional "standards of performance for new sources within such categor[ies]." See 42 U.S.C. § 7411(b)(1)(B).

Petitioners' claim that promulgation of new performance standards requires a new endangerment finding (specific to CO_2 from fossil-fuel-fired power plants) fails. Petitioners read words into the statute that it does not contain, paraphrasing Section 111(b)(1)(A) as requiring a finding that "the *specific* 'air pollution' *to be regulated*" endangers health and welfare, and that the source category "'causes, or contributes significantly to' *that* endangering air pollution." Non-State Br. 63 (emphasis added); see State Br. 34 ("EPA must find that *the air pollutant it seeks to regulate* 'may reasonably be anticipated to endanger …'" (emphasis added)). But Section 111 does not include these words, nor does it necessitate Petitioners' reading.

State Petitioners' sole textual support for their reading is that "the endangerment requirement modifies, and relates back to, 'air pollution,' not 'sources.'" State Br. 35. While it is true that the endangerment finding considers whether the source category contributes to "air pollution which may … endanger," such a finding is for the sole purpose of determining whether the *source category* should be listed. See 42 U.S.C. § 7411(b)(1)(A) ("The Administrator shall … publish … a list of categories of stationary sources. [She] shall include a category of sources in such list if in [her] judgment it causes…"). The endangerment finding is therefore a determination as to which "categories" of stationary sources should be listed, not a direction to list specific pollutants. Only after listing does EPA consider appropriate standards of performance under Section 111(b)(1)(B), and that subsection sets no criteria for determining *which* particular pollutants emitted by a listed source category may be regulated. That is a gap left to EPA's reasoned discretion.[57]

Non-State Petitioners take a different tack, attempting to justify their reading by resort to the definition of "standard of performance" in Section 111(a)(1). A standard of performance, they say, "is, by definition, tied to specific pollutants for which an endangerment finding has been made" because that definition uses the phrase '"a standard for emissions of *air pollutants*."' Non-State Br. 65. But the fact that EPA must set standards of performance with respect to individual pollutants under Section 111(b)(1)(B) does not tell us anything about which pollutants it may regulate, and certainly does not require "by definition" that those pollutants have been singled out in the original endangerment finding under Section 111(b)(1)(A). Indeed,

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[57] This is reflected in previous Section 111(b) rulemakings. See, e.g., 73 Fed. Reg. 35,838, 35,858 (June 24, 2008) ("The Agency has always interpreted [the requirement to establish standards of performance] as providing the Administrator with significant flexibility in determining which pollutants are appropriate for regulation under [S]ection 111(b)(1)(B)."); Portland Cement III, 665 F.3d at 193 (noting that EPA had not yet issued a Section 111(b) standard for greenhouse gases from cement kilns because it "decided its data was insufficient"); Nat'l Lime, 627 F.2d at 426 (acknowledging that "[a]lthough lime plants were determined to be sources of nitrogen oxides, carbon monoxide and sulfur dioxide as well as particulates, standards of performance [under Section 111(b)(1)(B)] were proposed and ultimately promulgated only with respect to particulate matter").

EPA's endangerment finding for steam units did not identify *any* individual pollutants whatsoever.[58] 36 Fed. Reg. at 5931.

Frustrated by the plain text, non-State Petitioners next contend that Congressional intent is discernible from *other* sections in the Act with pollutant-specific endangerment findings and from legislative history they say shows Congress viewed these endangerment findings as "standardized" across sections. Non-State Br. 65-66. And both groups of Petitioners claim that Congress must have intended EPA to make a new endangerment finding for each pollutant because anything else would give EPA a "blank check" to regulate anything it wished. See Non-State Br. 64; State Br. 35. Petitioners' assertions are unpersuasive, as neither the comparison to other CAA provisions nor the cited legislative history evinces a hidden Congressional intent to require EPA to assess the appropriateness of regulation in the context of an endangerment finding.

First, Petitioners' contextual arguments fail. The statutory provisions Petitioners cite, Sections 202(a)(1), 211(c)(1), and 231(a)(2)(A), share a common textual structure—one that Section 111 notably lacks. Compare 42 U.S.C. §§ 7521(a)(1), 7545(c)(1), 7571(a)(2)(A), with id. § 7411(b)(1)(A)-(B); see Non-State Br. 65. While all three provisions require, as Section 111 does, that EPA make endangerment and cause-or-contribute determinations, they require those findings as

[58] Thus, under Petitioners' logic, *all* of the numerous previous rulemakings establishing standards of performance for steam units were defective.

part of the grant of authority to EPA to promulgate specific regulations for specific pollutants (or, in Section 211, for specific fuels or fuel additives). Section 231(a)(2)(A) shows this common feature:

> The Administrator shall, from time to time, issue proposed emission standards applicable to the emission of any air pollutant from any class or classes of aircraft engines which in his judgment causes, or contributes to, air pollution which may reasonably be anticipated to endanger public health or welfare.

42 U.S.C. § 7571(a)(2)(A). As in the other two sections cited by Petitioners, EPA's authority in Section 231 is to *promulgate particular standards for particular air pollutants*, and it is the exercise of that specific, case-by-case authority that requires an endangerment finding. Section 111(b)(1)(A), by contrast, does not provide the authority to issue pollution control regulations. It provides EPA with the authority to *publish a list of source categories*, and for that purpose alone, EPA is required to make an endangerment finding. See 42 U.S.C. § 7411(b)(1)(A); 80 Fed. Reg. at 64,530. EPA's authority to set standards of performance after a source category is listed is conveyed by Section 111(b)(1)(B), which does not require EPA to make any additional finding.

Petitioners' cited legislative history, Non-State Br. 66, does not negate this textual distinction. The 1977 House Report's description of "standardized" provisions was particular to the phrasing "'which in his judgment cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare.'" H.R. Rep. 95-294, at 50 (1977), reprinted in 1977 U.S.C.C.A.N. at 1128, JA4606. The Report, however, was describing the application of "[t]his same basic formula" in the 1977 CAA Amendments, id.; Section 111 was adopted in 1970, and already established the two-step framework for listing sources (pursuant to an endangerment finding), followed separately and thereafter by promulgation of standards. Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1684 (1970). The 1977 amendment to "standardize" language across the Act made two changes to the existing text of Section 111: (1) replacing "if he determines it may contribute" with "if in his judgment it causes, or contributes"; and (2) replacing "air pollution which cause or contributes to the endangerment of" with "air pollution which may reasonably be anticipated to endanger." Compare id. with 42 U.S.C. § 7411(b)(1)(A). Neither change altered the feature unique to Section 111: that EPA makes its endangerment finding with respect to a "category of sources" in the context of listing that category, not as part of subsequent regulation of specific pollutants from that category.[59]

Second, reading Section 111(b) to require an endangerment finding for listing a source category, but not for promulgating a performance standard, does not give EPA "unfettered authority" or allow it to regulate some pollutants under a lower threshold

[59] Petitioners' reference to the 2009 Endangerment Finding, Non-State Br. 66, is inapposite. There, EPA was responding to commenters asserting that EPA's endangerment finding had to assess "how effective the resulting emissions control standards will be." 74 Fed. Reg. at 66,507. In explaining that endangerment findings do not include such a showing, EPA noted the "broad similarity in the phrasing of the endangerment and contribution decision" across CAA provisions, notwithstanding the varying thresholds for regulation thereafter. EPA did not speak to when such endangerment findings are necessary.

than others. See Non-State Br. 64-65; State Br. 35-36. There is no text in Section 111(b) that calls for an endangerment finding before regulating pollutants from listed source categories. But this does not absolve EPA of the need to persuasively demonstrate the appropriateness of regulating a particular pollutant from a particular source category. See Motor & Equip. Mfrs. Ass'n, Inc. v. EPA, 627 F.2d 1095, 1106 (D.C. Cir. 1979) ("The Administrator must give reasoned consideration to the issues before [her] and reach a result which rationally flows from this consideration."). Here, EPA explained at length its understanding of CO_2's contribution to environmental and other harms, identified and compared the source category's emissions to other sources of CO_2, and "articulated a 'rational connection between the facts found and the choice made.'" ADX Commc'ns of Pensacola v. FCC, 794 F.3d 74, 79 (D.C. Cir. 2015) (quoting Motor Vehicle Mfrs. Ass'n, 463 U.S. at 43); see infra Argument V.B; State Br. 36. This is precisely the analysis Petitioners demand. Petitioners' insinuation that EPA would seek to regulate an "air pollutant emitted by [a] source regardless of whether it endangers health or welfare," and go beyond the bounds of "reasoned decisionmaking," see Non-State Br. 65, would not only fail rational-basis review, it is entirely divorced from the findings the Agency actually made in establishing the Rule.

Finally, the Act does not establish different thresholds for initial and subsequent standards of performance promulgated under Section 111(b)(1)(B). See State Br. 36. In each case, EPA must show that it had a rational basis to promulgate a standard of performance. The fact that EPA's decision to list a source category under Section 111(b)(1)(A)—which is a separate agency action—can itself be challenged, or that such a challenge might occur alongside a challenge to the first set of performance standards for particular pollutants, does not mean that EPA must meet a different threshold when promulgating future standards.

In summary, Petitioners' reading is inconsistent with the plain text of Section 111 and not mandated by either context or logic. Because steam units and combustion turbines are already listed under Section 111(b)(1)(A), EPA was not required to make a new endangerment finding before promulgating standards for their CO_2 emissions under Section 111(b)(1)(B).

B. Were a New Endangerment Finding Required, EPA's Record Would Constitute That Finding.

Even if Petitioners were correct, however, and EPA were required to find that carbon dioxide is "air pollution which may reasonably be anticipated to endanger public health or welfare," EPA made and abundantly substantiated those findings here. The Rule incorporates the extensive scientific material that supported EPA's 2009 Endangerment Finding, which concluded that mobile source emissions of greenhouse gases endanger public health or welfare. See 80 Fed. Reg. at 64,517, 64,530-31; cf. Coalition for Responsible Regulation, Inc. v. EPA, 684 F.3d 102, 120 (D.C. Cir. 2012) (reversed, in part, on other grounds) ("The body of scientific evidence marshaled by EPA in support of the [2009] Endangerment Finding is substantial."). To this foundation, EPA added recent scientific assessments regarding CO_2's contribution to climate change, and climate change's impacts on public health and welfare. 80 Fed. Reg. at 64,517-24. As EPA explained, since 2009, "a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that [greenhouse gases] endanger public health and welfare both for current and future generations." Id. at 64,517.

Likewise, EPA's "cause-or-contribute" assessment relies on three tables comparing U.S. emissions data, which show that "[f]ossil fuel-fired [units] are by far the largest emitters of [greenhouse gases] among stationary sources in the U.S., primarily in the form of CO_2." Id. at 64,522-23 (Tables 3-5). As these tables demonstrate, fossil-fuel-fired power plants "are responsible for almost three times as much [greenhouse gas pollution] as the emissions from the next ten stationary source categories combined." Id. at 64,531. Furthermore, the record establishes that emissions from combustion turbines and steam units "far exceed in magnitude the emissions from motor vehicles, which have already been held to contribute to the endangerment" attributable to greenhouse cases. Id. (citing Coalition for Responsible Regulation). EPA thus concluded that "the information and conclusions described [in the Rule] should be considered to constitute the requisite [endangers-public-health-and-welfare] finding" and "cause-or-contribute significantly finding." Id. at 64,530.

Petitioners charge that the literature EPA cites is "too general and outdated" to support an endangerment finding and that EPA did not specify which "information and conclusions" it relied on. Non-State Br. 68. These are not credible objections. Among others, EPA discussed the conclusions of both the 800-page 2014 National Climate Estimate: Climate Change Impacts in the United States, and the several-thousand-page Intergovernmental Panel on Climate Change's 2013-2014 Fifth Assessment Report. 80 Fed. Reg. at 64,517-22. EPA also relied on the most recent published emission data. Id. at 64,523 nn.37, 42, 43 (2013 data, published in 2014-15). And the Rule does not hide EPA's assessments, which appear in sections entitled "Climate Change Impacts From GHG Emissions," id. at 64,517, and "GHG Emissions From Fossil Fuel-Fired EGUs," id. at 64,522. Indeed, EPA specified precisely which reports and information were the primary basis for "both the endangerment finding and the rational basis" undergirding the Rule. Id. at 64,530-31.

Nor is this evidence undermined, as Petitioners assert, by the record's reference to both greenhouse gases and CO_2. Petitioners claim both that EPA cannot rely on its 2009 Endangerment Finding, as that finding was "about a different air pollutant," Non-State Br. 67, and that EPA's record cannot constitute an endangerment finding because it "does not focus on CO_2 alone," id. 68. First, "EPA is not relying on the 2009 [E]ndangerment [F]inding to be an endangerment finding for this rule." Mod-Recon RTC – Chapter 2, 2.2-22, EPA-HQ-OAR-2013-0495-11816, JA4261. Rather, the Rule adopts the "information and analysis" included in the 2009 Finding as part of its examination of the science underpinning the Rule. Id.; see 80 Fed. Reg. at 64,530 (justifying the Rule as based on "*analysis and conclusions* in the EPA's 2009

Endangerment Finding" coupled with subsequent scientific assessments (emphasis added)).

Second, "the air pollutant regulated in this rule is [greenhouse gases]," notwithstanding that the standards address CO_2.[60] 80 Fed. Reg. at 64,537; see id. at 64,531 n.110 ("[T]here is, of course, no requirement that standards of performance address each component of the air pollution which endangers"). The same was true in 2009, when EPA's Endangerment Finding covered six greenhouse gases but where EPA's vehicle rule set standards for only four. 75 Fed. Reg. 25,324, 25,397-98 (May 7, 2010); cf. Am. Trucking Ass'ns v. EPA, 175 F.3d 1027, 1055 (D.C. Cir. 1999) (holding that an EPA rule for $PM_{2.5}$ was not regulating a "new pollutant" because prior rules for PM_{10} encompassed $PM_{2.5}$) (reversed on other grounds).

Finally, Petitioners' assertion, Non-State Br. 68, that the gravity of the evidence should be ignored because "climate change is a complex phenomenon" is risible, and was foreclosed by this Court in Coalition for Responsible Regulation. 684 F.3d at 120 (affirming "EPA's scientific evidence of record" supporting anthropogenic climate change); see 80 Fed. Reg. at 64,530 (concluding that evidence since 2009 "confirm[s] and enhance[s]" that record). Thus, while the statute does not require that EPA make a new endangerment finding to regulate sources already listed pursuant to Section

[60] The Rule addresses CO_2 alone "because other [greenhouse gases] represent less than 1 percent of the total estimated [greenhouse gas] emissions (as [CO_2-equivalent]) from fossil fuel-fired electric power generating units." 80 Fed. Reg. at 64,537.

111(b)(1)(A), the findings in the record not only support EPA's rational basis to regulate CO_2 for power plants under Section 111(b)(1)(B), but would—as EPA concluded—constitute an endangerment finding were one required. No other conclusion with respect to endangerment could be reasonable.

C. EPA Did Not List a New Subcategory, So No New Finding Was Necessary.

Petitioners separately contend that a new endangerment finding is required because EPA purportedly created a new source category. Non-State Br. 64; State Br. 35. Petitioners are incorrect. EPA concluded that codifying the Rule's requirements in a single subpart of EPA's regulations would reduce confusion. 80 Fed. Reg. at 64,531-32. But this practical measure—for which purpose EPA combined the source categories for steam units and combustion turbines into a single grouping ("fossil fuel-fired electric generating units")—did not create a new category. As EPA explained, "these two source categories are pre-existing listed source categories and the EPA will not be subjecting any additional sources in the categories to CAA regulation for the first time." Id. at 64,532. Moreover, grouping the two pre-existing categories together did not affect the scientific basis on which either category was listed in the first place; each emits the same pollutants in the same amounts whether the categories are regulated in the same or different parts of EPA's regulations. Just as EPA's decision to divide a pre-existing category is not a new listing decision, see id. at 64,528 & nn.100-01 (citing previous rulemakings), EPA's combination of pre-existing categories is not a new listing decision, so no endangerment finding is required.

VI. PETITIONER EELI'S ARGUMENTS ARE LEGALLY DEFICIENT AND FACTUALLY BASELESS.

Petitioner EELI's arguments regarding undocketed materials, which no other Petitioner joins,[61] are procedurally, legally, and factually deficient. First, EELI has failed to demonstrate its standing. A petitioner must demonstrate standing through affidavits or other evidence no later than the filing of its opening brief. See D.C. Cir. R. 15(c)(2) (codifying the holding of Sierra Club v. EPA, 292 F.3d 895, 900-01 (D.C. Cir. 2002)), R. 28(a)(7). Non-State Petitioners' opening brief contained no specific assertions of standing on behalf of EELI and its general assertions on behalf of fossil-fuel owners and operators, coal companies and associated labor unions, and challengers of the Clean Power Plan are insufficient to establish EELI's standing. Non-State Br. 15-16. EELI presented no evidence that it (or its members) belongs to the first two groups, and while EELI challenged the Clean Power Plan, it failed to timely prove its standing in that proceeding as well. See EPA's Opp. To Pet. EELI's Mot. 5-9 (DN 1600731), West Virginia v. EPA, No. 15-1363 (D.C. Cir. filed Oct. 23, 2015).

Nor is EELI's standing "self-evident" or "apparent from the administrative record." See D.C. Cir. R. 28(a)(7); Sierra Club v. EPA, 292 F.3d at 901. To have

[61] Non-State Br. 69 n.22.

standing before this Court, EELI—or its members—must demonstrate "actual or threatened injury in fact that is fairly traceable to the alleged illegal action and likely to be redressed by a favorable court decision." Food & Water Watch v. Vilsack, 808 F.3d 905, 919 (D.C. Cir. 2015) (citation omitted); see Hunt v. Wash. State Apple Advert. Comm'n, 432 U.S. 333, 343 (1977) (discussing standing on behalf of members). Neither EELI's comments on the Rule nor its petition for reconsideration identify an injury. See EELI Comments, EPA-HQ-OAR-2013-0495-10044, EPA-HQ-OAR-2013-0495-3593, JA1324-28, JA0319-0402; EELI Petition for Reconsideration, EPA-HQ-OAR-2013-0495-11891, JA4449-55. EELI's docketing statement, meanwhile, states that the Rule would (1) prevent EELI's public education and advisory efforts, and (2) injure EELI members by "causing economic harm to property interests and frustrating investment-backed expectations." Pet. Docketing Statement (DN 1586461), Energy & Env't Legal Inst. v. EPA, No. 15-1397 (D.C. Cir. filed Oct. 30, 2015). But EELI does not identify how the Rule could prevent it from educating or advising. See Food & Water Watch, 808 F.3d at 919 ("An organization must allege more than a frustration of its purpose" to have standing). Nor does EELI identify any of the members harmed, or trace their harms to this Rule or the redress this Court could provide. See id.

Second, EELI does not satisfy the CAA's requirements for review of alleged procedural errors. EELI does not establish, or even argue, that EPA's alleged failure to docket certain pre-proposal emails is "of central relevance to the outcome of the rule," such that reconsideration was improperly denied. See 42 U.S.C. § 7607(d)(7)(B); Reconsideration Memo 2, 36-38, JA4411, JA4445-47. Nor does EELI argue that "there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made," which is the Act's threshold for invalidating regulations on procedural grounds. 42 U.S.C. § 7607(d)(8), (d)(9)(D).

EELI asserts only that "the public or affected parties" could not "meaningfully … comment or contribute to the Rule's development." Non-State Br. 69. Yet no other "affected part[y]" joined EELI's argument, id. 69 n.22, and EELI presents no additional comments it would have made—let alone comments which would have had a "substantial likelihood" of "significantly chang[ing]" the Rule. See id. 69-75; see also Reconsideration Memo 36-38, JA4445-47. As this Court held in Union Oil Co. v. EPA, a docketing error is not grounds for reversing an agency decision—even where the undocketed information was of "central relevance"—if "petitioners fail to show the 'substantial likelihood' required by the [Clean Air] Act that the rule would have been changed." 821 F.2d 678, 683-84 (D.C. Cir. 1987).

Third, even if EELI's argument were properly raised, it is mistaken. EPA is only obligated to docket materials "on which the proposed rule *relies*." 42 U.S.C. § 7607(d)(3) (emphasis added). But the emails EELI identifies predate the Proposal by three years and discuss options for a different, superseded proposal for new sources that proposed a single standard for all fossil units, 77 Fed. Reg. 22,392 (Apr. 13, 2012). Non-State Br. 70-72; Reconsideration Memo 37, JA4446. EELI's conclusory assertion that the undocketed emails are relevant because this Rule's Proposal was "built entirely on the back of the 2012 proposal" is absurd: the alternatives discussed in the undocketed emails were not even adopted in that *2012* proposed rule, let alone the Rule under review. See Non-State Br. 73; Reconsideration Memo 37 (emails discussed a less stringent standard based on natural gas co-firing), JA4446. EPA did not err in declining to docket outdated emails concerning alternatives rejected from a superseded proposal.

Because EELI's claim is legally and factually unsupported, it must be rejected by this Court.

CONCLUSION

For the foregoing reasons, the petitions for review should be denied.

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE WITH FEDERAL RULE OF APPELLATE PROCEDURE 32

I hereby certify that this brief complies with the requirements of Fed. R. App. P. 32(a)(5) and (6) because it has been prepared in 14-point Garamond, a proportionally spaced font.

I further certify that this brief complies with the type-volume limitation established in the Court's Order of August 30, 2016 (DN 1632712) because it contains **30,942 words**, excluding the parts of the brief exempted under Rule 32(f), according to the count of Microsoft Word.

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CERTIFICATE OF SERVICE

I hereby certify that on February 6, 2017, I electronically filed the foregoing brief with the Clerk of the Court for the United States Court of Appeals for the District of Columbia Circuit by using the appellate CM/ECF system.

The participants in the case are registered CM/ECF users and service will be accomplished by the appellate CM/ECF system.

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