use diverse production methods and fuels to create the same end product. EPA's proposal comports with recent trends in the electricity market, reinforcing the move toward less expensive, lower carbon generation sources. Indeed, Joint Environmental Commenters suggest that EPA should go further and include in the same category all fossil fuel-fired electric generating sources that provide power to the grid, including simple cycle units, since they serve the same broad function. If EPA determines that units that that provide only peaking power should not be subject to the performance standard applicable to intermediate load and baseload units, EPA should adopt a separate standard for those units promptly, but EPA should not exempt any fossil fuel-fired generating units or differentiate among them based on technology or fuel type.

1. **The Combined TTTT Category Matches the Current Structure of the Power Sector**

EPA's inclusion of all fossil fuel-fired plants providing baseload and intermediate-load generation in a single NSPS category is appropriately responsive to new power sector market realities and will improve the environmental efficacy, economic efficiency, and regulatory coherence of the performance standards promulgated for sources in Subpart TTTT.

The first § 111 performance standards promulgated for power plants (in 1971) applied to steam-generating power plants that burned any type of fossil fuel (Subpart D) and governed emissions of SO_2, particulate matter, and NO_x.[57] These standards were revised in 1979, creating Subpart Da.[58] Also in 1979, EPA established performance standards for natural gas turbines to limit emissions of NO_x and SO_2 (Subpart GG).[59] These standards were revised in 2006, creating Subpart KKKK.[60] Also in 2006, EPA moved one type of baseload and intermediate load generating source (Integrated Gasification Combined Cycle Units (IGCC), previously covered under Subpart GG) into the Da category.[61] Following the pattern of consolidation of baseload generation that began in 2006 with the transfer of IGCC plants to Da, proposed category TTTT would encompass all fossil fuel-fired plants providing baseload and intermediate load generation – gas-fired combined cycle (CCNG) units (currently regulated under KKKK) and steam-generating

[57] Standards of Performance for New Stationary Sources, 36 Fed. Reg. 24876, 24879 (Dec. 23, 1971).
[58] New Stationary Sources Performance Standards; Electric Utility Steam Generating Units, 44 Fed. Reg. 33580 (June 1, 1979).
[59] Standards of Performance for New Stationary Sources; Gas Turbines, 44 Fed. Reg. 52792 (Sept. 10, 1979).
[60] Standards of Performance for Stationary Combustion Turbines, 71 Fed. Reg. 38482 (July 6, 2006).
[61] 77 Fed. Reg. at 22,411 (discussing 40 CFR part 60, subpart Da and 70 Fed. Reg. 9706 (Feb. 28, 2005)).

electric generating units and integrated gasification combined cycle units (currently regulated under Da) for the purposes of CO_2 regulation.[62]

Unlike when the NSPS categories were created, coal- and natural gas-fired power plants are now operating interchangeably to provide baseload and intermediate-load generation. An electricity supplier meeting new demand has the option of building a coal-fired plant or a natural gas-fired plant, investing in energy efficiency, or installing renewable generation. As between a coal-fired plant and a natural gas-fired plant, the economics strongly favor CCNG plants.[63]

It is difficult to overstate the transformation in energy markets that has occurred in the United States since the first power plant NSPS categories were listed. For many decades coal- and oil-fired generation provided the majority of baseload fossil fuel-fired generation in the United States,[64] while natural gas plants generally operated in intermediate-load and peaking modes.[65] In 1978, motivated by perceived scarcity of fossil fuel resources,[66] Congress passed and President Carter signed into law a *prohibition* on the use of natural gas in baseload power generation – preserving supplies for use in other applications.[67] In 1987, however, the prohibition was reversed.[68] Between 1988 and 2002 natural gas consumption for electric generation more than doubled,[69] and between 1998 and 2008 more than 90% of new electric capacity built in the United States was natural gas-fired generation.[70]

The shift towards natural gas generation in the power markets has accelerated since 2006 due to the increase in natural gas resources driven by the development of

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[62] 77 Fed. Reg. at 22410 – 22411.

[63] *See* EIA, Updated Capital Cost Estimates for Electricity Generation Plants (November, 2010) at 7. *Available at:* http://205.254.135.7/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

[64] EIA, Annual Energy Review 1995 (July 1996) at 235. http://205.254.135.7/totalenergy/data/annual/archive/038495.pdf.

[65] See 44 Fed. Reg. at 52796.

[66] *See, e.g.,* Jimmy Carter, National Energy Bills Remarks on Signing H.R. 4018, H.R. 5263, H.R. 5037, H.R. 5146, and H.R. 5289 Into Law, November 9 1978. "[W]e must shift toward more abundant supplies of energy than those that we are presently using at such a great rate, to coal[.]" *Available at*: http://www.presidency.ucsb.edu/ws/index.php?pid=30136&st=Industrial+Fuel+Use+Act&st1=#ixzz1yRwPuLkN

[67] Sec. 201. New Electric Powerplants, PL 95–620, November 9, 1978, 92 Stat 3289

[68] Sec. 201. Coal Capability of New Electric Powerplants; Certification of Compliance, PL 100-42, May 21, 1987, 101 STAT. 311

[69] EIA, Repeal of the Powerplant and Industrial Fuel Use Act, http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html

[70] Natural Gas Supply Association, Natural Gas Is Vital for Electric Power Generation (2008). *Available at*: http://www.ngsa.org/assets/Docs/Issues/NaturalGasIsVitalForElectricPowerGeneration.pdf

technology to access shale gas. Shale gas accounted for only two percent of total U.S. natural gas production in 2001, and 30 percent by 2011.[71] The U.S. Energy Information Administration projects that this growth will continue, and that shale gas will account for 47 percent of domestic natural gas production by 2035.[72] These developments have led to a sharp reduction in the cost of natural gas for electric power generation, with prices dropping by 60% from 2005 to 2012.[73] As noted elsewhere, Energy Information Administration data indicate that from 2007 to 2011 net coal generation fell from over 2 billion MWh to 1.73 billion MWh, and is set to decline further.[74] During the same period, net natural gas generation climbed from 869 million MWh to over 1 billion MWh, as a result of both increased capacity factors at existing plants and new facility construction. EPA predicts that it is likely to continue to increase.[75]

Today, natural gas plants are commonly operating as baseload plants, providing 25% of U.S. net power generation in 2011,[76] compared to only 10% in 1994.[77] As discussed elsewhere, market analyses project that only new natural gas units (as well as renewables and energy efficiency investments) will be built to serve any growth in energy demand.[78]

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[71] SEC'Y OF ENERGY ADVISORY BD, SHALE GAS PRODUCTION SUBCOMMITTEE 90-DAY REPORT 6 (Aug. 18, 2011), *available at* http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf [hereinafter 90-DAY REPORT].

[72] U.S. Energy Information Administration, Annual Energy Outlook 2011 (2011) at 79, *available at* http://205.254. 135.7/forecasts/aeo/pdf/0383(2011).pdf

[73] EIA, Natural Gas Monthly May 2012 at 7, http://205.254.135.7/naturalgas/monthly/pdf/ngm_all.pdf; EIA, Natural Gas Monthly December 2007 at 7, http://205.254.135.7/naturalgas/monthly/archive/2007/2007_12/pdf/ngm_all.pdf

[74]EIA, *Electric Power Monthly* (Apr. 2012) at Table 1.1., attached as Ex. **X**

[75] *Id.*

[76] EIA, Electric Power Monthly May 2012 at 11. http://205.254.135.7/electricity/monthly/pdf/chap1.pdf

[77] EIA, Electric Power Monthly July 1996 at 10. http://205.254.135.7/electricity/monthly/archive/pdf/02269607.pdf; In March 2012, natural gas provided 30% of U.S. net power generation, while coal provided 34%. *See* EIA, U.S. coal's share of total net generation continues to decline (June 5, 2012), *Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=6550*.

[78] *See, e.g.,* EIA, Annual Energy Outlook 2011 (2012) at Table A-9: Electric Generating Capacity. http://www.eia.gov/forecasts/aeo/er/pdf/tbla9.pdf; *See also* EIA, Annual Energy Outlook 2010 (2011) at 67. http://www.eia.gov/oiaf/archive/aeo10/pdf/0383(2010).pdf; Utilities' actions reflect this shift. PSEG plans to increase natural gas from 15 to 35 percent of its generation and shrinking coal's share from 35 to 15 percent. (Steven Mufson "Cheap natural gas jumbles energy markets, stirs fears it could inhibit renewable," The Washington Post (February 1, 2012)); and Southern Company CEO Thomas Fanning observed, "4 years ago…we were about 70% of our energy from coal, and … about 12% from gas … In the fourth quarter [of 2011] … our energy production was 40% coal, 39% gas…Now moving forward, given where gas prices are, we will

Where multiple processes are functionally interchangeable, they should be categorized together to allow for a more rational and comprehensive analysis of opportunities for emission reduction, in order that the most efficient and effective emission reduction opportunities can be identified while being responsive to market realities. As discussed below, EPA has often organized NSPS categories by function in recognition of this principle of regulatory and environmental efficacy.

Selecting a rational definition of source categories that properly reflects industry realities is especially critical given the enormous significance of the power generation sector in contributing to the urgent public health and welfare threats posed by greenhouse gas emissions. As noted elsewhere, the United States power sector is responsible for 40% of U.S. CO_2 emissions[79] and 11% of global CO_2 emissions.[80] Mitigating the risk of catastrophic climate change by curbing greenhouse gas emissions will require major emission reductions from fossil fuel fired power plants. Achieving those reductions as efficiently and cost-effectively as possible is of paramount importance. Grouping together CO_2-emitting sources that provide baseload generation allows EPA to identify the most cost-effective and efficient means of reducing emissions from these sources.

Finally, the categorization used for 111(b) standards also informs the 111(d) performance standards for existing sources. Including all major fossil fuel-fired power plant types in a single performance standard for existing plants will be of equal or even greater importance as EPA develops a 111(d) framework. Encompassing all fossil-fuel fired generation that provides power to the integrated electricity grid may well be essential for ensuring that emissions from existing power plants can be sharply but efficiently and cost-effectively reduced consonant with the statutory language.

2. **Source Categories May Encompass Multiple Production Methods and Fuels**

The statutory text plainly grants EPA discretion to create category TTTT. Section 111(b)(1)(A) directs EPA to designate "categor[ies] of sources . . . [that] cause[] or

continue to see much more gas production, so it'll become more important." Southern Company, Q4 Earnings Call Q&A, 1/25/2012.

[79] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2010 (April 15, 2012) at ES-4. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf

[80] *Id.*, showing US power plant CO2 emissions data; United Nations Framework Convention on Climate Change (UNFCCC), National greenhouse gas inventory data for the period 1990–2009 (2011) at 11, showing CO2 emissions data for annex I countries. http://unfccc.int/resource/docs/2011/sbi/eng/09.pdf.; UNFCCC, Sixth compilation and synthesis of initial national communications from Parties not included in Annex I to the Convention (2005) at 6, showing CO2 emissions data from non-annex I countries.

contribute[] significantly to air pollution which may reasonably be anticipated to endanger public welfare." EPA must revise its source category designations "from time to time." *Id.* EPA "*may* distinguish among classes, types, and sizes *within* categories of new sources." § 111(b)(2) (emphases added). Thus, the statute plainly contemplates source categories encompassing different "classes, types, and sizes" of sources, and grants EPA discretion to *not* create subcategories that distinguish among these.

EPA's Section 111(b)(1)(A) authority to revise the source category list includes authority to merge all or part of two existing categories. (We address the question of endangerment separately, below.) EPA undoubtedly has authority to revise the list to add categories covering sources that previously were wholly unregulated, and nothing in the statutory language precludes EPA from changing or combining categories that have already been listed as long as EPA has a rational basis for its categorization decisions.

Categorizing sources by end product, as EPA proposes here, is consistent with the legislative history of the Clean Air Act. In 1970, Congress emphasized that standards would apply to industrial categories, broadly defined, which would suggest focusing on product and pollution, not process:

> [the Agency] could establish uniform pollution control standards for the chemical, oil refining, foundries, food processing, and cement-making industry, and other industries. In each case the pollution control regulation would be directed to the specific pollution of a specific industry. Every plant within the same group could be required to maintain the same high standards. There would be no variation in pollution control procedure by a given industry by region or area of operation.

116 Cong. Rec. 19,218 (1970) (statement of Rep. Vanik).
Categorizing sources by end product is a reasonable and established approach to categorization. As EPA explains, "with the combination, all new fossil fuel-fired electricity generating units that meet specified minimum criteria will be subject to the same requirements, and therefore will be treated alike because they serve the same function, that is to serve baseload or intermediate demand." 77 Fed. Reg. at 22410. EPA has designated product-based categories as early as 1976, when EPA designated a single NSPS encompassing multiple copper smelting production methods. There, EPA set a single standard for new sources despite the use of four different smelting furnace technologies in the US at the time. *Standards of Performance for New Stationary Sources, Primary Copper, Zinc, and Lead Smelters,* 41 Fed. Reg. 2332-2333 (Jan. 15, 1976). EPA explicitly determined that a production method that inherently produced fewer emissions could be BSER, rejecting the argument that BSER only encompasses emission control hardware. *Id.* at 2333.

Since then, numerous other NSPS have categorized sources by function even though the sources may use different technologies, fuels, or processes. As noted in EPA's proposal here, EPA previously combined into one category units that generate electricity for baseload or intermediate demand, moving IGCC units from Category GG to Category Da. 77 Fed. Reg. at 22,411 (discussing 40 CFR part 60, subpart Da and 70 Fed. Reg. 9706 (Feb. 28, 2005)).

Before that, EPA published a "uniform [NSPS] for all utility boilers" for nitrogen oxide emissions, in which EPA set a single standard of 1.6 pounds of NOx per megawatt hour of electricity produced for all new plants, refusing requests to set separate relaxed standards (*i.e.*, to create separate categories or subcategories) for high-sulfur coal-fired boilers and fluidized bed combustion boilers. *Revisions of Standards of Performance for Nitrogen Oxide Emissions for New Fossil-Fuel Fired Steam Generating Units*, 63 Fed. Reg. 49,442, 49,445 (Sept. 16, 1998). EPA's decision to promulgate a single NOx standard, rather than to set "a range of standards by boiler and fuel type," was affirmed by the D.C. Circuit. *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

Similarly, EPA adopted a standard applicable to all rotary lime kilns, regardless of whether they were fueled by coal, natural gas, or oil. 47 FR 38832, 38843, see also 40 C.F.R. §§ 60.340(a), 60.342. Most recently, EPA promulgated a single standard for all Portland cement plants, rejecting calls for separate standards for different kiln types (*e.g.* "long wet," "long dry," "preheater," and "preheater with precalciner") or fuels. 75 Fed Reg. 54970, 55,010 – 55,012, 55,015 (Sept. 9, 2010). Promulgation of this single performance standard for different types of sources in the cement kiln category was upheld by the DC Circuit. *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177, 190-93 (D.C. Cir. 2011). *see also* 40 C.F.R. § 60.62(a).[81]

[81] EPA has also created product-based, rather than fuel- or method-based, categories under the section 112 NESHAP program. Section 112(c)(1) uses language similar to Section 111 in directing EPA to list "categories and subcategories" of sources. The Section 112 categories are to be "consistent with" the Section 111 categorizations "[t]o the extent practicable." *Id.* Section 112(d)(1) likewise provides that EPA "*may* distinguish among classes, types and sizes of sources within a category or subcategory." As EPA has observed, this statutory language is "almost identical" to the language used in Section 111, such that categorization under the two sections should be interpreted similarly. *National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, 77 FR 9304, 9378 (Feb. 16, 2012).

EPA's Section 112 decisions further demonstrate the appropriateness of the combined category here. EPA's recent NESHAP for Portland cement kilns, promulgated in conjunction with the NSPS discussed above, explicitly refused to subcategorize on the basis of "type of kiln, presence of an inline raw mill, practice of wasting cement kiln dust, total mercury inputs [from different fuel types or from differing limestone inputs], or geographic location." 75 Fed. Reg. at 54,978 (citing

As these examples demonstrate, EPA may – and frequently has – put sources that use different processes in the same category even when one process can meet a stronger standard than the other, or can meet the same standard at lower costs than the other. As early as the copper smelter NSPS, EPA explained that it could set a "single standard [that] would effectively preclude using a process which is much less expensive than the permitted process" so long as the total cost of standard was reasonable.[82] 41 Fed. Reg. at 2333-2334. Thus, EPA adopted a copper smelting standard that EPA acknowledged "favored construction of new flash and electric furnaces over new reverberatory smelting furnaces," the latter of which would face greater expense in meeting the standard. 41 FR 2332-2333. The Portland cement kiln NSPS similarly adopted a uniform NOx standard despite concluding that older kiln designs would face greater costs in meeting this standard. *Portland Cement Ass'n*, 665 F.3d at 190. The statute does not entitle a lagging process – one that is inherently more polluting than another, or one that can meet a given emission level only at higher cost than another – to its own category or subcategory with a weakened standard.

As EPA has correctly stated here, Section 111(a)(1) defines a standard of performance as "*a* standard" reflecting "*the* degree" of emission limitation achievable through application of "the *best* system of emission reduction" that, taking into account costs and other factors, "the Administrator determines has been adequately demonstrated" (emphasis added). The use of the singular and the superlative belie any requirement to water the standard down to accommodate lagging technologies.

To be sure, Section 111(b)(2) states that the Administrator "*may* distinguish among classes, types, and sizes within categories for the purpose of establishing such standards" (emphasis added), but the statute does not require such

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the earlier proposal, 74 Fed. Reg. at 21,144-21,145). The Cement Kiln NSPS, like the NESHAP, did not subcategorize on any of these divisions either. In promulgating a NESHAP for "hardboard" composite wood product processing, EPA adopted a single standard for multiple production methods and refused to promulgate a variance procedure for an uncommon process that would face higher costs in achieving the standard. *Natural Res. Def. Council v. E.P.A.*, 489 F.3d 1364, 1375 (D.C. Cir. 2007) (citing National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products, 69 Fed. Reg. 45,944 (July 30, 2004)). This decision was upheld by the DC Circuit. *Id.* In the rulemaking, EPA determined that equipment should be classified "according to its function," including the end product and the market in which that product competes. *Id.* (citing 69 Fed. Reg. at 45,948, Summary of Public Comments and Responses at 2-49 (Feb. 2004)). Available at http://www.epa.gov/ttn/atw/plypart/pcwp_final_bid_feb2004.pdf.

[82] Put differently, EPA concluded that the fact that a standard would "effectively preclude" a certain production method was not itself a demonstration that the standard was unreasonable or not economically achievable.

subcategorizations.[83] If, as here, EPA has a reasonable basis, considering the factors in Section 111(a)(1), to hold an entire category of sources to the same emission standard, there is no requirement to set a separate standard for one subgroup. In this case, as EPA has explained, the fact that prospective plant builders have the alternative of building an NGCC plant that can meet the proposed standard at reasonable cost is a sufficient basis for requiring that standard for all fossil fueled EGUs performing the same function. The alternative pathway for coal-fired power plants that install carbon capture and sequestration technology provides additional flexibility for processes other than NGCC to comply, making EPA's action even more reasonable.

3. **Industry Trends Support A Fuel-Neutral Standard**

EPA has strong support for its forecast that only gas-fired power plants will be built to serve baseload and intermediate load growth from other governmental forecasts, and from the electric power industry and financial world. Market analyses project that only new natural gas units (as well as renewables and energy efficiency investments) will be built to serve any growth in energy demand. As Brookings senior economist Peter Wilcoxen explained in April:

> To put it simply: the life-cycle costs of coal-fired power are considerably higher than gas-fired power. This is not a theoretical matter: over the last decade, the electric power sector has responded by adding more than about 200 gigawatts of gas-fired capacity and about 2 gigawatts of coal. The US now has considerably more gas-fired capacity than coal-fired capacity and low gas prices will accelerate that trend even without the EPA decision.[84]

Wilcoxen continued: "Finally, because it only rules out an expensive option that wouldn't have been used anyway, the EPA rule will have no significant effect on electricity prices."

Power companies simply aren't planning to build new coal plants, due to the availability of low-cost natural gas, strong growth in wind and solar power, big opportunities to improve energy efficiency, and even the potential for nuclear power. For example, the country's largest current CO2 emitter, American Electric Power, told the National Journal in March that the proposed rule "doesn't cause immediate concern" for the company. "We don't have any plans to build new coal plants," said AEP spokesperson Melissa McHenry. She continued, "Any additional generational plants we'd build for the next generation will be natural gas." Similarly, PSEG plans to increase natural gas from

[83] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA is not required by law to subcategorize – section 111 merely states that 'the Administrator *may* distinguish…within categories.'" (emphasis in the original)).
[84] http://mediamatters.org/research/201204020012.

15 to 35 percent of its generation and shrink coal's share from 35 to 15 percent. And Southern Company CEO Thomas Fanning observed, "4 years ago…we were about 70% of our energy from coal, and … about 12% from gas … In the fourth quarter [of 2011] … our energy production was 40% coal, 39% gas. . . .Now moving forward, given where gas prices are, we will continue to see much more gas production, so it'll become more important."

EPA's proposed action would be fully justified even if it would tip prospective plant builders away from building a new coal-fired EGU they otherwise would have built, and thus even if it would result in changing the forecast of what types of EGUs would be built in the absence of the standard. Standards of performance under Section 111 are intended to shift industry towards lower-emitting source designs and technologies. The standard would be fully justified even if it in fact raised the cost of new electric power generation above the no-standard forecast. While the courts have opined that Section 111(b) may rule out standards that impose "exorbitant" costs, Lignite Energy Council, 198 F.3d at 933 (citing National Asphalt Pavement Ass'n v. Train, 539 F.2d 775, 786 (D.C. Cir. 1976)), the statutory language provides no guarantee that compliance with standards must be achievable at the same cost for all technologies. The statute is "technology forcing"– forcing regulated entities to reach for potentially more expensive, but more protective, technologies even if the unregulated market would not lead to those choices.

This situation presents an even easier case, however, because EPA is following, rather than steering, industry trends. EPA has correctly assessed that no new conventional coal-fired EGUs are expected to be built in the baseline forecast: "[E]conomic models forecast no new construction of coal-fired generation without CCS through the analysis period, which extends until 2020 (when the standard will be revisited)." (Actually, EPA's Regulatory Impact Analysis and other forecasts support this conclusion through 2030, as discussed below.) As EPA concluded: "Because of those economic conditions, there is a strong independent movement of power plants serving baseload generation toward NGCC. In light of that movement, it is appropriate for the EPA to focus on this technology in developing the standard, rather than subcategorizing and providing a separate standard for new coal units."

In short, EPA has correctly assessed that due to baseline market realities – market realities absent this proposed standard – the nation is reasonably expected to meet its electricity needs over the next two decades without constructing new coal-fired plants. As a result, the proposed new source standard actually will impose no additional costs on the industry or on electricity rate-payers and will have no adverse impact on jobs. These market forecasts are robust. As discussed further, below, sensitivity analyses in EPA's Regulatory Impact Analysis show that power companies will not choose to construct any new conventional coal-fired plants before 2030 even if natural gas becomes 4-5 times more costly than it is today and power demand increases faster than expected.

The strength of these forecasts gives the lie to claims that the proposed standard is a "de facto" ban on new coal plants. If power companies simply are not going to build new coal plants for fundamental market reasons in the absence of the proposed carbon pollution standard, then that standard obviously can't be blamed for blocking new coal plants. The problem for new coal plants is that there is no market demand for them. The charge of a "de facto" ban is scapegoating, pure and simple.

These major changes in the fossil generation component of the electric generation industry have significant implications for EPA in carrying out its delegated rulemaking authority to establish standards of performance for greenhouse gas emissions from the power sector. EPA was not only authorized, but required, to take these new fundamental industry realities into account when establishing emissions standards to achieve the "best system of emission reduction" for an important newly regulated pollutant that is emitted in substantial volumes by all fossil fuel-fired power plants.

As EPA has pointed out, courts have specifically approved EPA's setting a standard based on one technology path when that is the path the industry is expected to follow in the underlying baseline market forecast. Id. at 22,411/1, citing Portland Cement Ass'n v. EPA, 665 F.3d 177, 190 (D.C. Cir. 2011) for "affirming the EPA's decision not to subcategorize in part because of 'the universal movement in the portland cement industry towards adoption of preheater/precalciner technology'."

Companies in practice compare natural gas and coal when investing in new baseload power generation, and market fundamentals have dramatically shifted to expansive reliance on gas-powered electricity generation. By including these functionally equivalent sources in the same category, EPA can more effectively assess the "best system of emission reduction" available. It is eminently sensible, indeed compelled by the strong normative term "best," for EPA to provide a fuel-neutral analysis of the best system of emission reduction. Cleaner fuels are often an important component of an effective system of emission reduction. Conversely, not to group these plants together and analyze the best system of emission reduction available for them, when they perform the same function and emit the same pollutant, would fall short of § 111's mandate to secure the maximum emission reductions available, taking cost and other relevant impacts into consideration.

As the Agency has noted previously, the NSPS does not protect high-polluting processes:

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

> purpose of section 111 to require maximum feasible control of new sources. In general, therefore, the Agency believes that section 111 authorizes the promulgation of one standard applicable to all processes used by a class of sources, in order that the standard may reflect the maximum feasible control for that class.

Standards of Performance for New Stationary Sources, Primary Copper, Zinc, and Lead Smelters, 41 Fed. Reg. 2332, 2333-2334 (Jan. 15, 1976).

4. **Treatment of Peaking Units and Simple-Cycle Gas-Fired Units**

EPA has asked for comment on the treatment of simple cycle natural gas-fired units that are currently within Category KKKK, and which EPA has proposed not to include in Category TTTT. EPA specifically requested comment on the option of excluding from Category TTTT facilities with permit restrictions limiting operation to less than 1/3 of their potential electric output, or approximately 2,900 hours of full load operation annually.

a. **Distinctions Among Fossil Fuel-Fired Power Plants Should Be Based on Function Rather than Purpose or Technology.**

Joint Environmental Commenters strongly support EPA's decision to combine fossil fuel-fired sources into one category, but we do not support EPA's blanket exclusion of all new simple cycle natural gas-fired units from the category. EPA has failed to justify excluding simple cycle units from any performance standard for GHG emissions. Indeed, there are compelling reasons for including all fossil fuel power plants that provide electricity to the grid in the same category. These units share the same broad function and they are operated as an integrated system.

If a distinction is needed between a peak-load unit and an intermediate-load or baseload unit, that distinction should be made on a functional, objective criterion – e.g., a legally-enforceable limit on how a unit is used – not on the basis of technology type or statements of the owner's or operator's purpose in constructing it. Insofar as EPA proposes to distinguish peaking units from baseload and intermediate- load units, true peakers can be effectively distinguished by an enforceable hours-of-operation limit, and a standard of performance can be rationally tailored to their limited utilization, rather than by categorically excluding all simple-cycle turbines or referring to the "purpose" for which units are constructed. As we discuss below, any such new units used for more than 2000 hours per year[85] should be considered to be serving baseload or intermediate load demand, and should be subject to the same emission limit as other new plants serving such load. To the extent that EPA concludes that peaking units should not be subject to the same standard, EPA should promptly set a separate appropriately tailored standard of performance in a supplementary rulemaking, but should not delay finalizing this rule.

This approach would preserve the option of prospective owners and operators to select designs that fit their expected patterns of use. If the builder of a new combustion turbine wants the option to use the unit for more than peaking purposes, it can add a heat recovery steam generator, for example, to increase the unit's efficiency and reduce its emission rate below the standard (turning the unit into an NGCC). This approach is a cost-effective emission control strategy for units designed to operate more than 2,000 hours per year.

There are several additional advantages to relying on a functional definition of intermediate-load and baseload EGUs, rather than including a categorical exclusion based on a particular technology. First, while market conditions make it unlikely that any new simple cycle combustion turbines would be built for use more than 2,000 hours per year, if such units were so operated there would be significant public health and environmental benefits to requiring them to comply with the proposed standard. Second, a functional approach is more robust in the face of unanticipated technological developments, which, for example, could make simple cycle turbines an economical option for intermediate-load operations – in which case they should be subject to the best system of emission reduction identified for sources serving that purpose. Finally, including an unnecessary categorical exemption from the proposed standard only serves to create the possibility that generators would seek ways to evade the standard by finding ways to qualify for that exemption.

b. The Definition of Electric Generating Unit Does Not Serve to Distinguish Peaking Units from Intermediate-Load and Baseload Units.

EPA has proposed the following definition of electric generating unit:

> *Electric utility generating unit* or *EGU* means any steam electric generating unit or stationary combustion turbine that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale.

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[85] Our proposal below, includes a limit on daily hours or operation. Here we employ a short hand "2000 hours per year" to facilitate discussion of this recommendation.

This definition raises several concerns with regard to the possibility of using it to address peaking units. As an initial matter, any definition that relies solely on the "purpose" of a unit will be difficult, if not impossible, to enforce, especially if market conditions lead an operator to "repurpose" a unit after construction. EPA should revise this definition to provide for more objective criteria for defining an EGU. Further, EPA has not provided any rationale for its proposed use of the "**potential**" electric output of a unit or the reason why "one-third of the potential electric output" should differentiate between EGUs and non-EGU units. While this definition may not have been problematic in the past, the adoption of the proposed CO_2 emission limits may create significant new incentives for coal or gas units to circumvent the rules.

We note that peaking units and even intermediate-load units are built with the purpose of supplying less than one third of their potential electric output to the grid. Peaking units ordinarily have capacity factors of less than 15 percent and intermediate load NGCC units may operate for relatively few days per year so that their electric output is less than the proposed 33 percent of potential output. Further, such units may, and often do, operate at less than full load – an intermediate load unit could operate at 60 percent load factor for half of the year and still not generate 33 percent of its potential electric output capacity. Joint Environmental Commenters therefore strongly urge EPA to change the EGU definition to eliminate this significant loophole.[86] By limiting the sources included in the category to only those that supply more than one-third of their *potential electric output capacity* to the grid, EPA would exclude units that operate at a significant capacity for a significant portion of the year (e.g. 60 percent capacity for half the year). Such units are intermediate load rather than peaking units and should be subject to this standard. We believe this problem may be remedied if the definition is clarified so that a source is an EGU **if at any time** it provides more than one-third of its rated name plate energy capacity to the grid.

c. The Data Suggest that Simple Cycle Units Are Not Only Used to Serve Peak Power and that Peaking Units Are Those that Operate No More than 2000 Hours per Year.

The available data show that almost all simple cycle combustion turbine ("CT") units have low operating hours – but they also appear to show that there are a number of large CT units with high capacity factors. As discussed above, EPA should not use the definition of electric generating unit to define peaking units because this suggestion leaves open the possibility of intermediate-load units operating at less than rated

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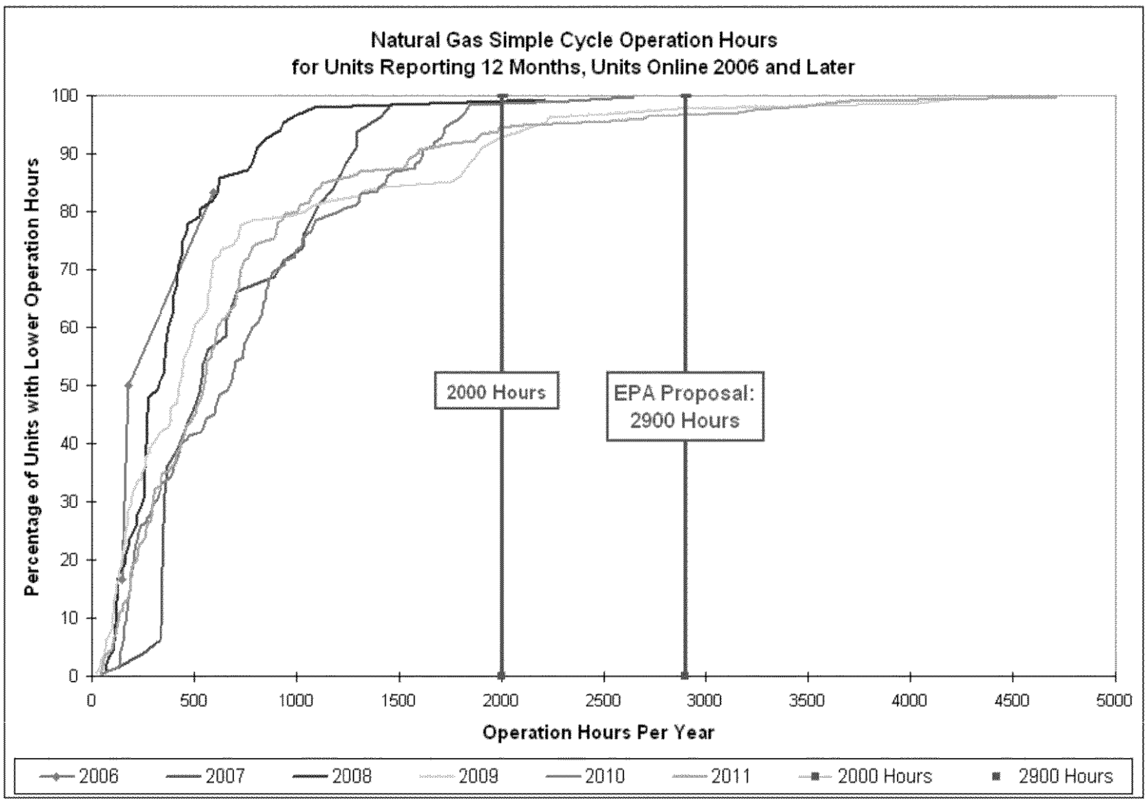
[86] We further suggest that EPA could accomplish its goal of providing separate treatment of peakers by defining EGUs without any reference to peakers, so that peakers remain in category TTTT, but by amending proposed section 60.5520(d) to provide a separate standard for peakers, defined using the approach we advocate above.

capacity for long periods of time being classified as peaking units. EPA has suggested that an alternate approach might be to establish a limit on the annual hours of operation of peaking units. We agree that an enforceable hour of operation limit is part of an appropriate alternative approach, but the histogram in Figure 1 shows that EPA's suggested 2900 hours is too high. The "knee in the curve" for these data appears to be below 2000 hours for 2011 (the most favorable[87] year for industry), thus showing that operation greater than 2000 hours is not consistent with the normal operation of CTs.

Figure 1. Hours of Operation for Combustion Turbines, by Year

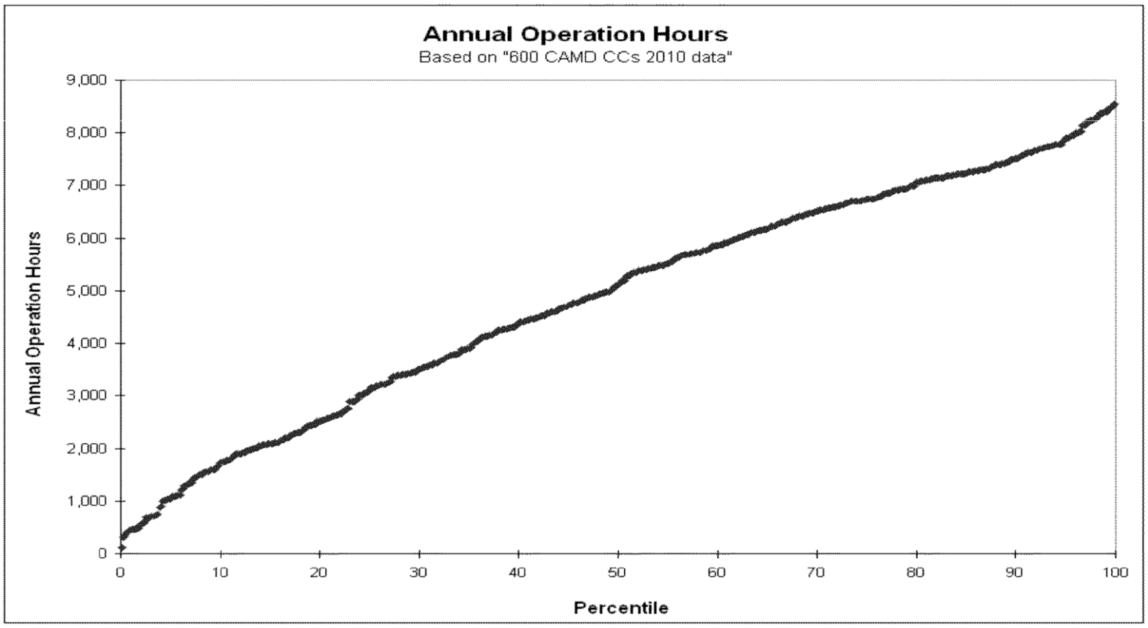


We note that even 2000 hours of operation may represent CTs that are in intermediate load rather than peaking operation, especially if such use is seasonal. We also note that there are a substantial number of combined cycle units that are designed for intermediate load applications but that may have limited hours of operation because of market conditions. Eighty-two of the 592 recently constructed[88] combined cycle units in

[87] For 2008, it is closer to 1100 hours.
[88] First year of operation 2006 or later.

the EPA CAMD data set, Figure 2, operate less than 2000 hours per year; 143 of those units operated less than 2900 hours per year.

Figure 2. Hours of Operation for Combined Cycle Units



These data suggest that an hour of operation test is needed, but that such a test, standing alone, does not sufficiently differentiate peaking from intermediate-load units that may operate seasonally, but for many hours at a time once started up. Such units are seasonal or load following, properly classified as intermediate load units. These units are not true peaking units and are within the functional category defined by EPA. Here, industry practice provides what appears to be the most useful definition of a peaking unit. General Electric defines "peaking" units in terms of an average hour of operation per startup. GE Performance defines base load as operation at 8,000 hours per year with 800 hours per start. It then defines peak load as operation at 1250 hours per year with five hours per start.[89] We urge EPA to include an hour per operating day limit as well as an annual hours of operation limit in its definition of peaking units to (1) properly define peaking units and (2) ensure that, if simple cycle CTs are used as base load or intermediate load units, the emission limits associated with those functions apply. To provide operators with a measure of flexibility, while still distinguishing between seasonally operated intermediate-load units and peaking units, we recommend that the GE norm of 1250

[89] Brooks, F., GE Power Systems, *GE Gas Turbine Performance Characteristics, GER-3567H*, p.14, accessed at http://www.muellerenvironmental.com/documents/GER3567H.pdf

hours per year be relaxed to 2000 hours per year and that the 5 hours per start definition be modified to an 8 hour per operating day limitation, established on a 30-day rolling average basis. EPA should establish the annual hour of operation limit on a rolling annual basis, with the calculation rolled daily.

5. **Treatment of CHP Units**

Under EPA's proposal a unit is not an EGU unless more than one-third of its potential generating capacity is intended to be sold to the grid. Thus, many combined heat and power units (whether coal, oil or natural gas-fired) would be exempt from EPA's proposed rules. However, based on the perceived environmental benefits of CHP, EPA has requested comment on allowing such units to be exempt even if they sell up to 80 percent of their useful output as electricity to the grid. This would seem to be a dangerous incentive for EGUs to avoid the strictures of the rule by partnering with smaller industrial operations. The likely result of the exemption EPA is considering would be substantially increased GHG emissions with no countervailing environmental benefit. Joint Environmental Commenters therefore strongly oppose exempting CHP units if more than one-third third of their potential generating capacity is intended to be sold to the grid.

EPA has also solicited opinion about how to account for CHP emissions. The EPA proposal would allow CHP units to count 75 percent of their thermal output as part of their gross output used to calculate their emission rate in demonstrating compliance. However, the more appropriate way to recognize the potential environmental benefits of CHP is to appropriately account for the emissions associated with useful thermal output. We believe that it makes more sense to deduct the CO_2 emissions from CHP units that is associated with their other uses of a portion of the energy created, rather than adding a "theoretical" electric generation (representing the amount of electricity that would have been generated by steam used onsite) to their output. Both approaches have a similar result—the effective emission rate for CHP units is reduced for compliance purposes. However, it is more appropriate to assign the emissions associated with producing used thermal output to the sector where that thermal energy is used (which is outside the scope of this standard) than it is to assign theoretical additional electric output to CHP units based on their thermal output. The emissions to be deducted should be calculated by determining the emissions that would have been generated had the useful thermal output been produced in a separate thermal-only facility. This approach obviates the need to determine how to convert thermal output to electricity output for compliance purposes (e.g. crediting 75 percent versus 100 percent of a CHP unit's thermal output for the purpose of calculating its electricity generation emissions rate).

B. EPA Has Reasonably Determined that EGUs in Category TTTT May Reasonably Be Anticipated to Endanger Public Health or Welfare and That Their CO_2 Emissions Contribute Significantly to Endangerment

As noted above, Section 111(b)(1)(A) states that the Administrator "shall include" a category of sources in the list for which standards are required "if in [her] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Reading the statutory language, "it" refers to the category, not to specific pollutants from the category. Section 111(b)(1)(B) then directs the Administrator to "establish[] Federal standards of performance for new sources within" a listed category. Section 111(a)(1) defines a "standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction" which the Administrator determines to have been adequately demonstrated. The endangerment and contribution findings are components of the process of listing a category of sources, and not a part of the process of promulgating standards of performance for particular air pollutants emitted by those sources. As a result, EPA has a strong plain language argument for interpreting Section 111(b)(1) as not requiring a specific endangerment or contribution determination for greenhouse gas emissions from sources in Category TTTT – namely, that EPA made the required endangerment and contribution determinations when the agency first listed the new category's two components, Categories Da and KKKK. The proposal correctly states:

> [S]ection 111 does not by its terms require that the EPA make any endangerment finding with respect to those particular pollutants [greenhouse gases], or any cause-or-contribute significantly finding with respect to the source category, at the time the EPA promulgates the standards of performance for those pollutants.

77 Fed. Reg. at 22,412/2.

The proposal nonetheless notes that it may be argued that endangerment and contribution determinations are needed when issuing performance standards for a pollutant not previously covered. EPA asks for comment on whether those determinations must be specifically made under Section 111 or whether relevant determinations made under other proceedings can be considered.

Joint Environmental Commenters submit that the endangerment determination made for greenhouse gases, including CO_2, in December 2009 fully satisfies any requirement under Section 111, not only for category TTTT, but for any other category for which EPA may set greenhouse gas standards going forward. EPA made very clear in the 2009 final rule that the endangerment component of that rule was generic – it applied with equal force to anthropogenic greenhouse gas "air pollution," irrespective of the sources from which greenhouse gas "air pollutants" were emitted.

Section 202(a)(1) provides:

> The Administrator shall by regulation prescribe (and from time to time revise) in accordance with the provisions of this section, standards applicable to the emission of any *air pollutant* from any class or classes of new motor vehicles or new motor vehicle engines, which in his judgment cause, or contribute to, *air pollution* which may reasonably be anticipated to endanger public health or welfare.

(emphasis added.) Thus, the statutory provision applied in the 2009 endangerment finding required EPA to consider whether the "pollution" may reasonably be anticipated to endanger (not the "pollutant"). EPA explained:

> As discussed in the Proposed Findings, to help appreciate the distinction between air pollution and air pollutant, the *air pollution* can be thought of as the total, cumulative stock in the atmosphere, while the *air pollutant,* can be thought of as the flow that changes the size of the total stock.

74 Fed. Reg. 66536 (emphasis in original). Thus, in finding endangerment, the 2009 finding determined that the "total, cumulative stock" of GHGs—not just mobile source emissions—could reasonably be anticipated to endanger. And as the 2009 finding makes clear, the total, cumulative stock of GHGs includes EGU emissions. 74 Fed. Reg. 66539-40. Indeed, EGUs are "the largest emitting sector," *id.* 66539, larger than §202(a) sources, *id.* 66540 (§202(a) sources' emissions are "behind the electricity generating sector").

The endangerment determination was made after an extraordinarily thorough scientific review and after full consideration of public comments. It was reaffirmed after full consideration of petitions for reconsideration.

There is no basis in the statutory text for requiring EPA to re-do this endangerment determination in a Section 111 rulemaking. This would be true even if more time had passed since the 2009 determination. Nothing in the statute requires EPA to re-make or refresh the 2009 endangerment determination for greenhouse gas air pollution when subsequently taking action regarding the greenhouse gas emissions of a specific category of mobile or stationary sources or other emission sources under Section 202, Section 111, or any other regulatory provision of the Act.

Indeed, EPA has made many previous decisions under Section 111 to cover a pollutant emitted by a category when an endangerment finding for that pollutant had been previously made. While EPA examined the category's emissions of air pollutants and the availability of control measures, in no case did EPA consider or reconsider whether the pollutant endangered public health or welfare. For example, in 1973 EPA included limits for particulate matter emissions in the standards of performance for asphalt concrete plants.[90] EPA had previously determined that particulate matter endangers public health and welfare. EPA issued the particulate matter emission limits for asphalt concrete in reliance on that earlier determination, without any review of endangerment in the Section 111 rulemaking.[91] More recently, in 2010, as part of the (overdue) eight-year review of the standards for cement kilns under Section 111(b)(1)(B), EPA added limitations for cement kilns' emissions of oxides of nitrogen (NO_x). Here again, EPA did so without reviewing whether NO_x endangers public health or welfare, either directly or as a precursor to ozone or fine particles.

Thus, both the statutory text and EPA's long-established practice confirm that an endangerment determination has no expiration date. If someone believes there is a new and significant scientific basis for revising or rescinding an endangerment determination, that party has the option of petitioning EPA for a new rulemaking.[92]

While the 2009 endangerment determination was generically applicable to all anthropogenic greenhouse gas air pollution, the contribution determination formally made in that rulemaking related solely to motor vehicle emissions. The 2009 finding did note, however, that power plants' carbon dioxide emissions are double those of cars and light-duty trucks. If Section 111(a)(1)(A) is interpreted to require a determination that the emissions of sources in Category TTTT "cause or contribute significantly" to greenhouse gas air pollution, then such a requirement is easily met for this category. As EPA states: "Fossil fuel-fired electric utility generating units are by far the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S." In fact, EGUs are responsible for approximately 40 percent of total U.S. energy-related CO_2 emissions,[93] and almost one third of total U.S. greenhouse gas emissions. 77 Fed. Reg. at 22,403-04 (Tables 2 and 3). U.S. EGUs are responsible for nearly 10 percent of all global anthropogenic CO_2 emissions. As the proposal states:

> [U]nder this alternative interpretation, in today's rulemaking, the EPA proposes to find that CO_2 emissions from fossil fuel-fired EGUs cause or contribute significantly to the GHG air pollution. The EPA's basis for this proposed finding is, in part, that the large amounts of CO_2 emitted by fossil fuel-fired EGUs clearly exceed the low hurdle necessary for the cause-or-contribute-significantly finding. As noted above in Tables 2 and 3, fossil fuel-fired EGUs emit almost one-third of

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[90] 38 Fed. Reg. 15,380 (June 11, 1973).

[91] The PM standard was upheld in *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775 (D.C. Cir. 1976).

[92] *Oljato Chapter of Navajo Tribe v. Train,* 515 F.2d 654 (D.C. Cir. 1975).

[93] 77 Fed. Reg. at 22,403/1-2 ("In 2009, the electric power sector—consisting of those entities whose primary business is the generation of electricity—accounted for 40 percent of all energy-related CO_2 emissions.")

> all U.S. GHG emissions, and constitute by far the largest single stationary source category of GHG emissions.

Id. at 22,413/1.

Joint Environmental Commenters agree with EPA that "so great is the contribution of CO_2 air pollutants from EGUs to GHG air pollution, that it is simply not necessary in this rulemaking to determine thresholds for when a contribution may be considered to be a ''significant[]'' contribution." *Id.* We also agree that "[i]f it were necessary, the EPA proposes that a limited amount of contribution would meet that standard in light of the fact that GHG air pollution is caused by a large number of types of sources and that no one source category dominates the entire inventory." *Id.* These plainly are reasonable conclusions and the only conclusions with respect to carbon pollution that are consistent with the Clean Air Act's overarching purpose to protect public health and welfare.

As a practical matter, Joint Environmental Commenters see little distinction between what the agency calls its first and second alternative interpretations. Under either of these interpretations, reliance upon the 2009 endangerment determination together with the 2010 disposition of the reconsideration petitions readily satisfies any requirement in § 111 for a determination that anthropogenic CO_2 emissions may reasonably be anticipated to endanger public health or welfare. Although not necessary, EPA could supplement that determination in this rulemaking with reference to the 2010 and 2011 assessments of the National Academy of Sciences, or other subsequent scientific assessments. Likewise, under either alternative interpretation, the facts EPA has cited regarding CO_2 emissions from EGUs in the TTTT Category – "The fact that affected EGUs emit almost one-third of all U.S. GHGs and comprise by far the largest stationary source category of GHG emissions," *id.* at 22,413/2 – more than amply demonstrate that these emissions contribute significantly to that dangerous air pollution.

Finally, we agree with EPA that it is not necessary in this rulemaking to determine a lower limit for "significant" contribution. Petitioners in the challenge to the 2009 endangerment finding are arguing that the finding is invalid because EPA did not define a threshold distinguishing non-endangerment from endangerment. EPA rejoined it does not need such a threshold:

> In sum, EPA does not need to quantify the myriad possible combinations of risk of harm and severity of harm, covering the very wide range of relevant climate and environmental circumstances, that would *not* constitute endangerment before it may make a fully rational judgment that the specific facts and circumstances here *do* in fact amount to endangerment.

EPA Endangerment Br. (D.C. Cir. 11-14-2011), at 87. Similarly here, EPA doesn't have to define what categories might not contribute significantly, given that the category at issue clearly does contribute significantly. In the 2009 finding, EPA has already found §202(a) emissions contribute to endangerment. In doing so, the agency noted inter alia:

> For example, the emissions of well-mixed greenhouse gases from CAA section 202(a) sources are larger in magnitude than the total well-mixed greenhouse gas emissions from every other individual nation with the exception of China, Russia, and India, and are the second largest emitter within the United States behind the electricity generating sector. As the Supreme Court noted, ''[j]udged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts* v. *EPA,* 549 U.S. 497, 525 (2007).

74 Fed Reg. 66499. If U.S. §202(a) emissions exceed those of most countries, then the even larger emissions from U.S. EGUs do so as well. If U.S. §202(a) emissions (in the words of the Supreme Court in *Mass. v. EPA*), "[j]udged by any standard," make a "meaningful" contribution to GHG concentrations and global warming, then so do the even larger emissions from U.S. EGUs. 5. While neither the 2009 finding nor *Massachusetts v. EPA* addressed the word "significantly" as it appears in §111, it seems at least reasonable – indeed, inevitable – for EPA to conclude that a source category contribution that exceeds the emissions of most countries and is "meaningful" is also "significant[]."

III. Determination of BSER

A. EPA Has a Duty to Adopt Emission Standards for Greenhouse Gas Emissions From EGUs

The proposed rules stem from litigation regarding EPA's mandatory duty to review NSPS standards under § 111(b)(1)(B). Every eight years, EPA must: (1) review its standards, (2) determine whether it is "appropriate" to revise them, including whether it is appropriate to add additional pollutants to the standards, and (3) if so, revise them accordingly. Here, EPA has concluded that it is appropriate to add an additional pollutant, carbon dioxide, and is therefore proposing standards. This is a proper (if delayed) effectuation of the mandatory eight-year review.

EPA has long interpreted this "appropriateness" determination to turn on two factors: (1) the amount of emissions of a given pollutant from that source category and (2) the availability of demonstrated control measures. [94] This two part test was appropriate in

[94] As EPA stated in reviewing the standards governing portland cement plants: "We have historically declined to propose standards for a pollutant where it is emitt[ed] in low

previous rulemakings because there was no dispute about whether the source category in question was properly listed under § 111(b)(1)(A) or whether the air pollutant was one that could be regulated in a standard of performance, as defined in § 111(a)(1). In this instance, the source category was properly listed (as discussed above) and carbon dioxide is properly an air pollutant (as discussed above). Thus, EPA was correct in determining that it is appropriate to regulate carbon dioxide under the NSPS.

In fact, Joint Environmental Commenters believe that any other conclusion would be beyond EPA's discretion. Given the fact that all of the sources in question are regulated within a source category already and that carbon dioxide is an air pollutant, *Massachusetts v. EPA*, 549 U.S. 497 (2007), for which an endangerment finding has been made, EPA could come to no other rational conclusion during its eight year review. EGUs unquestionably emit large amounts of carbon dioxide, and there is an adequately demonstrated system of emission reductions: natural gas combined cycle technology. Since EPA has a mandatory duty to review its NSPS every eight years, to decide against setting emission limits for carbon dioxide the agency would have to deny one of the foregoing facts. We submit that so concluding would be arbitrary and capricious, and that therefore NSPS regulation is compelled by the Clean Air Act.

B. The NSPS Program Is Intended to Be Technology Forcing to Reduce Emissions from High-Emitting Sectors.

1. Congress Established and the Courts Have Affirmed the NSPS as a Program Intended to Drive Innovation to Reduce Emissions.

Congress created the NSPS program in order to drive down emissions of dangerous air pollutants from major sources of pollution, and designed it to be technology-forcing in systems of emission reduction. The Senate Committee Report issued prior to passage of the Clean Air Act in 1970 stated that "[s]tandards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources."[95] The Senate Report also clarified that an emerging control technology used as the basis for standards of performance need not "be in actual routine use somewhere."[96]

Long-established case law confirms that NSPS is intended to be a technology-forcing regulatory mechanism to drive reductions in emissions from major pollution-generating sectors. *See Sierra Club v. Costle*, 657 F.2d 298, 364 (D.C. Cir. 1981) ("[W]e believe EPA

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amounts or where we determined that a [best demonstrated technology] analysis would result in no control." 75 Fed. Reg. 54,996-97 (Sep. 9, 2010).

[95] S. Rep. No. 91-1196, at 17 (1970).

[96] *Id. at* 16.

does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible."); *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (The court "reject[ed] the suggestion of the cement manufacturers that the [Clean Air] Act's requirement that emission limitations be 'adequately demonstrated' necessarily implies that any cement plant now in existence be able to meet the proposed standards.") The D.C. Circuit has explained that as EPA fulfills its innovation-forcing mandate, the Agency should be forward-looking when determining what systems of emission reduction are available: "Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present."[97]

2. **New Source Performance Standards Have Played Key Technology-Forcing Roles in the Past.**

The Congressional Research Service (CRS) documented the technology-forcing function that NSPS have played in its report on the potential regulation of GHG sources under the Clean Air Act. The report notes that the flexibility inherent in the Administrator's authority to determine which technologies have been adequately demonstrated "has been used to authorize control regimes that extended beyond the merely commercially available to those technologies that have only been demonstrated, and thus are considered by many to have been 'technology-forcing.'"[98]

The CRS report focuses on the 1971 and the 1978 NSPS for sulfur dioxide (SO_2) emitted by coal-fired electric generating units as a prime example of the Agency incentivizing technology development and thereby facilitating ambitious emission reductions through NSPS. The 1971 NSPS required a 70% reduction in new power plant SO_2 emissions, on average, and could be met initially only by burning low-sulfur coal or by using an emergent technology known as flue gas desulfurization (FGD). When the 1971 utility SO_2 NSPS was promulgated, there was only one FGD vendor and only three FGD units in operation. The 1979 NSPS retained the 1971 emission standard but also required a 70-90% reduction in combustion emissions, depending upon the sulfur content of the coal. This requirement could then be met only by using an FGD device.

A history of the development of FGD devices (cited in the CRS report) further illustrates how much the SO_2 NSPS motivated the development of this technology:

> The Standards of Performance for New Sources are technology-forcing, and for the utility industry they forced the development of a technology

[97] *Id.*

[98] Larry Parker & James E. McCarthy, Cong. Research Serv., R40585, Climate Change: Potential Regulation of Stationary Greenhouse Gas Sources Under the Clean Air Act 12 (2009).

> that had never been installed on facilities the size of utility plants. That technology had to be developed, and a number of installations completed in a short period of time. The US EPA continued to force technology through the promulgation of successive regulations. The development of this equipment was not an easy process.
>
> . . .
>
> Chemical and mechanical engineers had never dealt with the challenges they faced in developing FGD systems for utility plants during this period. Chemical engineers had never designed process equipment as large as was required, nor had they dealt with the complex chemistry that occurred in the early FGD systems. Mechanical engineers were faced with similar challenges. While they had designed equipment for either acid service or slurry service, they typically had not designed for a combination of the two. Generally, equipment was larger than what they normally dealt with in chemical plants and refineries.
>
> It is an understatement to say that the new source performance standards promulgated by the EPA were technology-forcing. Electric utilities went from having no scrubbers on their generating units to incorporating very complex chemical processes. Chemical plants and refineries had scrubbing systems that were a few feet in diameter, but not the 30- to 40-foot diameters required by the utility industry. Utilities had dealt with hot flue gases but not with saturated flue gases that contained all sorts of contaminants. Industry, and the US EPA, has always looked upon new source performance standards as technology-forcing, because they force the development of new technologies in order to satisfy emission requirements.[99]

As can be seen in Figure 3, analysis of patenting activity further demonstrates the dramatic rise in control technology innovation in the U.S. that followed the 1971 SO_2 NSPS promulgation.[100]

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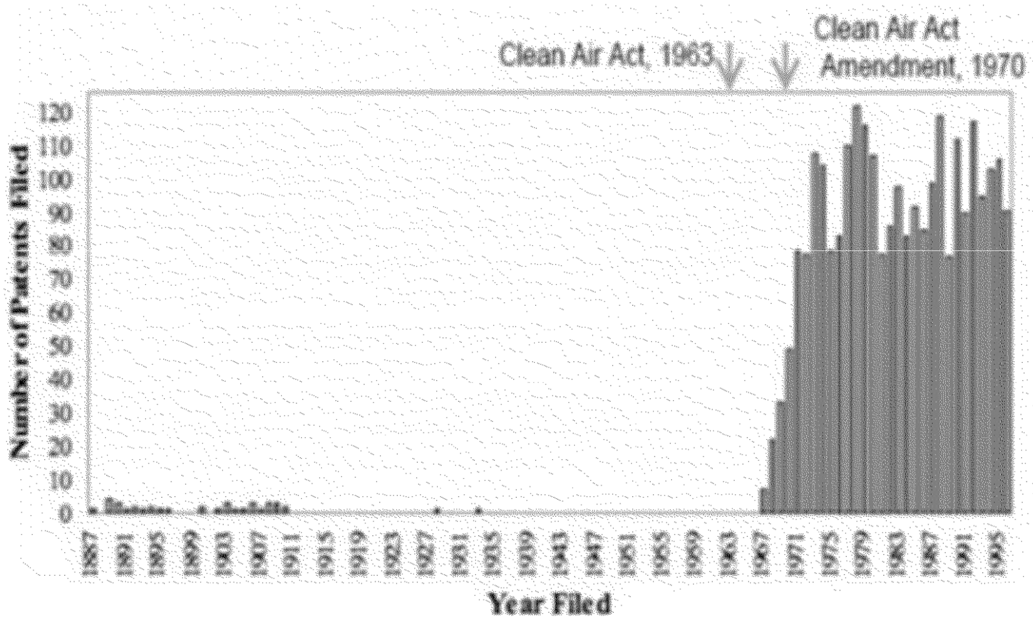
[99] Donald Shattuck et al., A History of Flue Gas Desulfurization (FGD) – The Early Years at 15, 3.

[100] M. Taylor, The Influence of Government Actions on Innovative Activities in the Development of Environmental Technologies to Control Sulfur Dioxide Emissions from Stationary Sources 211-12 (Jan. 2001) (unpublished Ph.D. thesis, Carnegie Mellow University) [hereinafter Taylor Ph.D.] (on file with author); *see also* ICF Consulting, The Clean Air Act Amendments: Spurring Innovation and Growth While Cleaning the Air 106-08, 118-20, 211-12 (2005).

Figure 3: U.S. Patents Relevant to SO_2 Control Technology as Identified with the Patent Subclass Method[101]



Thanks to these technology advances, when Germany subsequently implemented a program to control acid rain, 33% of the FGD systems installed were licensed from U.S. companies.[102] Researchers of this and similar regulatory initiatives have observed that stringent regulation is required to stimulate significant innovation in control technologies; neither weak regulation nor legislation supporting control technology research have this effect.[103]

The 1979 NSPS is a compelling example of both the flexibility of the Agency's authority under Section 111 and the efficacy of innovation-focused standards in incentivizing technology development.

3. **The "Best System of Emission Reduction" Language Is Broad and Easily Encompasses a Combined Cycle Turbine Design Burning Natural Gas.**

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[101] *Id.* at 107.
[102] *Id.* at 56, 131.
[103] *See id.* at 220; M. Taylor et al., *Control of SO2 Emissions from Power Plants: A Case of Induced Technological Innovation in the U.S.*, 72 Technological Forecasting & Soc. Change 697 (2005).

EPA emphasized as early as 1976 that BSER could encompass low-emission production methods.[104] In setting the smelter NSPS, the agency rejected the notion that BSER determinations must rely exclusively on emission control hardware:

> For some classes of sources, the different processes used in the production activity significantly affect the emission levels of the source and/or the technology that can be applied to control the source. For this reason, the Agency believes the 'best system of emission reduction' includes the processes utilized and does not refer only to emission control hardware. It is clear that adherence to existing process utilization could serve to undermine the purpose of section 111 to require maximum feasible control of new sources.[105]

The 1970 "best system of emission reduction" language that the agency interpreted is nearly identical to the current language, adopted in 1990.[106]

In today's electricity sector, coal- and combined-cycle gas-burning power plants—two systems of electricity generation—are largely functionally interchangeable in providing baseload and load-following generation.[107] Indeed, as EPA's proposal notes, the only new generation projected to be built to serve baseload and intermediate demand is from combined cycle natural gas plants.[108] In identifying BSER, EPA has an obligation to

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[104] *See* Standards of Performance for New Stationary Sources, Primary Copper, Zinc, and Lead Smelters, 41 Fed. Reg. 2332, 2333 (Jan. 15, 1976).
[105] *Id.*
[106] *Compare* CAA Amendments of 1970, PL 91-604, § 111(a)(1), 84 Stat. 1676, 1683 (1970) ("The term 'standard of performance' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.") *with* CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1) (2006) ("The term 'standard of performance' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.").
[107] 77 Fed Reg. at 22411.
[108] Courts have explicitly approved EPA's practice of taking into account industry trends when setting standards. *See National Lime Ass'n v. EPA*, 627 F.2d 416, 426 n.28 (D.C. Cir. 1980) ("It is expected that as supplies of natural gas and oil become more expensive or unavailable, all new kilns would be rotary lime kilns designed to burn coal."); Standards of Performance for New Stationary Sources: Lime Manufacturing Plants, 42 Fed. Reg. 22,506, 22,507 (May 3, 1977) ("[V]irtually all the new kilns that have been built

consider the substantial combustion emission advantages of combined-cycle natural gas as compared to coal-fired plants and to set the performance standard accordingly. The substantial cost advantages of NGCC further reinforce the reasonableness of NGCC as BSER. When considering two functionally interchangeable processes, not to set BSER based on the lower-emitting process, especially when that process is also less expensive, would fail to fulfill the statutory directives of CAA § 111(b) to maximize emission reductions considering cost and other relevant impacts.[109]

C. Legality and Appropriateness of the Alternative Compliance Option

The alternate pathway provided for coal plants is consistent with the NSPS program's technology-forcing purpose.

1. Designing an NSPS to Incentivize the Development of Low-Emitting Technologies Is Consistent with § 111.

Through the alternative compliance pathway EPA has allowed a path for carbon capture and sequestration technology to play a role in controlling CO_2 emissions from fossil-fuel-fired power plants—helping make investments in developing and deploying this technology secure. This regulatory certainty is what power sector participants have identified as the missing link in the development of CCS. In discussing the decision to stop moving forward with a broader deployment of CCS at its West Virginia Mountaineer plant, American Electric Power Chairman and CEO Mike Morris said: "Going forward without a carbon legislation or without an appropriate approach to carbon and its impact it was simply not able for us to go forward and continue that project. . . . We are encouraged by what we saw, we're clearly impressed with what we learned and we feel that we have demonstrated to a certainty that the carbon capture and storage is in fact viable technology for the United States and quite honestly for the rest of the world going forward."[110]

As noted above, the NSPS is intended to drive innovation in methods of reducing emissions. The *Sierra Club* court determined that legislative history reinforced its

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in the last few years have been of the rotary type. . . . [T]he present trend is to build and operate rotary kilns whenever possible.").

[109] While there is a cost advantage of natural gas, section 111 calls for the "best system of emission reduction" to be determined "taking into account the cost of achieving such reduction" and other pertinent statutory factors. 42 U.S.C. §7411(a)(1). The costs of a fuel neutral standard based on this best system, therefore, do not require a cost advantage but must not be unreasonable.

[110] American Electric Power Q2 2011 Earnings Call (July 29, 2011), CallStreet Raw Transcript.

interpretation of the statute that one of the purposes of NSPS is to "create incentives for new technology."[111] The court cited several examples from the legislative history about the CAA Amendments of 1977 in which legislators address technology-forcing portions of CAA § 111.[112] The House Committee Report, for instance, noted that "it is prudent public policy to require achievement of the maximum degree of emission reduction from new sources, while encouraging the development of innovative technological means of achieving equal or better degrees of control."[113]

The Senate Committee Report on the CAA Amendments of 1970 also clarified that "[s]tandards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources."[114] An emerging control technology used as the basis for standards of performance need not "be in actual routine use somewhere."[115] The D.C. Circuit, analyzing the Senate's intent, found that "[t]he essential question was [] whether the technology would be available for installation in new plants."[116]

The D.C. Circuit sanctioned the tailoring of an NSPS to incentivize the development of specific innovative, low-emitting technologies in *Sierra Club v. Costle*.[117] There, EPA declined to adopt a uniform requirement that all entities in the regulated category reduce SO_2 emissions by 90% because that requirement would have prevented some low-sulfur-coal facilities from using the new technology known as dry scrubbing.[118] EPA thought that it was important to "provid[e] an opportunity for full development of dry SO_2 technology."[119] The court found that, provided that EPA balanced the factors listed in the NSPS provision, designing the NSPS to incentivize new technologies was consistent with the text of the CAA.[120]

EPA's alternative pathway for coal plants serves this well-established technology-forcing purpose by providing regulatory certainty for CCS as an emerging control technology. As discussed above, the SO_2 NSPS served this purpose for scrubbers in the 1970s. The CRS report noted that the NSPS could play a similar role for deployment of carbon capture and sequestration: "The [SO_2 scrubber] example indicates that technology-forcing regulations can be effective in pulling technology into the market—even when there remain some operational difficulties for that technology. . . . As an entry point to

111 See *Sierra Club v. Costle*, 657 F.2d 298, 346-47 (D.C. Cir. 1981).
112 *See id.* at 346 n.174.
113 *Id.*
114 S. Rep. No. 91-1196, at 17 (1970).
115 *Id.* at 16.
116 *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).
117 *See Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981).
118 *See id.* at 343.
119 *Id.* at 327-28.
120 *See id.* at 346.

carbon capture deployment, a regulatory approach such as NSPS may represent a first step."[121]

EPA's alternative compliance pathway for coal plants is thus providing the very mechanism for CCS that power sector participants deploying CCS have called for, consistent with the court-affirmed Congressional intent that NSPS serve a technology-forcing role in order to drive down emission reductions.

2. EPA's Analysis of BSER Availability Should Be Forward-Looking and Is Owed Deference.

The thirty-year compliance framework for coal plants using CCS that EPA has proposed involves a forward-looking availability analysis. The courts have affirmed EPA's authority to make such projections. In *Portland Cement Association v. Ruckelshaus*, the court found that "[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry. . . . [T]he question of availability is partially dependent on 'lead time', the time in which a technology will have to be available."[122] Further, the court noted that "[i]t would have been entirely appropriate if the Administrator had justified the standards, not on the basis of tests on existing sources or old test data in the literature, but on extrapolations from this data, and on testimony from experts and vendors made part of the record."[123]

As discussed above, courts have properly deferred to EPA's analysis of the best systems of emission reduction available.[124] In *Sierra Club*, the court "on close questions [gave] the agency the benefit of the doubt out of deference for the terrible complexity of its job."[125].

3. NSPS May Alter Business As Usual.

By its very nature, technology forcing may prevent some actors from proceeding with business as usual, if business as usual would entail a lagging process that is more

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[121] Larry Parker & James E. McCarthy, *supra* note 4, at 19-20.
[122] *Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 391 (D.C. Cir. 1973).*
[123] *Id.* at 401-02. The standards challenged in *Portland Cement* were finalized after the Agency conducted testing at seven plants, which the D.C. Circuit found to be sufficient. *See Portland Cement Ass'n. v. Train*, 513 F.2d 506, 509 (D.C. Cir. 1975).
[124] *See Sierra Club v. Costle*, 657 F.2d at 343, 364 (incentivizing and forcing technology); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d at 391 (relying on cutting-edge technology).
[125] *Sierra Club v. Costle*, 657 F.2d at 410.

polluting, or would need greater investment to meet a standard, than a lower-emission technology. In setting NSPS for copper smelters, EPA explained that it could set a "single standard [that] would *effectively preclude* using a process which is much less expensive than the permitted process" so long as the total cost of the standard was reasonable.[126] This precedent demonstrates that "effectively preclud[ing]" a production method can be entirely consistent with reasonableness and economic achievability. Given the entirely reasonable cost of the standard proposed here and the enormous harm to Americans' health, safety, and environment caused by the pollution generated by uncontrolled coal-fired power plants, EPA was entirely justified – indeed, required – to set a standard that will require any new coal plant to be designed and operated in a manner that will make deeps cuts in the amount of harmful pollution generated.

4. **EPA Has Authority to Adopt Alternative Compliance Mechanisms.**

a. EPA Has Adopted Other Flexibility Mechanisms.

The provision of alternate compliance pathways is a familiar approach under § 111. As noted above, in Subpart GG of 40 C.F.R. Part 60, EPA established burning a particular type of fuel as one option for meeting the SO_2 emissions standard. The agency described that option as "an *alternative* SO_2 emissions limit."[127] The main limit set a numeric emission standard to be met at the stack, regardless of the fuel burned.[128] In essence, EPA provided an alternative compliance option that remains valid.

The 1981 *Sierra Club* decision provides another clear example of an alternative compliance option. At issue were the NSPS for EGUs finalized by EPA in June 1979.[129] The main standard required a maximum of 1.20 lbs SO_2/MMBtu and a 90% reduction from uncontrolled levels.[130] EPA, however, also allowed for an optional method of compliance—what the *Sierra Club* court called an "optional standard"—similar to the "alternative compliance option" in the proposed GHG NSPS.[131] The option provided that, if a fuel's potential SO_2 emissions were less than 0.60 lbs/MMBtu, the emission-reduction requirement decreased from 90% to 70%.[132] As a practical matter, the

[126] *See* Standards of Performance for New Stationary Sources: Primary Copper, Zinc, and Lead Smelters, 41 Fed. Reg. 2332, 2333 (Jan. 15, 1976) (emphasis added).
[127] Standards of Performance for New Stationary Sources: Gas Turbines, 44 Fed. Reg. 52,792, 52,792 (Sept. 10, 1979) (emphasis added).
[128] *See id.*
[129] New Stationary Source Performance Standards: Electric Utility Steam Generating Units, 44 Fed. Reg. 33,580 (June 11, 1979).
[130] *See id.* at 33,580.
[131] *Sierra Club v. Costle*, 657 F.2d 298, 316 (D.C. Cir. 1981).
[132] *See* 44 Fed. Reg. at 33,580

optional standard allowed low-sulfur-coal facilities to use dry scrubbing rather than wet scrubbing.

EPA's alternative compliance pathway for coal fits within this regulatory tradition.

b. Flexibility Mechanisms Have Been Judicially Approved.

In *Sierra Club v. Costle*, environmental petitioners argued that an NSPS's optional standard violated CAA § 111.[133] The court disagreed, relying § 111(b)(2), which authorizes EPA to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing . . . standards."[134]

Also of note, the *Sierra Club* court was more deferential to EPA when reviewing the optional standard than the main standard. The court did not ask if dry scrubbing could have served as an independent basis for the standard because it had already found that wet scrubbing was the BSER.

Instead, the court limited its analysis to whether EPA had a reasonable basis for its technical analysis of dry scrubbing. The court determined that "the support in the record for selecting 70% as the magic percentage for encouragement of dry scrubbing [was] less than overwhelming" but recognized that EPA was trying to encourage the development of dry scrubbing technology.[135] Because "it was reasonable for EPA to seek to encourage dry scrubbing and to be concerned with the effect of the NSPS on the future of the new technology," the court upheld the optional standard.[136]

As with the SO_2 NSPS's optional standard in *Sierra Club*, the alternative compliance option in the proposed GHG NSPS merits respect because it reasonably balances the relevant statutory factors required to be considered in establishing a standard of performance under the law as well as technical factors that are unique to the development of CCS technology.

D. CO_2 Emission Limits for Intermediate and Base-load EGUS

1. **EPA's Proposed CO_2 Emission Limits Are Too Lenient**

[133] *See* 657 F.2d at 316-17.
[134] CAA § 111(b)(2), 42 U.S.C. § 7411(b)(2) (2006); *see also Sierra Club v. Costle*, 657 F.2d at 319-20.
[135] 657 F.2d at 351.
[136] *Id.*

Joint Environmental Commenters agree with EPA's proposal to adopt a fuel-neutral standard for CO_2 emissions from base load and intermediate load electric generating units. We also agree that the final standard should be based on the best system of emission reduction achievable for natural gas combined cycle generation. Generation of electricity by use of natural gas combined cycle (NGCC) technology has been common for decades and, indeed, represents the most likely choice for new fossil fuel-fired generation over the next several decades. However, there is a substantial variation in performance of this type of technology that EPA's proposal fails to reflect. The ''best system of emission reduction'' (BSER) may not reflect the emissions performance of the worst performing unit that employs NGCC technology, but must be set at a level that reflects the best existing performers *and* improvements in performance that may be reasonably anticipated in the time frame over which sources subject to the standard are constructed. In other words, just as standards for new vehicles may be more demanding for later model years with more lead time, so too standards for power plants under Section 111(b) may require better performance of plants built in later years if supported by reasonable projections of technological improvements during this lead time.

In setting performance standards under section 111, EPA has made a consistent practice of examining existing sources to identify the best systems of emission reduction in use. In this case, the record does not indicate that EPA has performed a comparable analysis to support the proposed standard. Joint Environmental Commenters have undertaken an analysis of the available data and literature and conclude that a more stringent standard is technically and economically achievable. Based on our analysis, we recommend that EPA adopt a standard in the range of 825-850 lbs/MWh (net), rather than the 1000 lbs/MWh (gross) the Agency has proposed.

Joint Environmental Commenters urge that a more stringent standard than the one proposed is necessary to ensure that, in a time of historically low natural gas prices, developers of new EGUs choose the most efficient units available. The data on existing units demonstrates that developers do not always choose such units, even with higher natural gas prices. Given the urgent need to reduce carbon emissions from the entire electricity sector, a stringent standard is needed to minimize carbon emissions from NGCC units.

Within EPA's proposed category of intermediate load and base load fossil-fuel fired EGUs, NGCC units generally exhibit lower CO_2 emission rates than coal or oil-fired units or natural gas simple cycle units; but within the group of NGCC units there are clear distinctions in the emission reductions associated with differences in designs. Similar units, even similar units produced by the same manufacturer, show substantially different rates of CO_2 emissions.

The emission rates of some existing NGCC units are twice as high as the best performers. These differences are not serendipitous, but the consequence of deliberate decisions of the designers to incorporate features and systems that enhance combustion and generating efficiency. For example, the performance of NGCC units is improved when the manufacturer designs the turbines to operate at higher temperatures. For every 30 Celsius degree ("°C") rise in gas turbine firing temperature, the combined cycle efficiency increases by about one percent; an efficiency of 60 percent can be reached if the design operating temperature approaches 1500 °C.[137] Improved gas turbine efficiencies can also be achieved through the use of improved thermal coatings, closed circuit steam or water cooling of turbine blades, and use of nitrogen instead of steam as the diluent for reducing NO formation. The efficiency of the NGCC unit can be also substantially increased by using fully-fired heat recovery steam generator (HRSG) units, which have higher, but nonetheless reasonable, construction costs than partially fired or unfired HRSGs.[138] These techniques and the relative efficiency improvements that result from their use are well known, and are routinely offered by vendors as optional cost-effective upgrades to standard units.[139]

In addition to considering the demonstrated performance of the existing units with the best system of emission reductions, EPA is obliged to incorporate those performance improvements that can be reasonably anticipated. Over the past few years there has been an across the board effort by turbine manufacturers to significantly increase the efficiency of gas turbine design under full and part-load conditions in both simple and combined cycle mode.[140] New, more efficient models, not reflected in the performance data relied on by EPA, have recently been introduced or announced by vendors for entry into the market in the near future.

EPA assembled original equipment manufacturer (OEM) combined cycle performance specifications from Gas Turbine World.[141] This data set includes 89 combined cycle gas turbines that EPA concluded would be subject to the proposed standard if they were new. This data is included in the docket in a spreadsheet called "Gas Turbine Workbook" in a tab called "Combined Cycle." We agree these data are a reasonable starting point but note that they have been updated in the 2012 GTW Handbook.[142] This new edition represents the most up-to-date information available at

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[137] P. Chiesa and E. Macchi, Trans. ASME, Journal of Engineering for Gas Turbine and Power, v. 126, no. 4, pp. 770-85, 2004.

[138] See, Chase, D.L and Kehoe, P.T. GE Power Systems, *GE Combined-Cycle Product Line and Performance, p.3* http://physics.oregonstate.edu/~hetheriw/energy/topics/doc/elec/natgas/cc/combined%20cycle%20product%20line%20and%20performance%20GER3574g.pdf

[139] Id. at Table 14.

[140] See discussion in Gas Turbine World, 2012 GTW Handbook, pp. 6 -24.

[141] 2011 Performance Specifications, Gas Turbine World, 27th Ed., Available at: http://www.gtwbooks.com/GTW-Archive.html for $55.

[142] Gas Turbine World, 2012 GTW Handbook, v. 29 ("2012 GTW Handbook")

this time, and EPA should consider it in making its final decision. Accordingly, EPA must update its analysis to incorporate this newly available information.

These Gas Turbine World Handbook performance specifications are based on "new and clean" gas turbine ratings for net plant output and base load operation of a standardized reference plant, including losses and auxiliary loads, on natural gas fuel, at 59°F, sea level, and reasonably realistic steam cycle conditions.[143] Thus, they do not reflect the range of operating conditions that will be experienced by future NGCC facilities. However, it should be noted that manufacturers also employ conservative factors in establishing performance specifications, since they are subject to damages if the units do not perform as specified. EPA adjusted the Gas Turbine World performance specifications to account for various factors it assumed were not included in the specifications.

EPA's adjustments included:

- 5 percent increase in design heat rate to account for part-load conditions;
- 1 percent increase in design heat rate to account for operation at non-design ambient temperatures;
- 5 percent increase in design heat rate to account for degradation in performance over the life of the facility;
- 125 Btu/kWh increase in heat rate to account for increased pressure drop from post-combustion controls, e.g., SCR.

These adjustments amount to an increase in the net heat rate of nearly 13 percent.[144]

Joint Environmental Commenters agree that some correction to design data is needed to address certain operational variables. However, in some instances EPA's proposed corrections are not supported by information in the record and are either overly large or entirely unwarranted. Finally, the Gas Turbine World Handbook points out that the performance specifications are conservative and that better performance is possible – as much as a 1.5 percent gain in overall plant efficiency – for higher, but none the less reasonable, costs.[145] Thus, in our opinion, the "best system of emission reduction" emission rate reflected in the proposed standard is significantly higher than is warranted.

[143] 2012 GTW Handbook, p. 64.
[144] 125 Btu/kW is slightly less than two percent of the heat rate of the better performing units.
[145] 2012 GTW Handbook, p. 64.

2. **The EPA Temperature Adjustment Is Not Warranted**

EPA increased the ISO heat rate by 1 percent to account for operation at non-design ambient temperatures. The OEM design specifications are based on 59° F. We agree that an increase in ambient air temperature reduces gas turbine power with a proportionate increase in heat rate and CO_2 emissions. However, this adjustment proposed by EPA is inconsistent with BSER, since inlet cooling is available and routinely used to increase power output of gas turbines. Inlet cooling improves efficiency during high ambient temperature operation of 5 percent to 25 percent of gas turbine nameplate rating, reducing fuel consumption and hence reducing CO_2 emissions.[146] A number of inlet cooling technologies are commercially available, including wetted media, fogging, wet compression, and chilling. In fact, inlet cooling is used to reduce inlet temperatures below 59 °F, thus increasing efficiency to better than ISO conditions. EPA should ascertain the extent to which any adjustment is warranted where inlet cooling technology is employed. Based on the information in the open literature reviewed by Joint Environmental Commenters, the need for an adjustment for ambient temperature has not been demonstrated. This conclusion is supported by EPA's in-use CAMD data discussed below.

3. **The EPA Performance Adjustment Is Overestimated**

Degradation is an important factor to be considered, as the heat rate of the facility will gradually deteriorate between overhauls. EPA has asserted that "although generally estimated at less than 3 percent over the life of the facility", it would "conservatively" apply a 5 percent increase in heat rate due to degradation to account for adverse conditions and different turbine designs. Since EPA acknowledges that this figure is substantially larger than supported in the record, it may not be used to set the standard for new units. Our review of the literature indicates that 5 percent is a significant overestimate given maintenance practices that are widely used and known to improve output (and revenue) and indeed, that 3 percent is likely to be too high for newly designed and constructed units that employ efficient designs.[147] Published

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[146] Gas Turbine Inlet Cooling. Scope, Cost and Performance for New and Retrofit Power Plant Projects, 2010 Gas Turbine World Handbook, pp. 32 - 39. This article reports CO2 emissions from a combined cycle plant using turbine inlet cooling of 700 lb/MWh (Fig. 6). See also: D.V. Punwani, Turbine Inlet Cooling: Increased Energy Efficiency & Reduced Carbon Footprint Aspects for District Energy Systems, June 13-16, 2010, http://www.turbineinletcooling.org/News/Avalon_IDEA2010June.pdf.

[147] See, e.g., I.S. Diakunchak, Performance Deterioration in Industrial Gas Turbines, <u>Journal of Engineering for Gas Turbines and Power</u>, v. 114, April 1992, pp. 161-168 (1%); S. Can Gulen and Sal Paolucci, Real-time On-line Performance Diagnostics of Heavy-duty Industrial-gas Turbines, Transactions of the ASME (2%), Available at: http://www.thermoflow.com/WALK_GTEYE/ASME_2000-GT-

industry information asserts that good maintenance practices, including frequent off-line water washing, reduce both the amount of performance degradation and the rate of performance degradation.[148] In determining the appropriate factor for performance degradation, EPA needs to consider far more detailed information than it has to date and ascertain the extent to which top-performing units – including units with better initial designs and units that employ appropriate maintenance practices –experience the assigned degradation factor. We note that the Gas Turbine World Handbook relied on by EPA for much of its proposal asserts that the performance degradation between overhauls ranges between 2 and 6 percent. In the absence of specific credible information that documents the use of a higher figure, BSER requires the use of the lower end of this range.

4. **The Pollution Control Device Performance Impact Is Overestimated**

EPA has assumed a decrease of 125 Btu/kWh in the adjusted heat rate to account for increased pressure drop from post-combustion controls, such as SCR. However, no support is provided for this estimate – EPA simply states that it has applied this correction factor. Further, this estimate is demonstrably too high.

The emissions of NO_x are commonly controlled in NGCC plants by installing SCR catalyst in a spool piece in the HRSG. This typically results in an increase in backpressure of about 2 inches water gauge. In some states, CO and VOCs are additionally controlled by installing oxidation catalyst in the spool piece, especially in areas that are nonattainment for ozone. The addition of catalyst in the flue gas path for these post-combustion controls increases the backpressure by about 3 inches of water gauge total. This increase results in a loss in power output, increasing the heat rate. We agree with EPA that an adjustment is warranted as the OEM performance specifications assume no pollution controls. However, we believe that EPA's proposed pollution control heat rate penalty of 125 Btu/Kwh is unsupported and can be shown to be too high.

Joint Environmental Commenters estimated the impact of a 3 inch increase in HRSG backpressure for 17 of the most common NGCC plants using Thermoflow's power plant modeling software, GT Pro and GT Pro Macro. Our analyses assumed a base HRSG backpressure of 19 inches water, corresponding to maximum backpressure during duct burner power augmentation; ambient pressure of 14.7 psia (sea level); 59°F, and 60 percent relative humidity. These analyses, included in Appendix Bindicate that an increase in HRSG backpressure of 3 inches water gauge due to SCR plus oxidation catalyst in the HRSG gas path would increase the gross LHV heat rate by 24 to 44

312_ThermoflowGTEYE.pdf; J. Petek and P. Hamilton, Performance Monitoring for Gas Turbines, Orbit, v. 25, no. 1, 2005; Emerson Process Management, Gas Turbine Engine Performance, January 2005.

Btu/kWh and the net LHV heat rate by 26 to 47 Btu/kWh. This is nearly a factor of three lower than assumed by EPA and should be employed in the absence of model specific testing.

In sum, where EPA has proposed to correct the manufacturer's documented plant performance at ISO conditions by a factor of 11 percent plus 125 Btu/Kwh, Joint Environmental Commenters believe that this correction factor has not been shown to be larger than 7-8 percent plus 50 Btu/kWh.

5. **The Partial-Load Adjustment Should be Reexamined**

The EPA increased the ISO design heat rate for all design configurations by 5 percent to account for part-load conditions but provides no specific support for its choice.[149] This figure appears to be based on worst-case conditions and does not consider improved performance achieved with the best partial-load controls and most efficient turbine models that would satisfy BSER. Gas turbines with higher design performances, for example, exhibit superior part load performance.[150] BSER should be established based on gas turbines with higher design performances and the best available part-load control. We further note that the global growth in wind power and solar generation has spurred the introduction of more flexible gas and steam turbine designs for combined cycles capable of fast startup and ramping, operational flexibility, and better part-load efficiencies.[151] Thus, we believe a 5% increase in heat rate for part-load operation for new units has not been substantiated and that EPA should consider, based on an examination of the available data and literature, including the Kim paper cited herein, whether a lower percentage increase is appropriate under the best system of emission reduction analysis. It may be possible to develop a more reasonable estimate of part-load performance degradation that can be calculated with simple algorithms (that can be set up in an Excel spreadsheet) and urge EPA to consider this approach.[152]

6. **Existing Unit Emission Rates Are Commonly Lower Than EPA' Proposed Standard**

[149] 4/12 EPA Memo ("We selected a 5 percent heat rate increase relative to the design rate to account for part-load conditions.").

[150] Kim 2004, p. 71.

[151] 2012 GTW Handbook, p. 46.

[152] S. Can Gülen and Joseph John, Combined Cycle Off-Design Performance Estimation: A Second-Law Perspective, Proceedings of ASME Turbo Expo 2011, June 6-10, 2011.

Figure 1 shows the emission rates from the units in EPA's data set, the EPA proposed limit and Joint Environmental Commenters recommended alternative of 825-850 lbs/MWh, all expressed as net emissions. Note that approximately one-half of the existing units have already met the recommended alternative limit. The recommended alternative limit would require more efficient designs than, reflected in the performance data in EPA's data set, while EPA's proposed limit would only have affected 15 percent of the theoretical "existing units" in that data.

While Joint Environmental Commenters agree that EPA should consider the design information provided by the Gas Turbine World Handbook, the agency should also recognize that vendor performance guarantees are necessarily conservative, as the vendor may be liable for damages if the promised performance is not achieved. EPA has at its disposal a wealth of CO2 emissions data that sources have been reporting pursuant to the CAA's Acid Rain Program. These data provide an additional source of information that reflects the actual, rather than theoretical, emissions of the leading systems of emission reduction. Moreover, EPA has traditionally relied on in-use testing to assist it in identifying BSER limits. However, we note that in this case, data for existing units does not necessarily establish BSER because it is based on outdated turbine models that will be replaced by more efficient models in the near-term. This anticipated improvement in efficiency and attendant reduction in CO_2 emissions should be addressed in establishing BSER. The CAMD data for existing units represent a ceiling which the emission rate standard for new units should not exceed.

While we recognize that the lack of unit capacity data in the CAMD data file[153] makes use of that information difficult for purposes of determining the size of the unit, the CAMD CO_2 emission data have been collected in much the same way that EPA's proposed standard will be enforced. It therefore should be no less accurate than the information that will be used to enforce the standard. It should also be noted that these units have experienced in-use variation in temperature, altitude and performance degradation with time, and so incorporate the factors that EPA assigns to manufacturers' performance specifications. Figure 1 sets out the Performance data reported by EPA[154] for the 73 units ("EPA Data Set") converted from gross to net emissions by application of a 3 percent correction factor. We have also added lines that represent EPA's proposed 1000 lb/MWh limit (gross) on a net basis and a more reasonable limit of 825 - 850 lbs/MWh based on the best performers in this data set.

Figure 1. Unit Emission Rates for Combined Cycle Units – EPA Data Set

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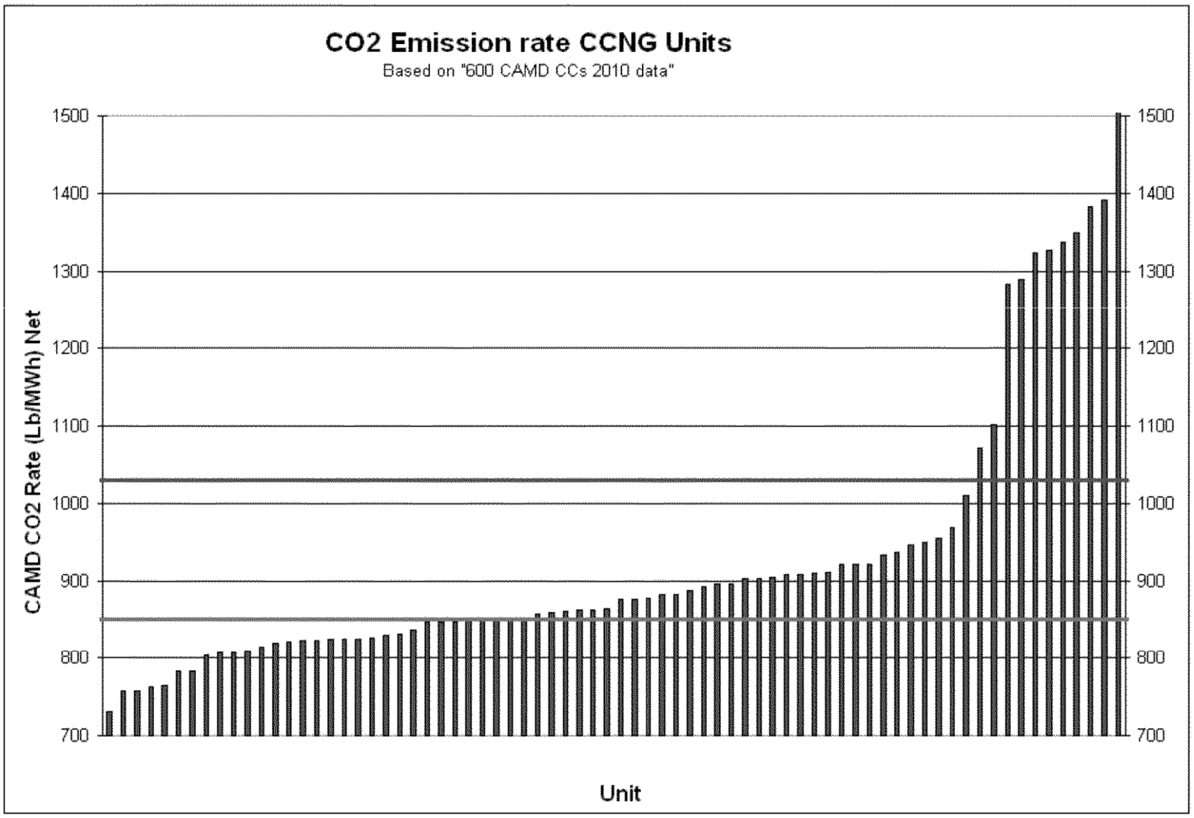
[153] The capacity data are from information collected and maintained by the Energy Information Administration (EIA).

[154] Memorandum from OQAPS to EGU NSPS Docket, *Design Data for New Combined Cycle Facilities*, Attachment Entitled "Gas Turbine World Performance Specifications (Apr. 12, 2012), Document ID No. EPA-HQ-OAR-2011-0660-0068



7. In Service Emissions Data Show That EPA's Proposed Limits Are Too Lenient

Table 1, below, lists all identified units that commenced operation since 2005[155], where the highest annual average CO_2 emission rate during the period from 2006 to 2011, on a net basis, is less than 850 lb/MWh.[156] As identified in Appendix A, certain data were excluded as outliers. The gross emission rates were converted to net by applying a 3 percent conversion factor, but no adjustment is made for load,

[155] We anticipate submitting a supplemental comment including emissions from such units that commenced operations at an earlier date.

[156] These data generally reflect operations in the first year where the HRSG may not yet have been operating. If the "outlier" data are included, the average of the top 10 units increases slightly to 807 lb/MWh (net) and the number of existing units that have demonstrated an ability to comply with a standard of 850 lb/MWh is reduced to 20. We have also excluded the Kleen Energy Center and Jack County units, where substantial variability in the data prevented us from ascertaining the representative high emission rate, and the Sand Hill Energy Center, where questions concerning the reported emission rate (603-655 lb) are as yet unresolved. Where less than a full year's data is reported, all available data was used.

temperature, NOx controls or decay in performance over time as these are reflected in the data itself. These units include units with different in-service dates, some with NOx controls, some in warm climates (many are in MS and FL, some at low altitudes (Astoria, 3 feet), some at high altitudes (Lakeville, 4500 feet) and with varying loads (as shown in the underlying data on gross CO2 emissions). As Table 1 shows, there were 30 units in the data base whose highest reported annual emissions were below 850 lb/MWh (net). The average of the highest reported annual emissions of this group is 817 lb/MWh (net). The average of the highest reported annual emissions of the top 10 performers is 791 lb/MWh (net).

Table 1 – Highest Reported Annual Average CO_2 Emission Rate – 2006 -2012 (Units < 850 lb/MWh(net)

FacilityID_ORISPL	Facility Name	State	UnitID	CO2 Emission rate (gross)	CO2 Emission Rate (net)
55375	Astoria Energy	NY	CT2	741	763
7845	Lagoon Creek	TN	LCC1	743	765
56237	Lake Side Power Plant	UT	CT01	766	789
56237	Lake Side Power Plant	UT	CT02	767	790
56031	Fox Energy Company LLC	WI	CTG-1	768	791
7845	Lagoon Creek	TN	LCC2	775	798
55375	Astoria Energy	NY	CT1	778	801
56407	West County Energy Center	FL	WCCT3C	778	801
55853	Inland Empire Energy Center	CA	1	780	803
56407	West County Energy Center	FL	WCCT3A	781	804
56407	West County Energy Center	FL	WCCT3B	781	804
55230	Jack County Generation Facility	TX	CT-4	783	806
55694	Quantum Choctaw Power, LLC	MS	AA-002	790	814
710	Jack McDonough	GA	4A	802	826
7082	Harry Allen	NV	**6	803	827
7082	Harry Allen	NV	**5	804	828
56407	West County Energy Center	FL	WCCT1A	806	830
564	Curtis H. Stanton Energy Center	FL	CCB	807	831
55694	Quantum Choctaw Power, LLC	MS	AA-001	810	834
56407	West County Energy Center	FL	WCCT1C	811	835
55853	Inland Empire Energy Center	CA	2	811	835
56407	West County Energy Center	FL	WCCT2B	811	835
56234	Caithness Long Island Energy Center	NY	0001	812	836

56407	West County Energy Center	FL	WCCT2C	815	839
56407	West County Energy Center	FL	WCCT2 A	816	840
2720	Buck	NC	12C	816	840
2720	Buck	NC	11C	816	840
56407	West County Energy Center	FL	WCCT1B	817	842
621	Turkey Point	FL	TPCT5B	824	849

These data incorporate substantial allowances for variability in performance as they are based on the highest annual average reported for each of these units from 2006-2011. No further allowance is called for. We anticipate that industry commenters may make broad arguments based on anecdotal information that further allowances are needed, for example, because of increased emissions from supplemental firing (duct burners). Those emissions are included in the data, but in the event that EPA is persuaded by such arguments, we offer below a means of addressing duct burners to accommodate such variability in annual CO_2 emission rate as might be occasioned by the use of these devices. These data, along with the performance specification data discussed earlier, clearly establish that the emission rate standard for new units should be no greater than a range of 825 -850 lb/MWh

8. **Small combined cycle unit emission rates**

EPA proposes a single CO2 standard for all affected units, regardless of the size of the facility or year of introduction of the turbine model. As a result, the performance data reflecting the very smallest of the **existing** NGCC designs, the 25 MW unit models, appear to have driven the selection of the proposed standard. There are two major problems with this approach: (1) BSER is not for existing models but rather new sources, and (2) it fails to recognize that the biggest plants that emit most of the CO2 currently employ the most efficient techniques and designs. The efficiency of combined cycle units is largely a function of gas turbine operating temperature; the use of enhancement techniques, such as inlet air cooling; and the use of fully fired HRSGs. There is nothing in the laws of physics that prevents smaller NGCC units from achieving the efficiencies of larger units. However, the Gas Turbine World Handbook data reveals that small units generally had efficiencies less than 55 percent while the better performing larger units had efficiencies of 59 to 60 percent.

As demonstrated earlier, NSPS standard setting is intended by Congress to drive technology transfer. Joint Environmental Commenters believe EPA should set a standard that drives this segment of the sector to develop smaller units with the same efficiencies as the larger units available today. At a minimum, EPA may not allow the theoretical existence of a potential market for a few small units to serve as a basis for setting a standard that is overly lax when applied to the larger units that are more likely to be responsible for most of the emissions from the category. To the extent that EPA is concerned that smaller units may not be able to meet the same limits as larger units, EPA should establish a size-based subcategory, as it has in other rules, and set a separate limit for smaller units.

We note that EIA data cannot be used to identify these small units as the EIA data report only the capacity of the combustion turbine for some of the smaller units and identifies several large (275 MW) units as less than 100 MW. Figure 2 lists all units that we have identified within the CAMD database for which the combined cycle unit capacity is 130 MW or less.

The Roseville Energy Center units are listed in CAMD as 42 MW units. The Roseville units appear to be the lowest emitting small combined cycle units in the CAMD data base. The reported annual emission rate for these units for the years 2006-2012 ranges from 877-926 lb/MWh on a gross emissions basis. If we assume that this unit is the benchmark for a small NGCC emission standard and apply a 3 percent conversion factor to the highest years' emissions the resulting limit for small NGCCs would be 954 lb/MWh (net). This difference in performance is consistent with the 2010 Gas Turbine World data on efficiencies, where small units generally had efficiencies less than 55 percent while the better performing larger units had efficiencies of 59-60 percent.

Table 2 displays the highest reported annual average emission rate (gross) and the highest reported emission(net) for each of the small units that we have been able to identify. Thirteen of these 15 units would have complied with EPA's proposed 1000 lb (gross) emission limit but none of these units would have met the 825-850 lb (net) range recommended above.

Table 2. Small combined cycle emission rates

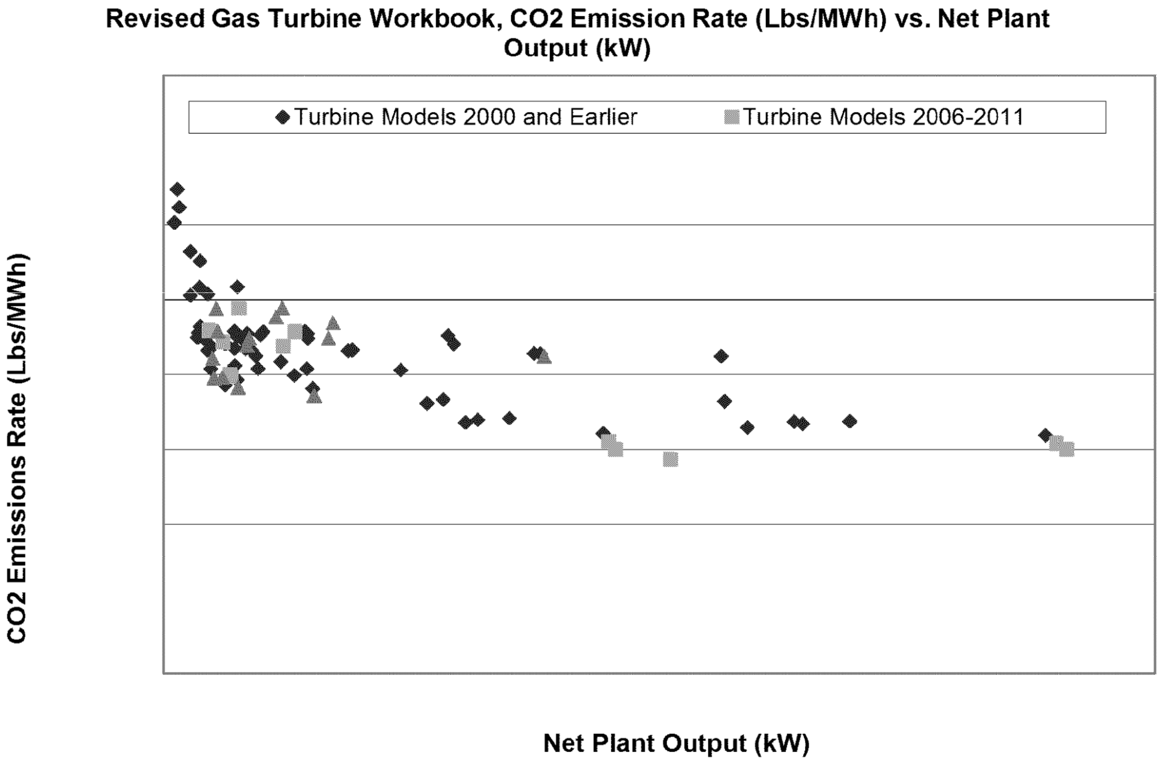
Column1	**Column2**	**Column3**	**Column4**	**Column5**
Name	Unit ID	High CO2 Rate (Gross) From Period of Observation	Highest Reported CO2 emission rate (net)	Combined Cycle Block Capacity
Sacramento Power Authority	1	863	889	172
Frederickson	F1CT	911	938	137
Roseville	CT001	922	950	160
Roseville	CT002	926	954	160
Raesfeld	PCT2	937	965	154

Raesfeld	PCT1	941	969	154
Carson Cogen	D1	959	988	55
Indeck Corinth	1	963	992	128
Pinelawn	00001	974	1,003	80
L'Energia	2	977	1,007	82
Dighton	1	984	1,014	169
Bluffview	CTG-1	986	1,015	60
Arapahoe	CT6	994	1,024	150
Arapahoe	CT5	1,016	1,046	150
Indeck Olean	1	1,043	1,074	79

The Gas Turbine World unit performance specifications show a substantial number of potential small combined cycle designs where the demonstrated emission rate at ISO conditions is at or below 900 lb/MWh. See Figures 2 and 3.[157] With the application of reasonable factors to account for operation at non-ISO conditions, an emission limitation of 1000 lb/MWh (net) appears to be attainable by these units. If EPA determines that subcategories by size are justified, the data demonstrate that the "cut point" in capacity between large and small units should be somewhere between 150 MW and 200 MW. Further analysis would be required to identify where, within this range, the subcategories should be divided.

Figure 2

[157] See also Appendix C.



9. **EPA Should Adopt a Net Electrical Output Standard**

EPA states that its proposed standard is in pounds of CO_2 per MWh of electricity produced on a gross basis. 77 FR 22394, 22398, 22436. However, our review of EPA's calculations that arrived at the 1000 lb/MWh standard indicates they were made and are reported on a net basis and mischaracterized in the rulemaking preamble. These calculations are reported in the spreadsheet, “Gas Turbine Workbook" in a tab called "Combined Cycle."

We note that the ISO performance specifications relied on by EPA are routinely reported on a net electrical output basis and that EPA has proposed that the CO_2 emission limit be based on a gross electrical output basis. Joint Environmental Commenters recommend that the final standard be established on a net electrical basis and thus would not make further adjustments to the design-based calculations. However, should EPA decide to promulgate a standard based on gross electrical output using the net heat rates used to develop the draft standard, EPA must then convert the net electric output-based calculations to a gross electrical output basis. We recommend the generally accepted conversion factor of 3 percent. That is, heat rates on a gross electric output basis should be assumed to be 3 percent lower than the heat rates reported by Gas Turbine World on a net electric output basis.

Joint Environmental Commenters strongly recommend that the standard be based on emissions per net generation. A net emission standard (1) more accurately reflects what is to be regulated; (2) can be implemented in a simple and straight forward fashion (especially for new units); (3) provides an appropriate incentive for minimizing parasitic loads, and (4) is needed to accomplish the fuel- neutral goal of the standard and ensure that actual emissions from CCS coal-fired units do not exceed the level of emissions from BSER NGCC units. The net v. gross correction is relatively small for natural gas units (3 percent) but large and presently uncertain for CCS coal units. Enforcement of a standard based on net generation is relatively straightforward. The CO_2 measurement procedure is unchanged; but the measurement of the amount of electricity occurs at the bus bar or "delivery point" at the plant where ownership of the energy changes hands rather than at the generator itself.

The difference between of a gross and net generation standard is the treatment of emissions associated with the operation of auxiliary equipment, such as a scrubber, or in this instance the CCS process equipment. With a net generation standard, 100 percent of the real world emissions associated with generating the electricity that serves the public are measured and subject to the standard. Under a gross generation standard, that portion of the real world emissions that is associated with operating the CCS process equipment would be ignored. While the difference between net and gross generating capacity is quite small (3 percent) for a CCNG unit, it may be far larger (perhaps on the order of 30 percent) for coal-fired CCS units. If a CCS plant emits at the rate of EPA's proposed standard of 1000 lbs/MWh on a gross basis, but 30 percent of its power is used to run the CCS system, then its net output is only 0.7 MWh and so its emission rate per MWh would be 1000 lb/0.7 MWh or 1428 lb/MWh. In such a case, 428 lb/MWh of real world emissions would be ignored. In the case of a NGCC plant operating at a 1000 lb/MWh (gross) emission rate, 3 percent of its power is used to meet the needs of the balance of the plant and so the net output to the grid would be 0.97 MWh and its emission rate per MWh would be 1000 lb/0.97 MWh or 1031 lb/MWh. Joint Environmental Commenters submit that it is inappropriate to consciously ignore any real world emissions for no stated reason and submit that the extremely large difference in impact on units using different fuels is inconsistent with the stated fuel neutrality of the proposal.

While EPA has determined that NGCC and not CCS technology is BSER, we note that CCS equipped coal-fired units can meet both the EPA proposed limit on a net basis and the more protective net limit suggested by the Joint Environmental Commenters. In order to comply with a net emission limit of 1000 lb a coal-fired power plant with uncontrolled emissions of 2000 lb/MWh would have to employ a CCS that was 65 percent effective. A 70 percent effective CCS unit would be needed to meet our recommended alternate limit while a 79 percent effective CCS unit would be required to achieve the 600 lb/MWh limit proposed by EPA in its 30 year compliance option. Each of these capture rates have been shown to be achievable.[158] EPA should also ensure that the energy consumed by pre-combustion techniques, such as coal gasification, for CCS is properly accounted for.

10. **Duct Burners**

EPA has corrected for the reduction in efficiency associated with less than full load operation, but has not addressed the issue of the increased rate of emissions associated with the use of duct burners to serve peak power needs. We believe that the use of duct burners is embedded in the data and is not significant in terms of affecting the annual CO_2 emission rate. However, the specific emissions associated with the use of duct burners in the publicly available data are difficult to disaggregate. Joint Environmental Commenters anticipate that industry commenters may argue that the use of duct burners justifies a higher emission standard than is suggested by the performance specifications relied on by EPA or by CAMD data. EPA should not accept broadly based or anecdotal arguments to support such assertions, but should require credible, comprehensive data. The EPA should also investigate high efficiency duct burners. While we doubt that such data will be forthcoming, if sufficient factual information is presented to support such arguments, we suggest that, rather than raising emission limits for all units, EPA treat emissions from duct burners as peaking emissions, subject to the hourly limitations recommended in this comment for other peaking units, and not included for purposes of determining compliance with the emission limits for intermediate and base-load units. We believe that this could be accomplished by measuring the amount of natural gas consumed by the duct burners and applying the CO_2 emission factor of 117 lb CO_2/MMBtu and by measuring the increased generation that results from the use of the duct burners. Both the increased generation and the increased CO_2 would be subtracted from the annual emission calculation.

11. **Summary of Comments Regarding CO_2 Emission Limits**

1. We support a fuel-neutral, single category for all fossil fueled EGUs, with subcategories based on the function of the unit either as base load /intermediate-load unit or as a peaking unit.
2. EPA should identify the best system of emission reduction for this category. As a matter of engineering, this will require identifying the BSER for natural gas units, since they are generally lower emitting than coal or oil-fired units.

[158] Some would maintain that the energy penalty for CCS is "only" 20 percent which changes the emission rates but not the underlying issue.

3. BSER is to be established on what is achievable, not necessarily what has been done in the past. An emission limit that virtually all units constructed in the past six years can meet does not represent BSER.
4. At the very least, BSER should be no higher than the emission rate achieved by the average of the best performing existing combined cycle natural gas units.
5. Both (1) the design specification information (after applying reasonable factors for load, age, temperature and altitude) and (2) the in-service emissions data for the best performing units demonstrate that the emissions limitation for new intermediate and base load units should not be greater than 825-850 lb/MWh (net).
6. We strongly recommend the use of net generation rather than gross. A net emission standard (1) more accurately reflects what is to be regulated; (2) can be implemented in a simple and straight forward fashion (especially for new units); (3) provides the appropriate incentive to minimize parasitic loads; and (4) is needed to accomplish the fuel- neutral goal of the standard and ensure that actual emissions of CCS coal-fired units do not exceed the level of emissions from BSER NGCC units.
7. We anticipate that industry commenters may argue that small combined cycle units cannot meet either the limits proposed by EPA or the more stringent limits recommended by environmental commenters. At present the record does not support such an argument given that the same technologies that reduce the emission rates of larger units could be incorporated into smaller units. However, to the extent that EPA agrees with comments concerning small units, we recommend that EPA establish a separate BSER limit for units 150-200 MW or less, rather than relaxing the standard for the more common and more efficient larger units which emit the majority of the CO_2. Based on the several sets of information available to EPA, we do not believe that a limit greater than 950 – 1000 lb/MWh (net) is warranted for these smaller units.
8. While we agree that peaking units serve a different functional purpose, they can contribute significant greenhouse gas emissions. We recommend that EPA expeditiously commence a rulemaking establishing a standard for these units.
9. We anticipate that industry commenters may argue that units that employ duct burners to a large extent cannot comply with either the limit proposed by EPA or the more stringent limits recommended by environmental commenters. We note that the emissions from these devices are included in the reported emissions data and so should already be accounted for. Should submissions from industry to the record in this rulemaking demonstrate otherwise, we recommend treating both the generation and the emissions associated with the use of these devices as peaking unit emissions, which, as a matter of function and engineering design, they are.

E. 30 Year Compliance Option

Besides the basic 1000 lbs CO2/MWh standard, EPA proposed a separate 30 year averaging compliance option for coal- and petroleum coke-fired EGUs adopting CCS. 77 Fed. Reg. 22,406. This option includes two phases of emissions limitations that, over 30 years, would yield a 1000 lbs CO2/MWh cumulative average. EPA proposed to allow a

10 year first-phase, with the emissions limit set at 1800 lbs CO2/MWh. For the remaining 20 years, the source would have to meet a limit of 600 lbs CO2/MWh. The higher limit may be reached by a number of currently available coal technologies, and the lower limit may be reached by those technologies with the addition of CCS. EPA also proposed to allow sources to seek approval for alternative 30 year timelines with shorter (but not longer) periods of operation without CCS, and with other corresponding two-phase emission limits averaging to 1000 lbs/MWh over 30 years (so long as the first-phase limit does not exceed 1800 lbs/MWh).

These numbers should be revised downward to comport with the lower standard we recommend. For example, if EPA sets an annual standard at 825 lbs CO2/MWh, then plants using the 30 year compliance option should be required to achieve emissions of 1625 lbs/CO2 MWh during their first ten years of operation and emissions of 425 lbs CO2/MWh for the next 20 years.

F. A More Stringent Standard Is Economically Achievable

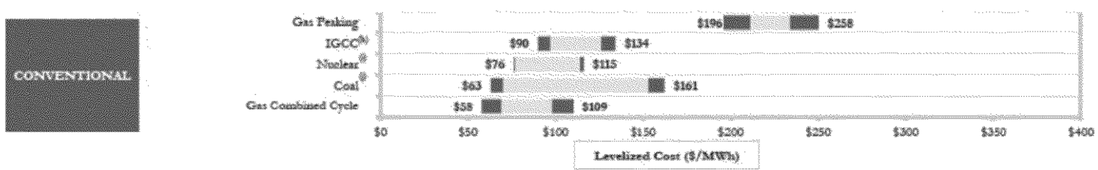
EPA correctly concludes that setting an NGCC-based BSER will not impose unreasonable (or even significant) costs upon the industry. *See* RIA at 5-15. The D.C. Circuit holds that considerations of economic achievability may weaken an NSPS only in highly exceptional circumstances. *See Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975) ("Portland Cement II") (NSPS may be made less stringent in response to economic considerations only "where the costs of meeting standards would be greater than the industry could bear and survive…"); *Lignite Energy Council*, 198 F.3d at 933 (EPA's standards will be upheld unless environmental or economic costs of using a technology are "exorbitant"). Here, the EPA's proposed standards are squarely within the bounds of these principles on economic achievability. The Agency's decision to set an emission limit based on NGCC plants is backed up by a thorough and reasonable analysis of the fossil fuel-generation industry's near-term future.

As EPA correctly concludes, "all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future." 77 Fed. Reg. at 22,413. It is simply not economic to proceed with these plants in a time of low electricity demand and low natural gas prices. *See id.* EPA observes correctly in the RIA that, consistent with these trends, the Energy Information Administration (EIA)'s Annual Energy Outlook for 2012 forecasts no new unplanned coal capacity through 2020. RIA at 5-5. EIA's most recent Electric Power Monthly report confirms that this trend continues. As of April 2012, *none* of the 4844 MW of the new units to come online are coal-fired; instead, new capacity additions are largely in renewable power or natural gas. EIA, *Electric Power Monthly May 2012* at Table ES3.[159] Conversely, retirements to date have been predominantly coal-fired units. *See id.* at Table ES4. Because the industry is already

[159] Attached as **Ex. 37** *supra,* at 6.

constructing NGCC plants, rather than coal plants, solidifying this economic trend with the NSPS will impose few, if any, additional costs.

Industry-wide levelized cost figures compiled by independent analysts also support EPA's analysis. The most recent (2011) edition of Lazard's Levelized Cost of Energy Analysis,[160] a widely-used reference, shows that even high-end values for the levelized cost of NGCC, which assume very high fuel prices, still fall at or below the mid-range levelized cost of coal generation. With lower fuel prices, the levelized cost of NGCC falls below the bottom end of coal unit costs.



Further, as we discuss in detail above, new large NGCC plants are being constructed at carbon emissions efficiencies substantially greater than 1000 lbs/Mwh of CO_2. The fact that these highly-efficient plants are being constructed by many different operators even in the absence of the NSPS firmly demonstrates that they are economic. Far from imposing "exorbitant" costs on industry, efficient plants save fuel costs per unit of electricity produced, and so lower costs.

Under these circumstances, there is no credible argument that the proposed standard, or even a significantly more rigorous standard for gas-fired plants, would impose significant costs upon industry. As these economic analyses demonstrate, EPA's conclusion that the standard is economically achievable is justified both for individual plants and for the industry nationally. Courts have made it clear that EPA may examine the economic achievability of a standard at the "*broadest sense at the national and regional levels and over time* as opposed to simply at the plant level in the immediate present." In *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981) (emphasis added). Viewed over the next eight years, the industry plainly will continue its shift away from expensive coal-fired electricity, further supporting EPA's conclusion that the NSPS is manifestly achievable and cost-effective.

IV. Monitoring, Compliance, and Enforcement Issues

Compliance with the GHG performance standard is, of course, essential to ensure the benefits of that standard. EPA proposes a monitoring and compliance scheme that allows facilities to report their emissions on the basis of either fuel consumed or direct monitoring of actual emissions, that incorporates a monthly reporting period, and that

[160] Attached as **Ex. 40.**

provides an affirmative defense for exceedances attributable to malfunctions. Proposed 60 C.F.R. §§ 60.5530, 60.5535, 60.5540. In general, the proposal provides a workable system when applied to intermediate- and baseload gas-fired power plants, although EPA should clarify the calculation of penalties for noncompliance and we object to the proposed affirmative defense. For coal-fired power plants, EPA should require direct monitoring of emissions, removing the option for emission estimates based on fuel inputs.

A. EPA Should Clarify Penalties and the Duration of Violations

EPA proposes to average emissions over a 12 month period for purposes of determining compliance with the standard. Proposed 40 C.F.R. § 60.5520(a). We acknowledge the appropriateness of a long averaging time to account for daily and seasonal fluctuations in electricity demand, together with source's differing efficiencies at various loads. This long averaging period raises issues regarding penalties and enforcement. EPA should answer these questions now, rather than awaiting individual enforcement actions, and ensure that penalties are sufficient to incentivize compliance.

EPA proposes to require facilities to "measure or calculate a 12 month rolling average CO2 emission rate, calculated per calendar month, in terms of tons/MWh." 77 Fed. Reg. at 22437-38 (Proposed 40 CFR §§ 60.5525(c), 60.5540(a)-(b)). Each month, the facility must calculate average emissions per output for the month, then calculate the average of monthly averages for the prior year. Proposed 40 C.F.R. § 60.5540. The facility "is determined to have excess emissions" if this "12-operating month rolling average value" exceeds the applicable emissions limit. *Id.*

A facility that violates this limit will be subject to penalties, but EPA has not addressed how those penalties will be calculated. The Clean Air Act provides for imposition of penalties of up to $37,500 "per day of violation" of NSPS standards. CAA § 113(d)(1)(B), 42 U.S.C. § 7413(d)(1)(B); 40 C.F.R. Part 19 (adjusting $25,000 maximum daily penalty for inflation). EPA should explicitly state that when a facility's twelve-month average CO2 emissions exceed the applicable limit, the facility has been in violation of the limit for every day of the preceding year[161]. The "violations" the CAA is concerned with are excess emissions themselves, not merely the days on which calculation occur. Further, irrespective of whether the emissions on a given day are above or below the standard, each day's emissions contribute to the violation of the annual average.

Relatedly, EPA should require daily, rather than monthly, calculation of the rolling annual average emissions. Under this approach, once a facility calculates an initial violation, each subsequent day on which the rolling average exceeds the limit is another

[161] Under EPA's standard practice with respect to rolling averages, days that have already contributed to the initial violation are not counted again if the violation continues on subsequent days.