UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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Standards of Performance for	)	**Docket No. EPA-HQ-OAR-2013-0495**
Greenhouse Gas Emissions from	)	
New Stationary Sources: Electric	)	*Via email*
Utility Generating Units	)	*May 9, 2014*
	)	

Thank you for accepting these comments on EPA's proposed Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units ("EGU NSPS," or "GHG NSPS"), 79 Fed. Reg. 1430 (Jan. 8, 2014).

We submit these comments on behalf of Sierra Club, Clean Air Task Force, Environmental Defense Fund, Natural Resources Defense Council, Earthjustice, Environmental Law and Policy Center, Southern Environmental Law Center, and the National Wildlife Federation (together, "Joint Environmental Commenters").[1]

I. Introduction

As EPA has properly concluded, the scientific record demonstrating that "elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future U.S. generations is robust, voluminous, and compelling."[2] Electric generating units ("EGUs") are the single largest source of domestic greenhouse gas ("GHG") emissions. Accordingly, as we discuss at length below, EPA must control greenhouse gas pollution from this source category under section 111 of the Clean Air Act ("CAA" or the "Act"), 42 U.S.C. § 7411. Significantly reducing these emissions from new and existing domestic power plants is necessary to mitigate the serious harms associated with climate change in the United States.

In this introductory section, we briefly describe some of the harms associated with greenhouse gas emissions and show why the emissions profile of the EGU sector demands expeditious regulation under section 111.

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[1] Clean Air Task Force joins in these comments with the exception of Section VI.

[2] 75 Fed. Reg. 49,556, 49,557 (Aug. 13, 2010) (Endangerment Reconsideration Denial), attached as **Ex. 1;** *see also* 74 Fed. Reg. 66,496, 66,523 (Dec. 15, 2009) (Endangerment Finding), attached as **Ex. 2***; Coalition for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 122—28 (D.C. Cir. 2012) (upholding Endangerment Finding in its entirety).

A. Climate Change and Ocean Acidification Caused by EGU Emissions Threaten Public Health and Welfare.

EPA's Regulatory Impact Analysis ("RIA")[3] provides an overview of the pressing threats posed by greenhouse gas emissions and ably canvasses the dangers that the New Source Performance Review ("NSPS") must combat. The RIA is based largely on EPA's 2009 Endangerment Finding as well as on major assessments by the U.S. Global Change Research Program ("USGCRP"), the Intergovernmental Panel on Climate Change ("IPCC"), and the National Research Council ("NRC").[4] The climate science that forms the basis of the Endangerment Finding provides a legally sufficient and scientifically compelling justification for curbing greenhouse gas emissions from power plants. Global greenhouse gas emissions and atmospheric concentrations—and hence the risk of catastrophic damage—have increased since EPA issued the Endangerment Finding, a fact that highlights the importance of emissions controls.[5] Climate research and assessment reports published since 2009 (including several issued since EPA issued its initial NSPS proposal for GHGs in April 2012) further emphasize the urgency of tackling climate change and the need to mitigate greenhouse gas emissions.[6]

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[3] EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units* ("RIA"), EPA-452/R-13-003 (Sept. 2013), *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf.

[4] *See* RIA at 3-1, 3-8. Many of the fundamental assessment reports upon which the Endangerment Finding and the RIA rely are attached and incorporated by reference. The IPCC's *Climate Change 2007: Synthesis Report* (2007) is attached as **Ex. 3**; the NRC's national report entitled *Advancing the Science of Climate Change* (2010) is attached as **Ex. 4**; and the USGCRP's *Global Climate Change Impacts in the United States (Second National Climate Assessment Report)* (2009) is attached as **Ex. 5**.

[5] The more temperatures rise, the greater the risk that non-linear climate thresholds could be reached, generating abrupt changes with potentially catastrophic impacts for natural systems and human societies. NRC, *Abrupt Climate Change, Inevitable Surprises,* (2002), at v, 16, 154; U.S. Climate Change Science Program, *Abrupt Climate Change* (2008), at 10. Such thresholds include melting of the Greenland Ice Sheet, dramatic changes in weather systems, and Amazon and boreal forest dieback. *See USGCRP, Third National Climate Assessment: Final Report* (May 2014), at 812 fig.24, *available at* http://nca2014.globalchange.gov/system/files_force/downloads/low/NCA3_Climate_Change_Impacts_in_the_United_States_LowRes.pdf.

[6] *See, e.g.* NRC, *supra* n. 2; NRC, *Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (2011), attached as **Ex. 6**; IPCC, *Working Group I Contribution to the IPCC Fifth Assessment Report—Climate Change 2013: The Physical Science Basis—Final Draft Underlying Scientific-Technical Assessment* (2013), attached as **Ex. 7**; USGCRP, *Third National Climate Assessment Report* [Draft Report] (2013), *available at* http://ncadac.globalchange.gov/download/NCAJan11-2013-publicreviewdraft-fulldraft.pdf (the web address for the final report for the Third National Climate Assessment is provided in n.5, *supra*); *see also* RIA at 3-8—3-9 (listing publications).

1. Harms Associated with Climate Change

Climate change will comprehensively alter our world. As the RIA recognizes, these changes will cause a wide variety of harms.

a. Direct Threats to Public Health and Welfare from Climate Change

Climate change is threatening, and will continue to threaten, public health in many regards. It is expected to increase the incidence and severity of heat waves, for instance, which are particularly dangerous to the elderly, the very young, and the infirm.[7] Warmer days lead to enhanced ozone (or smog) formation, which can exacerbate respiratory illnesses, contribute to asthma attacks and hospitalizations, and heighten the risk of premature death among affected populations.[8] Because a warmer atmosphere retains more moisture, climate change will produce heavier precipitation events, stronger tropical cyclones, and associated flooding, spreading toxins and diseases and causing severe infrastructure damage, social upheaval, and widespread injury and death.[9] Pathogens and pests are expected to disseminate among susceptible populations due to changes in those species' survival, persistence, habitat range, and transmission under changing climate conditions, further endangering the public.[10]

As EPA has attested at length, climate change also threatens public welfare. Sea level rise is well documented and is very likely to accelerate over the coming decades.[11] Rising seas, amplified by storm surges and stronger tropical cyclones, will threaten our coastal homes, cities, and infrastructure, forcing expensive efforts to protect or relocate critical resources.[12] Millions of U.S. citizens will be affected and many will be displaced. Further inland, early spring melts will increase flood risks early in the melt season and shrinking snowpack will cause water shortages throughout much of the West, which now depends on snowpack as a reliable water source.[13] Droughts, especially in the western and southern United States, are expected to occur more frequently, and the extent of drought-affected ecosystems is projected to grow by 11 percent for every degree Celsius of warming.[14] This phenomenon will exacerbate the water scarcity already affecting numerous regions of the country.[15] Furthermore, the combination of changing atmospheric chemistry and shifting, and more violent weather patterns, will likely cause crop damage and crop failure, with corresponding increases in food prices and declines in

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[7] RIA at 3-1—3-2.

[8] *Id.* at 3-2—3-3, 5-39—5-40. *See also* Pfister *et al.*, *Projections of Future Summertime Ozone Over the U.S.*, Journal of Geophysical Research: Atmospheres (May 5, 2014) (higher temperatures increase smog formation in already polluted areas), attached as **Ex. A1**.

[9] *Id.* at 3-3.

[10] *Id.*

[11] *Id.* at 3-6.

[12] *Id.* at 3-3, 3-6—3-7.

[13] *Id.* at 3-5.

[14] *Id.* at 3-5, 3-8; USGCRP, *supra* n. 4 at 33, 44.

[15] RIA at 3-5.

availability.[16] On forested lands, the same changes will instigate more severe fires, pest outbreaks, and higher tree mortality, which will likely disrupt timber production.[17]

b. Climate-Linked Threats to Ecosystems Upon Which Society Depends

Natural environments and biodiversity provide humans with a wide range of benefits or "ecosystem services," including fresh water supplies, fertile soil for agriculture, fisheries, climate regulation, and aesthetic, cultural, and recreational benefits.[18] However, climate change will have major implications for wildlife, biodiversity, and the fundamental ecosystem services upon which we depend. Observed changes in our climate are already shifting habitat ranges, altering migration patterns, and affecting reproductive timing and behavior.[19] At anticipated levels of increased global temperature, many terrestrial, freshwater, and marine species are at far greater risk of extinction than in the past.[20] The situation is particularly dire for Arctic wildlife, as climate change causes significant loss of sea ice and a dramatic reduction in marine habitat for polar bears, ice-inhabiting seals, and other animals.[21] And the resilience of many ecosystems is likely to be exceeded this century by an unprecedented combination of climate change, associated disturbances (e.g., flooding, drought, wildfire, insects, and ocean acidification), and other global change drivers (e.g., land use change, pollution, fragmentation of natural systems, and overexploitation of resources).[22]

The footprint of humans on the planet is now straining ecosystems more than at any time in history. Terrestrial, freshwater, and marine environments have already undergone extensive transformation and deterioration.[23] More than 75 percent of Earth's ice-free land has been altered by human activity.[24] Nine of the world's fourteen biomes (each of which designates a broad ecological land category) have been converted into cropland at factors ranging from 20 to 50 percent.[25] Over 40 percent of the world's oceans, including two-thirds of

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[16] *Id.* at 3-4.
[17] *Id.* at 3-4—3-5.
[18] USGCRP, *supra* n. 4 at 291.
[19] *Id.* at 3-7.
[20] *Id.*
[21] *Id.*
[22] *See* IPCC, *supra* n. 4 at 48.
[23] *See generally id.* at 291-313; Millennium Ecosystem Assessment, *Ecosystems and Human Well-being: Biodiversity Synthesis* (2005), Chapters 4 and 28, attached as **Ex. 8**; Brook *et al., Synergies among extinction drivers under global change,* 23 Trends in Ecology and Evolution 453 (2008), attached as **Ex. 9**; Butchart *et al.*, *Global Biodiversity: Indicators of Recent Declines*, 328 Science 1164 (2010), attached as **Ex. 10**.
[24] Ellis and Ramankutty, *Putting people in the map: anthropogenic biomes of the world*, 6 Frontiers in Ecology and the Environment 439, 439 (2008), attached as **Ex. 11**.
[25] Millennium Ecosystem Assessment, *supra* n. 23 at 79.

the ocean waters within the United States' Exclusive Economic Zone, are designated as having an anthropogenic impact rating of at least "medium high."[26]

Together with these many other stressors, climate change is having a major effect on ecosystems. For example, research indicates that climate change and other anthropogenic factors are causing the sixth mass extinction of global biodiversity in the last 600 million years of life on Earth, with current extinction rates 100 to 1,000 times greater than historical rates.[27] In 2007, the IPCC concluded that by the mid-21st century, 15 to 37 percent of plant and animal species worldwide would be committed to extinction if temperatures increase 1.6 to 1.8 degrees Celsius above late 20th century levels.[28] "Specialist" species—those with a narrow tolerance for changes in habitat, diet, or other environmental conditions—are particularly vulnerable to the threat of extinction due to climate change.[29]

Even species that do not go extinct will have to contend with ecological conditions they have not previously faced. Many terrestrial species are shifting their geographical ranges in response to a changing climate. Plants and animals have moved to higher elevations at a median rate of 0.011 kilometers per decade and to higher latitudes at a median rate of 16.9 kilometers per decade, two to three times faster than previously reported.[30] For example, of the 305 bird species tracked in annual Christmas bird counts during the last four decades, 177 species (58 percent) had significant northward range shifts, with more than 60 species moving 100 miles or farther.[31] These range shifts are likely to cause unprecedented interactions among species.

Shifts in seasons, especially in the duration and intensity of winter, are also having significant impacts on ecosystems. One consequence of shifting seasons is the increased likelihood of mismatches between interdependent species (e.g., predator and prey, insects and

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[26] Halpern *et al.*, *A Global Map of Human Impact on Marine Ecosystems,* 319 Science 948, 949 (2008), attached as **Ex. 12**; Kappel *et al.*, *In the Zone: Comprehensive Ocean Protection*, 25 Issues in Science and Technology 33, 38 (2009), attached as **Ex. 13**.

[27] Pimm *et al.*, *The Future of Biodiversity*, 269 Science 347, 347 (1995), attached as **Ex. 14**; Dirzo and Raven, *Global State of Biodiversity and Loss*, 28 Annual Review of Environment and Resources 137, 137 (2003), attached as **Ex. 15**; Barnosky *et al.*, *Has the Earth's sixth mass extinction already arrived?*, 471 Nature 51 (2011), attached as **Ex. 16**; Pereira *et al.*, *Scenarios for Global Biodiversity in the 21st Century*, 330 Science 1496, 1497 (2010), attached as **Ex. 17**; *see also* Pimm, *Biodiversity: Climate Change or Habitat Loss—Which Will Kill More Species?*, 18 Current Biology R117 (2008), attached as **Ex. 18** (discussing impact of climate change on species' survival rates).

[28] IPCC, *Climate Change 2007: Impacts, Adaptation, and Vulnerability* (2007) at 243, *available at* http://www.ipcc.ch/pdf/assessment-report/ar4/wg2/ar4-wg2-chapter4.pdf.

[29] *See generally* Clavel *et al.*, *Worldwide decline of specialist species: toward a global functional homogenization?,* 9 Frontiers in Ecology and the Environment 222 (2011), attached as **Ex. 19**.

[30] Chen *et al*., *Rapid Range Shifts of Species Associated with High Levels of Climate Warming*, 333 Science 1024 (2011), attached as **Ex. 20**.

[31] National Audubon Society, *Birds and Climate Change: Ecological Disruption in Motion* at 3 (2009), attached as **Ex. 21**.

flowers).[32] A striking example is found in western forests, where warmer winters and longer growing seasons have triggered more intense and extensive forest fires, promoting mountain pine beetle outbreaks that kill millions of trees across millions of hectares of forest.[33] In turn, the decreased availability of whitebark pine nuts as a food source for grizzly bears has been tied to lower cub birth rates, lower over-winter survival rates, and increased conflicts between bears and humans.[34]

In the coming decades, climate-related disturbances (such as altered precipitation regimes and extremes in weather and temperature) will continue to have marked impacts on ecosystems. In some cases, these phenomena will cause ecosystems to transition to significantly different community types.[35] For example, more arid ecosystems and river habitat areas will likely be particularly sensitive to changes in precipitation and water supply caused by climate change.[36] Reduced river flow and longer droughts in these regions are projected to diminish native cottonwood and willow populations and render them more susceptible to livestock grazing and encroachment from upland species and invasive weeds.[37] Such changes in ecosystem composition and function will pose critical adaptation challenges for affected human communities.

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[32] *See generally, e.g.*, Miller-Rushing *et al.*, *The effects of phenological mismatches on demography*, 365 Philosophical Transactions of the Royal Society B: Biological Sciences 3177 (2010), attached as **Ex. 22**; Thackeray *et al*., *Trophic level asynchrony in rates of phenological change for marine, freshwater and terrestrial environments*, 16 Global Change Biology 3304 (2010), attached as **Ex. 23**; Yang *et al.*, *Phenology, ontogeny and the effects of climate change on the timing of species interactions*, 13 Ecology Letters 1 (2010), attached as **Ex. 24**.

[33] Westerling *et al*., *Continued warming could transform Greater Yellowstone fire regimes by mid-21st century*, 108 Proceedings of the National Academies of Science, U.S.A. 13165 (2011), attached as **Ex. 25**; Westerling *et al.*, *Warming and Earlier Spring Increase Western U.S. Forest Wildfire Activity* 313 Science 940 (2006), attached as **Ex. 26**; U.S. Forest Service, Climate Change Resource Center, *Western U.S. Bark Beetles and Climate Change* (2008), *available at* http://www.fs.fed.us/ccrc/topics/insect-disturbance/bark-beetles.shtml.

[34] Gunther *et al*., *Grizzly bear–human conflicts in the Greater Yellowstone ecosystem, 1992—2000*, 15 Ursus 10 (2004), attached as **Ex. 27**; USGCRP, *Impacts of Climate Change on Biodiversity, Ecosystems, and Ecosystem Services: Technical Input to the 2013 National Climate Assessment* (2012) at 3-13—3-14, *available at* http://downloads.usgcrp.gov/NCA/Activities/Biodiversity-Ecosystems-and-Ecosystem-Services-Technical-Input.pdf.

[35] *See generally* Peters *et al*., *Directional climate change and potential reversal of desertification in arid and semiarid ecosystems*, 18 Global Change Biology 151 (2012), attached as **Ex. 28**; Rood *et al.*, *Declining summer flows of Rocky Mountain rivers: Changing seasonal hydrology and probable impacts on floodplain forests*, 439 Journal of Hydrology 397 (2008), attached as **Ex. 29**.

[36] Rood, *supra* n. 35 at 405.

[37] *Id.* at 409; *see also* Stromberg *et al.*, *Effects of Stream Flow Patterns on Riparian Vegetation of a Semiarid River: Implications for a Changing Climate*, 26 River Research and Applications 712 (2010), attached as **Ex. 30**.

In short, greenhouse gas emissions are fundamentally destabilizing global ecosystems. Because human society depends upon the goods and services these ecosystems provide, this ecological crisis is a pressing threat to public welfare.

c. Harms Associated With Ocean Acidification

Some of the carbon dioxide ("CO_2") emitted via fossil fuel combustion is subsequently absorbed by the world's oceans. Because carbonic acid forms when carbon dioxide dissolves in water, rising CO_2 emissions are causing the seas to become more acidic. Independent of climate change, ocean acidification alone demonstrates that greenhouse gases endanger public welfare. The NRC has reported that ocean acidity has increased approximately 30 percent since pre-industrial times, and could intensify by three to four times this amount by the end of the century if carbon emissions remain uncurbed.[38] Furthermore, increasing rates of ocean acidification may hamper the oceans' ability to absorb more CO_2, resulting in more atmospheric carbon and, in turn, intensified climate change.[39]

Increased acidification poses a significant threat to the ocean's critical food webs. For instance, it will sharply reduce the underwater area suitable for coral reefs, which function as fish nurseries.[40] Similarly, planktonic animals, which are an important food supply for many underwater species, may be unable to tolerate more acidic waters.[41] By disrupting the delicate balance of oceanic ecosystems, acidification could have devastating impacts on coastal communities that rely heavily on the sustained health of their fisheries.

Ocean acidification is taking place with extraordinary rapidity. According to a 2012 study that surveyed hundreds of millions of years of ocean chemistry, the current rate of CO_2 release into the oceans (and hence the rate of acidification) "stands out as capable of driving a combination and magnitude of ocean geochemical changes potentially unparalleled in at least the last ~300 [million years] of Earth history."[42] Based on future projections of atmospheric carbon concentration, ocean acidity can be expected to increase by 100 to 150 percent by the end of this century.[43] Troublingly, this upward shift in acidity will be accompanied by increasing surface stratification of the ocean on account of warmer surface waters. As a result, phytoplankton will experience both heightened acidity and more intense exposure to light. Together, these two phenomena have been shown to dramatically reduce the photosynthesis and growth of diatoms, currently responsible for approximately 40 percent of total primary

[38] NRC, *supra* n. 4 at 55.
[39] *Id.*
[40] *Id.* at 55-56, 59-60; NRC, *supra* n. 5 at 209-210.
[41] NRC, *supra* n. 4 at 55-56, 59-60; NRC, *supra* n. 5 at 209-210.
[42] Hönsich *et al.*, *The Geological Record of Ocean Acidification*, 335 Science 1058, 1058 (2012), attached as **Ex. 31**.
[43] Gao *et al.*, *Rising CO_2 and Increased Light Exposure Synergistically Reduce Marine Primary Productivity*, 2 Nature Climate Change 519, 519 (2012), attached as **Ex. 32**.

production in the oceans.[44] Accordingly, the combination of heightened acidification and ocean stratification may result in a "widespread decline in marine primary production," doing great damage to the base of the oceanic food chain with potentially devastating effects on the food supply for many regions around the globe.[45]

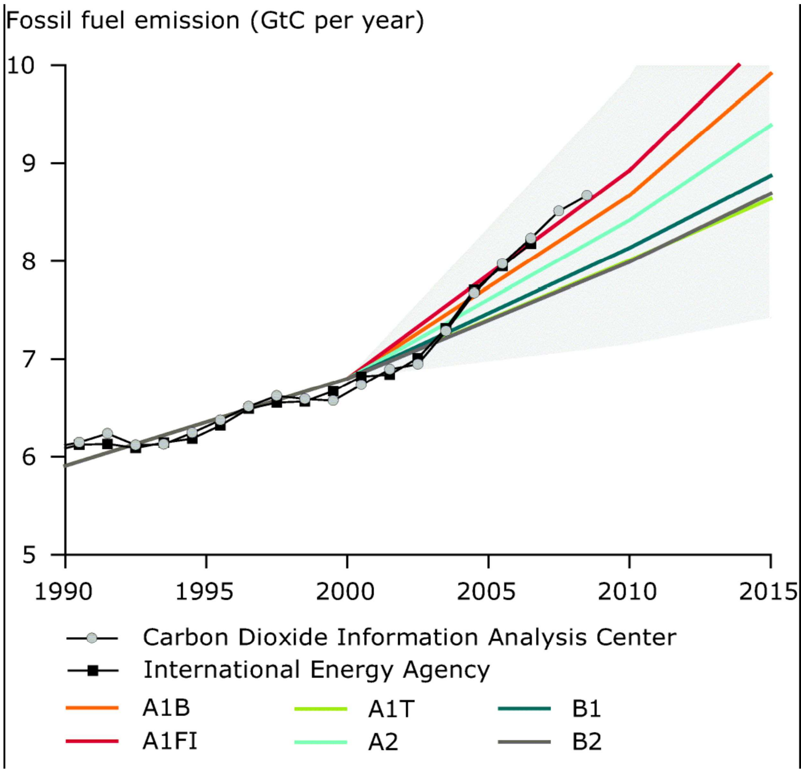
2. New Research, Reports, and Assessments Show Increasing Severity of Harm

Greenhouse gas emissions and atmospheric carbon concentrations have continued to rise in the years since EPA made its Endangerment Finding. As EPA moves forward with the NSPS, the evidence of an intensifying threat reflects the importance of selecting the most protective standards possible in this rule, as well as the need for continued efforts to control emissions from other sectors.

Global greenhouse gas emissions are now rising faster than the IPCC's highest emissions scenario from 2007, as illustrated in the figure below, compiled by the European Environment Agency.[46]

[44] *Id.* at 519-522.
[45] *Id.* at 519.
[46] "Observed global fossil fuel CO_2 emissions compared with six scenarios from IPCC," *available at* http://www.eea.europa.eu/data-and-maps/figures/observed-global-fossil-fuel-co2/ccs102_fig2-3.eps.

Fig. 1: IPCC Emission Scenarios
Source: European Environment Agency



The graph shows six IPCC emissions scenarios (labeled A1B to B2), compared with actual atmospheric carbon measurements from two sources. The highest scenario, A1F1, which assumes a "world of very rapid economic growth" with "fossil-intensive" energy systems,[47] is the most aggressive scenario generally modeled. The graph demonstrates that, in the last decade, global emissions have rapidly increased to match, or even slightly outpace, the A1F1 scenario. Hence, in the absence of swift emissions reductions, we can expect harms even greater than those projected under the IPCC's highest emissions scenarios in the Fourth Assessment Report (AR4).

Recent modeling results project that, by mid-century, warming may be significantly greater than scientists had previously forecast. According to this research, by 2050, average global temperatures could warm by 1.4 to 3 degrees Celsius relative to the 1961-1990 period, even under mid-range emissions scenarios (which current emissions figures significantly exceed).[48] Numerous large-scale reports and assessments (including several published since EPA's initial NSPS proposed rule in April 2012) further attest that threats to public health and welfare from carbon emissions are even more pressing than anticipated just a few years ago. For instance, it is now clear that the IPCC's sea level rise projections in AR4 were overly

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[47] *See* IPCC, *supra* n. 4 at 44.

[48] *See* abstract for Rowlands *et al.*, *Broad range of 2050 warming from an observationally constrained large climate model ensemble*, 5 Nature Geoscience 256 (2012), attached as **Ex. 33**.

conservative. A recent IPCC report notes that "satellite-measured sea levels continue to rise at a rate closer to that of the upper range of [earlier] projections" and that "the contribution to sea level due to [ice] mass loss from Greenland and Antarctica is accelerating."[49] Similarly, in the 2013 draft of its contribution to the ongoing Fifth Assessment Report (AR5), the IPCC's Working Group 1 predicts that sea levels could increase by as much as .81 meters by the late 21st century and .97 meters by 2100.[50] By contrast, the AR4's upper bound estimate for sea level rise was just .59 meters by the late 21st century.[51]

More broadly, Working Group 1 emphasizes that "[s]ubstantial advancements in the availability, acquisition, quality, and analysis of observational data sets in atmosphere, land surface, ocean, and cryosphere have occurred since the AR4."[52] These advancements point primarily toward increased estimates of the severity of the harm that will result from climate change. The draft report for AR5, for instance, asserts that "[m]easurements of glacier change have increased substantially in number since AR4," and that, with regard to the Greenland Ice Sheet, "large rates of mass loss have spread to wider regions than reported in AR4."[53] The draft report also increases AR4's estimates of the radiative forcing (or heat-trapping) potential of current and predicted atmospheric greenhouse gas concentrations,[54] and expresses increased confidence since AR4 in its determinations regarding upper-ocean warming,[55] the link between climate change and precipitation patterns,[56] the human influence on global surface temperature increases,[57] water cycle variations,[58] daily temperature maxima,[59] extreme precipitation events,[60] and droughts,[61] to name just a few examples.

The USGCRP's 2013 draft report for its Third Climate Assessment reflects a similar pattern. Describing changes from the Second Climate Assessment, the authors explain that "[c]ontinued warming and an increased understanding of the U.S. temperature record, as well as multiple other sources of evidence, have strengthened our confidence in the conclusions that the warming trend is clear and primarily the result of human activities."[62] For example, the authors emphasize that "[h]eavy precipitation and extreme heat events are increasing in a manner consistent with model projections, the risks of such extreme events will rise in the

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[49] IPCC, *Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (2012), at 178-79, attached as **Ex. 34**.
[50] IPCC, *supra* n. 5 at TS-63.
[51] IPCC, *supra* n. 4 at 47.
[52] IPCC, *supra* n. 5 at TS-5.
[53] *Id.* at TS-9.
[54] *Id.* at TS-19—TS-24.
[55] *Id.* at TS-32.
[56] *Id.* at TS-35.
[57] *Id.* at TS-40.
[58] *Id.* at TS-37.
[59] *Id.* at TS-38.
[60] *Id.*
[61] *Id.*
[62] USGCRP, *supra* n. 5 at 27.

future, and "[a] longer and better-quality history of sea level rise has increased confidence that recent trends are unusual and human-induced. Limited knowledge of ice sheet dynamics leads to a broad range of potential increases over this century."[63]

Finally, in May 2013, the Interagency Working Group on the Social Cost of Carbon ("IWG"), which includes representatives from a host of federal agencies (including EPA), published an updated assessment of the social cost of carbon that increases the predicted threat that climate change poses and will continue to pose into the future. The IWG's original estimate in 2010 provided four potential values to represent the cost that each metric ton of CO_2 emissions will impose on society for the year 2020: $7, $26, $42, and $81.[64] The 2013 estimate increases those values to $12, $43, $65, and $129, respectively.[65] While the Joint Environmental Commenters believe that these updated figures fundamentally underestimate the true cost of carbon emissions, they nonetheless reflect the same trend as seen in the scientific literature: not only does the potential harm from carbon emissions increase with each additional ton released into the atmosphere, but the severity of the predicted harm increases as our understanding of climate change grows.

These new studies, reports, and assessments indicate that the urgency of acting to curb greenhouse gas emissions has, if anything, grown since both the 2009 Endangerment Finding and the initial NSPS proposed rule from April 2012. Emission trajectories are already at or beyond what was anticipated in the 2007 IPCC reports, and are causing severe effects on an accelerated timeline. In the absence of substantial emissions reductions, the harms to public health and welfare from climate change may well prove catastrophic.

B. Climate Stabilization Requires Immediate, Deep Reductions in Emissions from the EGU Sector

1. Emissions from the U.S. Power Sector Must be Controlled to Prevent Serious Harm to Public Health and Welfare

CO_2 emissions from power plants remain the single largest source of U.S. greenhouse gas pollution and are a significant component of global emissions. Without emissions controls for this sector, it will be impossible to stabilize atmospheric greenhouse gas emissions at a safe level.

EPA's Inventory of Greenhouse Gas Emissions and Sinks reports that electricity generation was responsible for 2,022 million metric tons of CO_2 in 2012 (the most recent year

[63] *Id.*
[64] IWG, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (2013), at 2, *available at* http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf, attached as **Ex. 35**.
[65] *Id.*

for which data is available), constituting 37.5 percent of annual U.S. CO_2 emissions.[66] Power plant emissions of GHGs are larger than those of the next largest stationary source category, oil and gas production, and are larger than emissions from the entire U.S. transportation sector.[67] If we are to reduce the United States' contribution to global warming, we must address this major emissions source.

Importantly, doing so will require controlling emissions from *all* fossil fuel-fired EGUs, not just coal plants. This is because natural gas plants, in particular, also emit significant amounts of CO_2 and because, as EPA recognizes, the majority of (if not all) new fossil-fired plants in the United States are likely to use natural gas as fuel. *See, e.g.*, 79 Fed. Reg. 1430, 1480 (Jan. 8, 2013). Further efforts to cut carbon emissions must therefore include reductions from these plants.

Specifically, in 2012, combustion at coal-fired power plants was responsible for 1,511.2 million metric tons of CO_2 emissions, while combustion at natural-gas-fired plants was responsible for 492.2 million metric tons.[68] The dominance of coal combustion emissions demonstrates why controls on all coal-fired power plants are necessary to reduce sector-wide emissions, but, as the data reveal, natural gas-fired plant emissions are also highly significant.

This fact is critical because natural gas-fired power plants are the primary source of growth in the category. Records from the Energy Information Administration ("EIA") indicate that from 2007 to 2012, as the boom in shale gas production lowered gas prices, net coal generation fell from over 2 billion MWh to 1.51 billion MWh, and it is set to decline further.[69] During the same period, net natural gas generation climbed from 896 million MWh to over 1.22 billion MWh, as a result of both increased capacity factors at existing plants and new facility construction.[70] EPA has predicted that these trends will likely continue and intensify. 79 Fed. Reg. at 1480.

Although CO_2 emissions from new natural gas plants are lower than those from conventional coal-fired plants, those plants emit substantial amounts of CO_2, and the standards should therefore require use of the most efficient and lowest-emitting natural gas plants with state-of-the-art combined cycle turbines. In a separate rulemaking, EPA should also require measures to ensure that potent methane emissions from the production, processing, transportation, and distribution of natural gas are minimized.[71] Otherwise, we will be unable to

[66] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990—2012* (2014), at Table 2-1, attached as **Ex. 36**.
[67] *Id.*
[68] *Id.* at Table 3-5.
[69] EIA, *Electric Power Monthly* (Dec. 2013), at Table 1.1, attached as **Ex. 37**.
[70] *Id.*
[71] We note that greenhouse gas emissions from the natural gas production required to support these power plants are also significant; gas and oil production are the second largest stationary sources of greenhouse gas pollution according to EPA. *See* EPA, *supra* n. 66 at Table 2-1. EPA's recent emissions standards for that sector contain partial collateral mitigation of methane emissions from production,

curb dangerous climate-destabilizing emissions and responsibly manage the nation's natural gas resources. Furthermore, it is essential that the nation's clean air and clean energy policies stimulate innovation in and deployment of low-carbon and renewable energy resources and energy efficiency. These technologies are critical if we are to transition to an electricity sector that minimizes our impact on global climate change.

2. Deep Cuts in U.S. Power Sector Emissions Are Consistent with the Need for Global Emissions Reductions

Domestic action to combat climate change will have benefits that extend far beyond our borders. As of 2010, the United States was responsible for approximately 13.4 percent of global anthropogenic greenhouse gas emissions.[72] U.S. power sector emissions constitute approximately 4.5 percent of worldwide emissions of all anthropogenic greenhouse gas emissions and over 6 percent of all CO_2 emissions.[73] Reducing carbon pollution from domestic power plants will help to substantially curb our contribution to climate change.

Reductions from large sources like the U.S. power sector are important because steep global cuts are necessary to prevent truly disastrous climate impacts. In its final draft contribution to AR5 regarding climate change mitigation strategies, IPCC's Working Group 3 states that "the stabilization of GHG concentrations requires fundamental changes in the global energy system relative to a baseline scenario,"[74] and that "[t]he electricity sector plays a major role in mitigation scenarios with deep cuts of GHG emissions."[75] The NRC's 2011 report on climate stabilization emphasizes that steep emissions reductions, on the order of 80 percent globally, are necessary to stop atmospheric CO_2 concentrations from reaching dangerous levels and temperatures from exceeding 2 degrees Celsius above pre-industrial levels.[76] As shown by

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and so are critically important to maintain and strengthen as production expands. These standards, however, reveal significant gaps; most notably, they do not directly control methane and do not set standards for existing infrastructure, which produces the bulk of emissions. If natural gas generation continues to play an important role in the EGU sector, EPA must set appropriate production standards directly regulating methane to ensure that increases in natural gas generation are not coupled with increases in greenhouse gas pollution due to methane leakage during gas extraction, processing, transmission, and distribution.

[72] European Union Emission Database for Global Atmospheric Research (EDGAR), *GHG (CO_2, CH4, N2O, F-gases) emission time series 1990-2010 per region/country*, *available at* http://edgar.jrc.ec.europa.eu/overview.php, and *CO2 time series 1990-2012 per region/country*, *available at* http://edgar.jrc.ec.europa.eu/overview.php?v=CO2ts1990-2012.

[73] According to the EDGAR database, global GHG emissions in 2010 were 50,101 million metric tons CO_2e.

[74] IPCC, *Working Group III- Mitigation of Climate Change, Chapter 7: Energy Systems* (2014), at 58, attached as **Ex. 38**.

[75] *Id.* at 64.

[76] NRC, *supra* n. 5 at 10.

the following table reproduced from AR5, to avoid a temperature increase on such a scale, global CO_2 emissions must fall by between 50 and 85 percent by 2050.[77]

Table 1: Correlation Between Atmospheric CO_2 Concentrations and Global Mean Temperatures
Source: IPCC, Fifth Assessment Report

Category	Radiative forcing (W/m^2)	CO_2 concentration[c)] (ppm)	CO_2-eq concentration[c)] (ppm)	Global mean temperature increase above pre-industrial at equilibrium, using "best estimate" climate sensitivity[b), c)] (°C)	Peaking year for CO_2 emissions[d)]	Change in global CO_2 emissions in 2050 (% of 2000 emissions)[d)]	No. of assessed scenarios
I	2.5-3.0	350-400	445-490	2.0-2.4	2000-2015	-85 to -50	6
II	3.0-3.5	400-440	490-535	2.4-2.8	2000-2020	-60 to -30	18
III	3.5-4.0	440-485	535-590	2.8-3.2	2010-2030	-30 to +5	21
IV	4.0-5.0	485-570	590-710	3.2-4.0	2020-2060	+10 to +60	118
V	5.0-6.0	570-660	710-855	4.0-4.9	2050-2080	+25 to +85	9
VI	6.0-7.5	660-790	855-1130	4.9-6.1	2060-2090	+90 to +140	5
						Total	177

a) The understanding of the climate system response to radiative forcing as well as feedbacks is assessed in detail in the AR4 WGI Report. Feedbacks between the carbon cycle and climate change affect the required mitigation for a particular stabilization level of atmospheric carbon dioxide concentration. These feedbacks are expected to increase the fraction of anthropogenic emissions that remains in the atmosphere as the climate system warms. Therefore, the emission reductions to meet a particular stabilization level reported in the mitigation studies assessed here might be underestimated.
b) The best estimate of climate sensitivity is 3°C [WG 1 SPM].
c) Note that global mean temperature at equilibrium is different from expected global mean temperature at the time of stabilization of GHG concentrations due to the inertia of the climate system. For the majority of scenarios assessed, stabilisation of GHG concentrations occurs between 2100 and 2150.
d) Ranges correspond to the 15th to 85th percentile of the post-TAR scenario distribution. CO_2 emissions are shown so multi-gas scenarios can be compared with CO_2-only scenarios.

The IPCC has determined with "high confidence" that "[d]elaying mitigation efforts beyond those in place today through 2030 is estimated to substantially increase the difficulty of the transition to low longer-term emissions levels and narrow the range of options consistent with maintaining temperature change below 2°C relative to pre-industrial levels." It will be difficult—perhaps impossible—to meet the reductions needed to stave off the most extreme effects of climate change without swift and significant emissions controls for the U.S. power sector.

In the remainder of these comments, we explain what EPA must do in order to meet its Clean Air Act mandate to ensure that all sources in this sector comply with Section 111 standards. A strong NSPS for fossil fuel-fired power plants is critical to achieving the emissions reductions necessary to mitigate the dangers of climate change.

II. The Changing Nature of the Utility Sector

It is difficult to overstate the transformation in energy markets that has occurred in the United States since EPA listed the first power plant NSPS categories in the 1970s. For many decades, coal-fired generation provided the majority of baseload electricity generation in the

[77] IPCC, *supra* n. 5 at 15.

United States,[78] while natural gas plants generally operated in intermediate-load and peaking modes.[79] In 1978, motivated by a perceived scarcity of fossil fuel resources,[80] 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.[81] In 1987, however, the prohibition was repealed.[82] Between 1988 and 2002, natural gas consumption for electric generation more than doubled, and between 2000 and 2010, more than 80 percent of new electric capacity built in the United States was natural gas-fired.[83]

EIA data indicate that from 2007 to 2013, net coal generation fell from over 2 billion MWh to 1.58 billion MWh.[84] During the same period, net natural gas generation climbed from 896 million MWh to over 1.1 billion MWh, as a result of both increased capacity factors at existing plants and new facility construction. Today, natural gas plants are commonly operating as baseload plants, providing 27 percent of U.S. net power generation in 2013,[85] compared to only 10 percent in 1994.[86] As discussed below, recent market analyses project that the vast majority of EGUs built to serve growth in energy demand in the coming years will be natural gas units, renewable generation, and energy efficiency investments.

A. Recent Trends in the Power Sector

The recent shift across the domestic electricity generating sector away from coal-fired electricity generation is confirmed by the most recent data.[87] Since 2012, the U.S. has seen older and less-efficient existing coal-fired power plants continuing to retire due to increased

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

[79] *See* 44 Fed. Reg. 52,792, 52,796 (Sept. 10, 1979).

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

[81] Powerplant and Industrial Fuel Use Act of 1978, Pub. L. No. 95–620, § 201, 92 Stat. 3289, 3298 (1978) ("New Electric Powerplants").

[82] Repeal of Certain Sections of the Powerplant and Industrial Fuel Use Act of 1978, Pub. L. No. 100-42, § 201, 101 Stat. 310, 311 (May 21, 1987) ("Coal Capability of New Electric Powerplants, Certification of Compliance").

[83] EIA, *Most Electric Generating Capacity Additions in the Last Decade Were Natural Gas-Fired* (July 5, 2011), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=2070. (The cited calculations were made from data available at this page.)

[84] EIA, Electric Power Monthly (Apr. 2014), at Table 1.1, *available at* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01.

[85] *Id.*

[86] EIA, Electric Power Monthly (July 1996), *available at* http://205.254.135.7/electricity/monthly/archive/pdf/02269607.pdf.

[87] EIA, AEO2014 Early Release Overview (Dec. 16, 2014), at 2, Fig. 3, *available at* http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf (hereinafter "AEO2014 Early Release").

competition with other generating resources and impending environmental regulations. Between 2008 and 2013, U.S. utilities retired approximately 20 GW of coal-fired capacity,[88] with approximately 11.3 GW retired in 2012 alone.[89] As of December 2013, utilities had announced firm plans to retire some 47 GW of coal-fired generating capacity (or to convert it to natural gas) by 2021.[90] And according to a recent market study, a further 17 GW is "at risk" of retirement due to competition with low-cost natural gas.[91] As coal-fired capacity has declined, so has generation from the coal-fired fleet: in 2013, coal-fired EGUs accounted for 39.1 percent of U.S. generating output—slightly higher than the low of 37.4 percent reached in 2012, but still representing a 20 percent decline in market share since 2006.[92]

The decline in U.S. reliance on its coal generation has coincided with rapid domestic expansion of zero- and lower-carbon generating unit development and electricity generation. For example, April 2013 saw a record amount of electricity generated from U.S. wind resources of over 17,000 GWh—nearly as much wind-generated electricity produced in one month as U.S. wind resources delivered in all of 2005.[93] From 2011 to 2013, electricity delivered to the grid from wind generators increased by at least 28 percent (from a total of 120,177 GWh in 2011, to a total of 167,665 GWh in 2013).[94] Similarly dramatic has been the expansion of solar energy, which increased in generation capacity by 418 percent between 2010 and 2014.[95] Energy efficiency also grew rapidly during this period: utility and private spending on energy efficiency investments increased to over $12 billion in 2012,[96] and in 2011, first-year energy savings reported by utilities totaled 22 million MWh—an increase of approximately 22 percent year-over-year.[97] And consistent with the trends described above, the North American Electric

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[88] NERC, *2013 Long-Term Reliability Assessment* (Dec. 2013), at 35, *available at* http://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/2013_LTRA_FINAL.pdf, attached as **Ex. 39**.

[89] EIA, Electric Power Annual, Table 4.6 (Dec. 2013), *available at* http://www.eia.gov/electricity/annual/pdf/epa.pdf.

[90] Gilbert and Gelbaugh, *Coal Under Fire: Assessing Risk Factors and Market Impacts for Upcoming Coal Retirement Decisions* (SNL Energy, Dec. 2013), at 16, attached as **Ex. 40**.

[91] *Id.*

[92] EIA, Short-Term Energy Outlook (Jan. 2014), at 21, *available at* http://www.eia.gov/forecasts/steo/archives/Jan14.pdf.

[93] EIA, Electric Power Monthly (Feb. 2014), Table 1.1.A, *available at* http://www.eia.gov/electricity/monthly/current_year/february2014.pdf.

[94] *Id.*

[95] EIA, Electricity Monthly Update (Apr. 2014), *available at* http://www.eia.gov/electricity/monthly/update/archive/april2014/.

[96] Business Council on Sustainable Energy, *2014 Sustainable Energy in America Factbook* (Feb. 2014), at 4, *available at* http://www.bcse.org/factbook/pdfs/2014 Sustainable Energy in America Factbook.pdf, attached as **Ex. 41**.

[97] American Council for an Energy–Efficient Economy, *2013 State Energy Efficiency Scorecard* (Nov. 2013), at 30, *available at* http://www.aceee.org/research-report/e13k, attached as **Ex. 42**.

Reliability Corporation ("NERC") reports that about 40 GW of net natural gas-fired capacity was added in North America from 2008 to 2013.[98]

Looking ahead, forecasts indicate that with the possible exception of a small number of projects already under development, new coal-fired generating capacity will neither be needed nor economically viable over at least the next decade.[99] For example, EIA predicts in its *Annual Energy Outlook 2014 Early Release Overview* that total domestic coal-fired capacity will decrease by over 15 percent from 2012 to 2040.[100] EIA attributes this trend to slower growth in electricity demand, competition from renewable energy and natural gas,[101] and economic changes resulting from more stringent environmental regulations.[102] Similarly, NERC anticipates that 31.5 GW of net coal-fired capacity will retire by 2023.[103]

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[98] NERC, *supra* n. 88 at 35. As explained in the preamble to the proposed NSPS, gas-fired electricity generation has significantly lower combustion emissions than does coal-fired generation. *See* 79 Fed. Reg. at 1434-35. Although methane is beyond the scope of EPA's current proposal, we note that there are currently significant methane emissions from gas production and distribution, which diminish this advantage. *See, e.g.*, Brandt *et al*, *Methane Leaks from North American Natural Gas Systems*, Science, Vol. 343, no. 6172, DOI: 10.1126/science.1247045 (Feb. 14, 2014) at 733-735, attached as **Ex. 43**; Alvarez *et al.*, *Greater focus needed on methane leakage from natural gas infrastructure*, Proceedings of the National Academy of Science, DOI: 10.1073/pnas.1202407109 (Apr. 2012), attached as **Ex. 44**.

[99] *See* Joint Institute for Strategic Energy Analysis, *Natural Gas and the Transformation of the US Energy Sector* (Nov. 2012) (modeling showed that no new coal-fired generating capacity was economically viable until nearly 2030 at the earliest, due to the availability of affordable CCGT and onshore wind generation).

[100] AEO2014 Early Release, *supra* n.87 at 14.

[101] EIA defines "renewable energy" as "energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action." EIA, Glossary, *available at* http://www.eia.gov/tools/glossary/. Notably, while many of these generating choices are zero carbon-emitting, unfortunately all biomass-fueled energy cannot be assumed to be "carbon neutral" or zero-emitting, or even low carbon-emitting in some instances. For example, burning chipped whole trees to generate electricity has the same or higher tons CO_2/MWh output as burning coal. *See, e.g.*, Manomet Center for Conservation Sciences, *Massachusetts Biomass Sustainability and Carbon Policy Study, Report to the Commonwealth of Massachusetts Department of Energy Resources* (Walker, ed.) (National Capital Initiative Report No. NCI-2010-03) (2010), *available at* http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/biomass/biomass-sustainability-and-carbon-policy-study.html (demonstrating using modeling that the combination of greater carbon emissions per unit energy from biomass than fossil fuels, combined with the lost forest carbon sequestration associated with additional fuel harvesting, produce net CO_2 emissions that greatly exceeded those from fossil fuels—a "carbon debt" that takes decades to more than a century to pay off), attached as **Ex. 45**.

[102] AEO2014 Early Release, *supra* n.87 at 14. The Reference case includes implementation of MATS and CAIR, as well as market concerns about GHG emissions, which dampen the expansion of coal-fired capacity. *Id.*

[103] NERC, *supra* n. 88 at 10.

EPA notes in the preamble to the proposed rule that as coal-fired plants retire, current power sector economics suggest that they will likely be replaced with new natural gas combined cycle plants ("NGCCs," also known as combined cycle gas turbines, or "CCGTs")[104] and with zero-emitting wind, solar, and energy efficiency resources.[105] Most of these new lower emitting electricity sources currently have much lower construction and operating costs than coal-fired EGUs,[106] and this trend is also likely to continue in the coming years.[107] As EPA notes in the preamble, these lower costs translate into a wide gap between the cost of electricity produced from a conventional pulverized coal EGU and the cost of CCGT or renewables. Electricity from a new supercritical pulverized coal EGU costs approximately $92/MWh, or 56 percent higher than the cost of CCGT (at a moderate gas price of $6.11/Mcf) and as much as 31 percent higher than the cost of onshore wind. 79 Fed. Reg. at 1477. As a result of these cost disparities, EIA's latest *Annual Energy Outlook* forecasts only 2.5 GW of additional planned coal-fired generating capacity through 2040, with nearly 90 percent of this capacity consisting of projects that are already under way.[108] Similarly, the International Energy Agency ("IEA") *World Energy Outlook 2013* predicts that capacity replacements for retired units in the U.S. will come largely from facilities that utilize natural gas (about 33 percent), wind (28 percent), and solar (15 percent).[109] NERC similarly anticipates that natural-gas-fired units will replace coal-fired units over the next few years, with 28.6 GW of net natural gas-fired capacity additions by 2023, and some plants coming online between 2014 and 2017 to compensate for coal-fired retirements.

U.S. reliance on natural gas for electricity generation is expected to surpass reliance on coal generation by 2035, according to the EIA.[110] The newest estimates of future natural gas-fired generation development have been revised upward from the 2013 *Annual Energy Outlook*.[111] EIA also expects generation from renewables to be higher than was estimated in

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[104] NGCC and CCGT are interchangeable terms, although we rely primarily on the latter throughout these comments.
[105] *See* 79 Fed. Reg. at 1443 ("The EPA has reviewed publicly available IRPs from a range of companies . . . and these plans are generally consistent with both EIA and EPA modeling projections. Companies seem focused on demand-side management programs to lower future electricity demand and mostly reliant on a mix of new natural gas-fired generation and renewable energy to meet increased load demand and to replace retired generation capacity.").
[106] EIA, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (Apr. 2013), at 6, *available at* http://www.eia.gov/forecasts/capitalcost/ (reporting that even the lowest-cost coal-fired EGU configuration has capital costs that are nearly three times higher than an advanced CCGT and 33 percent higher than onshore wind on a per-kW basis).
[107] AEO2014 Early Release, *supra* n. 87 at 14.
[108] EIA, *Annual Energy Outlook 2014* (May 2014), at Table A9, *available at* http://www.eia.gov/forecasts/AEO/; *see also* 79 Fed. Reg at 1478.
[109] IEA, *World Energy Outlook 2013* (Nov. 2013), at 181 available at http://www.worldenergyoutlook.org/publications/weo-2013/.
[110] AEO2014 Early Release, *supra* n.87 at 14.
[111] *Id.*

2013 across most of the projection period,[112] with renewable sources accounting for almost a third of the growth in generation resources from 2012 to 2040 as they become more cost-competitive with other fuels.[113] Indeed, EIA projects that renewables will be the fastest-growing source of electric generation through 2040.[114] Consistent with these estimates, IEA predicts that natural gas-fired generation in the U.S. will grow 38 percent from 2011 to 2035.[115] And NERC expects that U.S. on-peak generation provided by natural gas will increase to 41 percent by 2023.[116]

B. The Impact of Natural Gas Prices

While EIA and IEA project that modest increases in the price of natural gas may occur in the coming years as a result of increasing demand for this fuel.[117] Coal-fired power generation will continue to face stiff competition from existing natural gas plants for the provision of baseload power, and will also continue to be uncompetitive as a *new* source of generation. This situation is predicted to continue so long as natural gas prices remain below $10/MMBtu.[118] According to the 2014 EIA forecast, delivered natural gas prices in the power sector are expected to remain at historically low levels (less than $6/MMBtu) through the late 2020s – far below the $10/MMBtu price point that would cause *new* conventional coal-fired generation to be cost-competitive with CCGT.[119] Furthermore, NERC sees continued lower natural gas prices through 2023 as providing an incentive for fuel-switching from coal to natural gas.[120] And coal is becoming more expensive to mine despite improvements in technology.[121] These trends will only exacerbate the competitive challenges facing new coal-fired EGUs.

Market projections and utility sector analyses also suggest that the baseload shift from coal to natural gas generation in the existing EGU fleet will continue, regardless of whether there are small to moderate natural gas price changes. And a recent study of the cost impacts of the Mercury and Air Toxics Standards ("MATS"), the Clean Air Interstate Rule ("CAIR"), [122]

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[112] *Id.* at 15.
[113] *Id.* at 14.
[114] *Id.* at Table A8 (showing average annual growth of 1.7 percent for renewable generation through 2040).
[115] IEA, *supra* n. 109 at 183.
[116] NERC, *supra* n. 88 at 36.
[117] AEO2014 Early Release, *supra* n.87 at 7; IEA, *supra* n. 109 at 184-84.
[118] RIA at 5-24.
[119] *Id.* at Table A3.
[120] NERC, *supra* n. 88 at 11.
[121] *Id.* at 7.
[122] In the coming months EPA will implement the Cross-State Air Pollution Rule ("CSAPR") following the Supreme Court's decision in *EPA v. EME Homer City Generation, L.P.*, Nos. 12-1182, 12-1183, 572 U.S. __ (Apr. 29, 2014). CSAPR establishes more-restrictive requirements than those in CAIR. *See* Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208, 48,321 (Aug. 8, 2011) (explaining that individual states will not be allowed to exceed their budgets through trading under CSAPR, unlike CAIR); *see also* EPA, Regulatory

and other regulations found that the implementation of these rules will make the operating costs of natural gas plants cost-competitive with most coal plants—at least up to a natural gas price-to-coal price ratio of 4.3, and even before the implementation of EPA's forthcoming standards for CO_2 emissions from existing fossil-fired EGUs.[123] That ratio stood at just 1.8 in 2013, and EIA projects that it will remain at 2.4 or less through 2035.[124] Thus, the collective impact of market forces and current and future CAA regulations designed to protect public health are expected to reinforce the competitiveness of CCGT vis-à-vis coal as a source of baseload power.

In sum, the shift in the electricity generating sector from coal to lower-emitting resources has continued apace since EPA originally proposed CO_2 performance standards for this industry in April 2012. Forecasts of fuel costs, capital costs, and other power sector trends continue to indicate—as they have consistently since the original proposal—that new conventional coal-fired generation will be neither needed nor economically viable over the foreseeable future, regardless of the proposed NSPS. Finally, the existing coal-fired generating fleet is expected to continue to face significant competitive pressure from gas-fired EGUs which are currently a competitive source of baseload power and will likely remain so over the coming decades, as well as from increasingly cost-competitive renewable resources and energy efficiency opportunities.

III. Statutory Background

The Clean Air Act's explicit purpose is "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." 42 U.S.C. § 7401(b)(1). To this end, the CAA requires EPA to set performance standards for listed categories of stationary sources. 42 U.S.C. § 7411.

Section 111 directs EPA to publish a list of categories of stationary sources and include a category in the list if, in EPA's judgment, the category causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. *Id.* § 7411(b)(1)(A). When deciding whether to list a source category, EPA must necessarily consider the health and welfare impacts of the air pollution that sources in the category emit, in

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Impact Analysis (RIA) for the final Transport Rule, Docket ID No. EPA-HQ-OAR-2009-0491, at 255-56 (June 2011) ("Fossil-fuel-fired electric generating units in the Transport Region are projected to achieve NO_x and SO_2 emissions reductions through a combination of compliance options. These actions include sustained operation of existing controls originally built for CAIR, additional pollution control installations at coal-fired generators, coal switching (including blending of coals), and increased dispatch of more efficient units and lower-emitting generation technologies (e.g., some reduction of coal-fired generation with an increase of generation from natural gas). In addition, there will be some affected sources that find it more economic to retire rather than invest in new pollution control equipment.").

[123] Pratson *et al.*, *Fuel Prices, Emission Standards, and Generation Costs for Coal vs Natural Gas Power Plants*, 47 Env. Sci. & Tech. 4926 (Mar. 2013).

[124] AEO2014 Early Release, *supra* n.87 at Table A3 (ratio reflects EIA projections of delivered prices of coal and natural gas used in power generation).

conjunction with the significance of the category's overall contribution to air pollution. After listing a source category, EPA must then promulgate federal standards of performance for such sources.[125] *Id.* § 7411(b)(1)(B). The statute further requires EPA to "review, and, if appropriate, revise such standards" every eight years. *Id.* Electric utility steam generating units and stationary gas turbines were listed as section 111 source categories in 1971 and 1977, respectively.[126]

EPA now proposes CO_2 performance standards for new sources under the electric utility steam-generating units and stationary gas turbine categories. In *Massachusetts v. EPA*, the Supreme Court held that the CAA authorizes federal regulation of emissions of CO_2 and other greenhouse gases, and directed EPA to make a science-based determination as to whether greenhouse gases from motor vehicles endanger public health and welfare. 549 U.S. 497, 528-29 (2007). In December 2009, EPA concluded that emissions of greenhouse gases, including CO_2, "cause or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare." 74 Fed. Reg. 66,496 (Dec. 15, 2009). And in 2011, the Supreme Court agreed that the CAA authorizes CO_2 standards for power plants under section 111, and that that authority preempts common-law actions in tort for damages due to emissions of climate pollution. *Am. Elec. Power Co. v. Connecticut ("AEP")*, 131 S.Ct. 2527, 2537-39 (2011).

The CAA requires standards of performance to reflect "the degree of emission limitation achievable through the application of the best system of emission reduction ["BSER"] 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." 42 U.S.C. § 7411(a)(1). Because the statute does not set forth weights EPA must assign to cost, energy, and environmental impact factors when determining BSER and setting new source performance standards, the agency has discretion in balancing these factors.[127] *Lignite Energy Council v. U.S. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (citing *New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992)).

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[125] Alternatively, the Administrator may promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction that she determines has been adequately demonstrated, if it is not feasible to prescribe or enforce a standard of performance. 42 U.S.C. § 7411(h)(1).

[126] *See* 36 Fed. Reg. 5,931 (Mar. 31, 1971) (listing fossil-fuel fired electric steam generating units and boilers); 42 Fed. Reg. 53,657 (Oct. 3, 1977) (listing fossil-fuel fired combustion turbines); 44 Fed. Reg. 33,580 (June 11, 1979) [codified as subpart Da at 40 C.F.R. §§ 60.40Da—60.52Da] (setting performance standards for electric utility steam generating units); 44 Fed. Reg. 52,792 (Sept. 10, 1979) [originally codified at 40 C.F.R. Part 60, Subpart GG, currently codified as subpart KKKK at 40 C.F.R. §§ 60.4300—60.4420] (setting performance standards for stationary combustion turbines).

[127] The agency's discretion under section 111 is bounded by the reviewing court's consideration of whether the decision was based on the relevant factors and whether there has been a clear error of judgment. *See Essex Chem. Corp.*, 486 F.2d at 433-34.

A. Legislative History of New Source Performance Standards

The legislative history of section 111(b) indicates that Congress intended for NSPS to reflect the most highly-effective emission reduction systems that are technically and economically feasible, including new and innovative pollution control technologies that are not in routine use. When Congress first enacted the CAA in 1970, the Senate and House of Representatives passed amendments to section 111, both of which are reflected in the language of the statute. The Senate's version of the bill "would have required that [section 111(b)'s performance] standards reflect 'the greatest degree of emissions control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.'" *See Portland Cement Ass'n v. Ruckelshaus (Portland Cement I)*, 486 F.2d 375, 391 (D.C. Cir. 1973), *cert. denied*, 417 U.S. 921 (1974) (discussing legislative history and quoting S. Rep. No. 9-1196, at 16 (1970)). The Senate further clarified that "this does not mean that the technology must be in actual, routine use somewhere," but simply that it be available to be installed in new plants during the eight-year period after the standards are finalized. *Id.* (citing S. Rep. No. 9-1196, at 16). For its part, the House presented a bill that "would have [required] 'the Secretary [to] give appropriate consideration to technological and economic feasibility.'" *Id.* (quoting H. Rep. No. 91-1146, at 10 (1970)). The House Report suggested, "'in order to be considered "available" the technology may not be one which constitutes a purely theoretical or experimental means of preventing or controlling air pollution.'" *Id.* & n.60 (quoting H. Rep. No. 91-1146, at 10).

The final language signed into law that year adopted neither chamber's recommendation directly, but incorporated aspects of both. The statute as enacted defined "standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated." 42 U.S.C. § 1857c-6(a)(4) (1970) (recodified at 42 U.S.C. § 7411(a)(1) (1990)). With this language, Congress attempted to insure that EPA would limit new source pollution "to the greatest degree practicable if the national goal of a cleaner environment was to be achieved." *Essex Chem. Corp.*, 486 F.2d at 443 n.14. In interpreting the 1970 language of the CAA, the *Portland Cement I* court found that the term "adequately demonstrated" required a showing by EPA "that there *will be* 'available technology'" during the regulated future." *Portland Cement I*, 486 F.2d at 391 (emphasis added).

In 1977, Congress amended select CAA provisions because they were not operating as intended. In particular, Congress was concerned that the statute was encouraging a "race to the bottom": individual states were relaxing pollution control standards to lure industry from states with more stringent requirements, thus gaining a competitive advantage over their more environmentally-conscious neighbors. *See* H.R. Rep. No. 95-294, at 184 (1977). To counteract this trend and "create incentives for improved technology," Congress amended section 111 so as to mandate the adoption of the "best technological system of continuous emissions reduction." 42 U.S.C. § 7411(a) (1977); Clean Air Act Conference Report: Statement of Intent;

Clarification of Select Provisions, 123 Cong. Rec. 27071 (1977). *See also* H.R. Rep. No. 95-294, at 189 ("[I]t 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."); *Sierra Club v. Costle*, 657 F.2d 298, 346 n.174 (D.C. Cir. 1981) ("[S]ection 111 was intended 'to assure the use of available technology and to stimulate the development of new technology.'" (quoting S. Rep. No. 95-127, at 114 (1977)); *Pacific Power Co. v. EPA*, 647 F.2d 60, 68 (9th Cir. 1981) (holding that Congress intended that new source emissions controlled under section 111 would be reduced "to a minimum").

The 1977 amendments defined best technology "in terms of 'long-term growth,' [and] 'long-term cost savings.'" *Sierra Club*, 657 F.2d at 331 (quoting Clean Air Act Conference Report, 123 Cong. Rec. at 27,021). Requiring new stationary sources to adopt pollution control technology at the time of construction, when plant owners and operators can most efficient install the equipment, rather than waiting for environmental degradation to occur and only then requiring expensive retrofits, achieves long term savings. *See* H.R. Rep. No. 95-294 at 185*; see also Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 783. The legislative history also states that the costs of applying pollution control should be "considered by the owner of a large new source of pollution as a normal and proper expense of doing business." H.R. Rep. No. 95-294 at 184. Among other things, the 1977 amendments were "intended to create incentives for improved technology, which could achieve greater or equivalent emission reduction at equivalent or lower cost, energy demand, and environmental impacts." *Id.* at 186.

In 1990, Congress amended section 111 once again, reviving the original (1970) language of section 111(a)(1). The D.C. Circuit has since expressed that "section 111 'looks toward what may fairly be projected for the regulated *future*, rather than the state of the art at present.'" *Lignite Energy Council*, 198 F.3d at 934 (quoting *Portland Cement I*, 486 F.2d at 391) (emphasis added). The recent case law aligns with decisions in all of the cases since section 111 was enacted, holding that EPA must look to the technological vanguard when setting new source standards so as to encourage innovation and yield long-term cost savings.

B. These Standards Must be Forward-Looking and Technology-Forcing

The threat of climate change requires immediate and significant action if we are to avoid further damage from a more serious climate crisis in the coming decades. As EPA has recognized, a crucial step forward is limiting heat-trapping carbon pollution emitted by the largest industrial sources. This approach comports with the priorities that the statute requires EPA to consider when establishing performance standards. *See* 42 U.S.C. § 7411(f)(2) (1977) (priorities include quantity of pollution emitted, extent of the endangerment, and mobility and competitiveness of the source category). EPA is easily within its authority to seek deep cuts in carbon emissions from EGUs based on the best available systems of emissions reduction. In fact, section 111 *requires* the agency to set technology-based emissions limits for sources that cause or contribute to endangerment of public health or welfare, as fossil fuel-fired EGUs clearly do*.* *See* 42 U.S.C. § 7411(b)(1)(A), (B); s*ee also AEP*, 131 S.Ct. at 2533, 2536 (noting EPA's endangerment finding for greenhouse gases, including CO_2, and stating that defendant power plants represent "the largest emitters of carbon dioxide in the United States").

The legislative history of section 111 and the relevant case law affirm the technology-forcing nature of the statute. For instance, the 1977 Senate Report discusses the need "to assure the use of available technology and to stimulate the development of new technology." S. Rep. No. 95-127 at 171. To that end, "[t]he statutory factors which EPA must weigh [when setting performance standards] are broadly defined and include within their ambit subfactors such as technological innovation." *Sierra Club*, 657 F.2d at 346. The agency may thus promulgate standards that reflect "improved design and operational advances" that industry has yet to realize, "so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard." *Id.* at 364; *see also Portland Cement Ass'n v. EPA (Portland Cement III)*, 665 F.3d 177, 190 (D.C. Cir. 2011) (EPA properly based the NSPS for new cement kilns on a recent and more efficient model, even though many older kilns still existed that did not utilize the same technology). Moreover, EPA can "extrapolat[e] . . . a technology's performance in other industries", and look beyond domestic facilities to those used abroad. *Lignite Energy Council,* F.3d 930 at 934 n.3.

Section 111 does not mandate any particular percentage reduction of pollution from sources in a regulated industrial category. *See Sierra Club,* 657 F.2d at 298. Rather, the NSPS must reflect the degree of emission limitation achievable through application of the best system of emission reduction, which the Administrator determines has been adequately demonstrated. *Id*.; *see also Portland Cement I*, 486 F.2d at 391. "Adequately demonstrated" does not mean that all existing sources are able to meet the requirement, *see Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 785-86, nor does it require the available technology to be in active use at the time of the rulemaking. *See Portland Cement I*, 486 F.2d at 391. Rather,

> [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 the technology will have to be available.
> . . .
> If actual tests are not relied on, but instead a prediction is made, 'its validity . . . rests on the reliability of [the] prediction and the nature of [the] assumption.

Portland Cement I, 486 F.2d at 391-92 (citing and quoting *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)).

In short, EPA can and must encourage new and more efficient technologies through the standards it sets under section 111. These standards should reflect the use of the "best" control options, including those achieving the deepest reductions, consistent with Congress's intent to encourage technological advancement in controls.

C. EPA May Consider Cost-Effectiveness as Part of the Standard-Setting Process

The statute and case law authorize EPA not only to evaluate the costs of achieving the standard, but also the cost-effectiveness of emissions control options comprising the "best" system of emission reduction.

1. Courts Will Not Invalidate EPA's Choice of BSER Based on Costs Unless They Are Exorbitant

Section 111(a)(1) directs EPA to "take into account" the cost of achieving reductions and any nonair quality health and environmental impacts and energy requirements when determining BSER and setting an NSPS. 42 U.S.C. § 7411(a)(1). Over several decades, the D.C. Circuit has fleshed out the meaning of this directive, rejecting interpretations that would require the agency to conduct a traditional cost-benefit analysis. *See*, *e.g.*, *Essex Chem. Corp.*, 486 F.2d at 437 (cost-benefit analysis was not required for acid mist standards); *Lignite Energy Council*, 198 F.3d at 930 (EPA did not exceed its discretion in setting boiler standards that modestly increased the overall cost of producing electricity). In *Essex*, the court held that EPA's standards must be "reasonably reliable, reasonably efficient, and . . . reasonably . . . expected to serve the interests of pollution control *without becoming exorbitantly costly in an economic or environmental way*." 486 F.2d at 433 (emphasis added). Similarly, in *Portland Cement Association v. Train* (*Portland Cement II)*, 513 F.2d 506, 508 (D.C. Cir. 1975), the court upheld EPA's interpretation that section 111's cost inquiry functions as a safety valve to ensure that the costs an NSPS imposes are not "greater than the industry could bear and survive," but would instead allow industry to "adjust" in a "healthy economic fashion to the end sought by the Act as represented by the standards prescribed." And in *Lignite*, the court held that "EPA's choice [of BSER] will be sustained unless the environmental or economic costs of using the technology are exorbitant." 198 F.3d at 933.

As EPA correctly observes in the preamble to the proposed rule, while past courts have used varying formulations in discussing EPA's authority to take costs "into account," each has followed the same fundamental standard: an NSPS will be upheld unless the costs it imposes are exorbitant or too great for the industry to bear. In fact, the D.C. Circuit has never invalidated an NSPS for being too costly. 79 Fed. Reg. at 1464. For example, in *Portland Cement I*, the court upheld an NSPS for particulate matter emissions, even though control technologies amounted to roughly 12 percent of the capital investment for an entire new plant and consumed five to seven percent of a plant's total operating costs. 486 F.2d 375, 387-88. Likewise, in *Portland Cement III*, the court upheld particulate matter ("PM") standards that were anticipated to increase the cost of cement by one to seven percent, with little projected decrease in demand. 665 F.3d at 191; *see also* 73 Fed. Reg. 34,072, 34,077, 34,086 (June 16, 2008). With respect to the electricity generating industry, the *Lignite Energy Council* court held that a two percent increase in the cost of producing electricity was not exorbitant, and upheld the 1997 nitrogen oxides (“NO_x”) NSPS for EGUs and industrial boilers. *See* 198 F.3d at 933 (citing 62 Fed. Reg. 36, 948, 36,958 (July 9, 1997)).

2. EPA May Reasonably Evaluate the Costs Associated with a Standard by Looking at the Degree of Pollution Control it Achieves

Section 111 makes clear that EPA must consider the degree of emission limitation achieved, as well as the costs of achieving it, when formulating a performance standard. 42 U.S.C. § 7411(a)(1). This does not require the application of a strict cost-benefit test; rather, reviewing courts have upheld performance standards so long as the costs are not exorbitant (i.e., too high for the industry to bear) in light of the pollution reduction benefits they will yield. For example, in *Sierra Club*, the court upheld sulfur dioxide (“SO_2”) standards that would cost industry tens of billions of dollars between 1987 and 1995, but would provide significant benefits, including 100,000–200,000 tons of SO_2 emission reductions per year, cost savings of over $1 billion per year, and a 200,000 barrel-per-day reduction in oil consumption. 657 F.2d at 314, 327-28.

While there exists no dollars-per-ton-removed cost-effectiveness level to serve as a “rule of thumb,” the *Portland Cement III* court upheld PM standards for Portland cement plants that EPA had determined were “well within the range of cost-effectiveness” at about $3,969 per ton of PM emissions removed. 665 F.3d 191; *see also* 73 Fed. Reg. 34,072, 34,076-077 (June 16, 2008) (discussing costs per ton removed by EPA’s BSER for PM, and noting that the agency had previously deemed PM regulations for EGUs to be reasonably cost-effective at $8,400 per ton of PM removed). Similarly, in *Lignite*, the court upheld NO_x performance standards that would cost $1,770 per ton removed, despite the availability of cheaper but less protective alternatives advocated by industry petitioners. 198 F.3d at 933; 62 Fed. Reg. 36,948, 36,953 (July 9, 1997).

As discussed in more detail *infra* in section IV, EPA’s proposed performance standards are cost-effective, particularly in light of the pressing crisis of climate change and the urgent need for deep CO_2 emission reductions.

3. EPA Also May Consider Byproduct Revenue Evaluating the Costs Associated with its Standards

The D.C. Circuit has yet to address directly whether EPA may take byproduct revenue – that is, revenue from the sale of incidental byproducts of pollution control -- into account in determining BSER. However, the court *has* held that the agency has authority to evaluate all of the statutory factors in a BSER determination “in the broadest possible sense,” and to consider costs “at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.” *Sierra Club*, 657 F.2d at 331. Given that, it is appropriate for EPA to consider revenue streams from the co-production of CO_2 in its determination that carbon capture and storage (“CCS”) is BSER for coal-fired EGUs. Furthermore, as EPA asserts, if costs of *disposal* of byproducts must be taken into account during cost analysis, *revenue* from the sale of economically valuable products as a co-benefit of achieving a particular performance standard should also be taken into account. *See* 79 Fed. Reg. at 1,464. To the extent that the sale of captured CO_2 may generate revenues for plant operators, those revenues should be factored into a determination of the proposed rule's costs.

EPA's prior actions are consistent with the notion that byproduct revenue may be considered when the agency sets a performance standard. For example, in 2012, EPA and the National Highway Traffic Safety Administration finalized new fuel economy standards for light-duty vehicles. *See* 77 Fed. Reg. 62,624 (Oct. 15, 2012). In its cost analysis, the agencies determined that the benefits that would result from more stringent standards would "far outweigh higher vehicle costs" to consumers, largely due to the 170 billion gallons of fuel that would be saved throughout the lives of vehicles sold over an eight-year period. *Id.* at 62,629, 62,631. From a macroeconomic standpoint, these savings are functionally indistinguishable from the revenue that would accrue if those 170 billion gallons of fuel were a direct byproduct of the new technology, rather than the amount saved due to reduced demand. That same year, EPA analyzed revenues from the sale of natural gas and condensate recovered through the installation of pollution controls when describing costs associated with the NSPS for oil and natural gas production. *See* 77 Fed. Reg. 49,490, 49,534 (Aug. 16, 2012) (estimating that the proposed standards would save approximately $11 million annually if revenues from additional recovery were considered).

IV. The Costs of Both EPA's Proposed Rule and Joint Environmental Commenters' Proposed Revisions Satisfy the Statutory Requirements.

Section 111(a)(1) of the CAA directs EPA to include costs among the factors it considers when determining BSER. In a line of cases spanning several decades, the D.C. Circuit held that the statute is satisfied as long as the costs of the BSER are not "excessive" or "exorbitant." *See Portland Cement Ass'n*, 486 F.2d at 391; *Essex Chemical Corp.*, 486 F.2d at 433; *Sierra Club*, 657 F.2d at 383; *Lignite Energy Council*, 198 F.3d at 933. Joint Environmental Commenters agree with EPA's conclusion that the proposed NSPS will have no notable impacts on the price of electricity or electricity supplies.[128] EPA considered a wide range of potential market conditions for EGUs and fuels through at least 2030, reflecting analyses by EIA and industry in addition to the agency's own evaluations.[129] This analysis found that electric utilities are likely to choose lower-cost natural gas rather than coal for all, or almost all, new fossil fuel-fired generating units during the relevant time period. Furthermore, new combined cycle gas plants are already likely to satisfy the proposed rule's emission limits, creating no additional costs.[130] In fact, the most efficient combined cycle units are cost-effective and satisfy the lower emission levels proposed by Joint Environmental Commenters. To the extent that new coal plants with partial

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[128] RIA at 5-54.
[129] *Id.* at sections 5.4, 5.5, and 5.9. In these sections, EPA considers EIA's power sector modeling projections, the agency's own power sector modeling projections, electric utility integrated resource planning documents, and projections for new EGUs reported by industry to EIA.
[130] *Id.*; *see also* 79 Fed. Reg. at 1443.

CCS are constructed in the coming years, EPA correctly asserts that they will not impose exorbitant costs on the industry. As such, the proposed standard for new coal-fired plants satisfies section 111's cost component.

The discussion that follows advances three points with regard to the costs of the NSPS. First, Joint Environmental Commenters' recommended more-stringent/tighter standards for natural gas-fired plants would not significantly raise either costs for the new units or the price of electricity. Second, requiring partial CCS for steam EGUs and integrated gasification combined cycle ("IGCC") units would not impose exorbitant costs on the electricity generation industry, and need not cause significant increases in energy prices for consumers. Accordingly, EPA's designation of partial CSS for subpart Da sources satisfies section 111's standards. Lastly, the social cost of CO_2 emissions from new power plants is substantial and should be analyzed along with the co-benefits from reducing related pollutants.

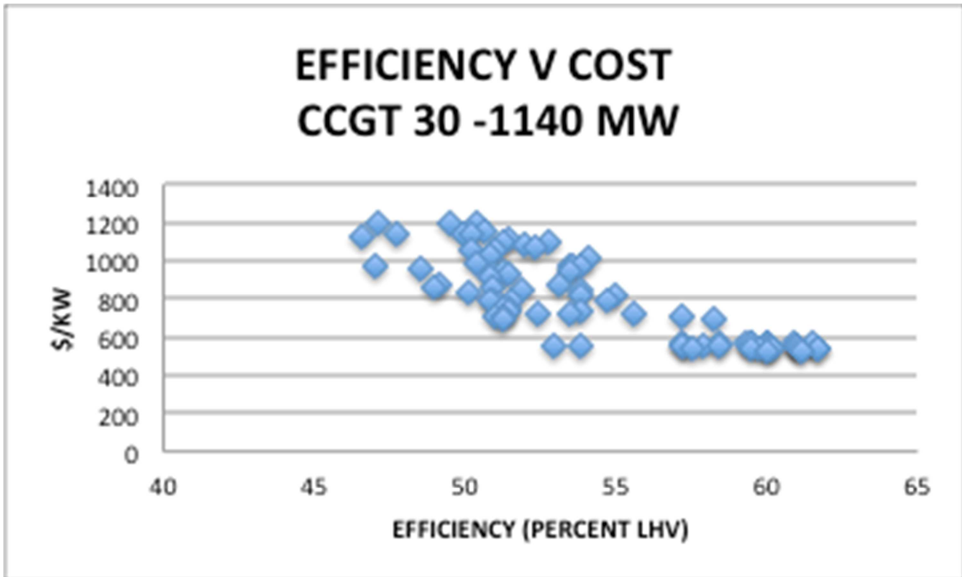
A. Lower Standards for CCGT Plants are Consistent with EPA's Cost Findings

As discussed more fully below (*see* section IX.B, *infra*), Joint Environmental Commenters urge EPA to revise the proposed NSPS for gas-fired plants such that the emission limits, regardless of fuel type, are (on a net output basis) 825 lb CO_2/MWh for baseload units, 875 lb CO_2/MWH for intermediate and load-following units, and 1,100 lb CO_2/MWh for peaking units. Our analysis shows that half or more of currently existing gas plants already meet these standards, including a significantly higher percentage of more recently constructed facilities. Moreover, the data on recent combined cycle plants demonstrate that the lower emission levels are cost effective. Accordingly, the proposed revisions are not only adequately demonstrated, but also promote the most innovative technology, achieve more significant reductions in emissions than would EPA's proposed standards, and do not impose exorbitant or even significant costs, as evidenced by the fact that most new gas-fired EGUs already meet or come close to meeting these standards.

Based on a review of unit costs published in the 2013 Gas Turbine World ("GTW") Handbook,[131] larger units generally exhibit higher efficiency and lower capital costs than smaller units. There is no indication in any of the data that lower efficiency CCGT units cost less than higher efficiency units within the same size class. Since higher efficiency units have lower operating costs, it can be reasonably concluded that requiring the use of higher efficiency CCGTs will not pose significant (let alone exorbitant) costs on the industry. The charts below illustrate this fact.

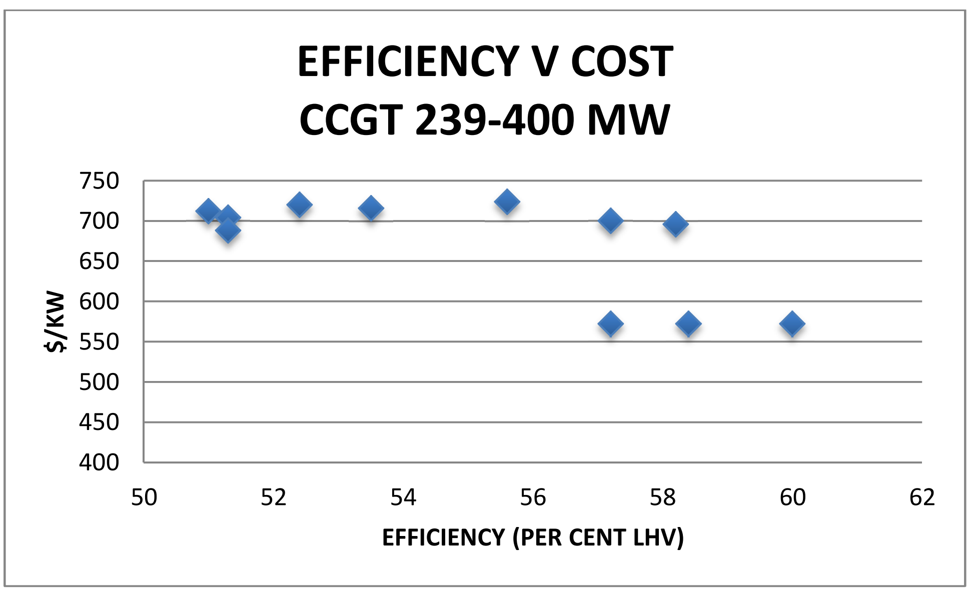
[131] Gas Turbine World, *2013 GTW Handbook*, Vol. 30 (2013), at 50-52.

Fig. 2: Efficiency vs. Cost- CCGTs Generally
Source: 2013 GTW Handbook[132]



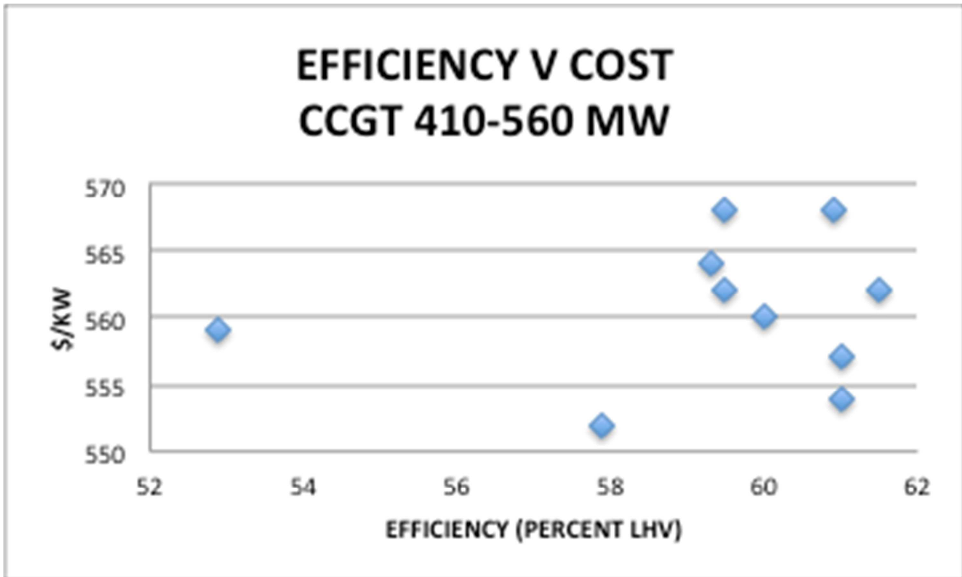
Furthermore, within subcategories of units that might be considered by an operator, more efficient units cost the same as, or less than, less efficient units. Again, the figures below provide ample support for this fact.

Fig. 3: Efficiency vs. Cost- Smaller CCGTs
Source: 2013 GTW Handbook



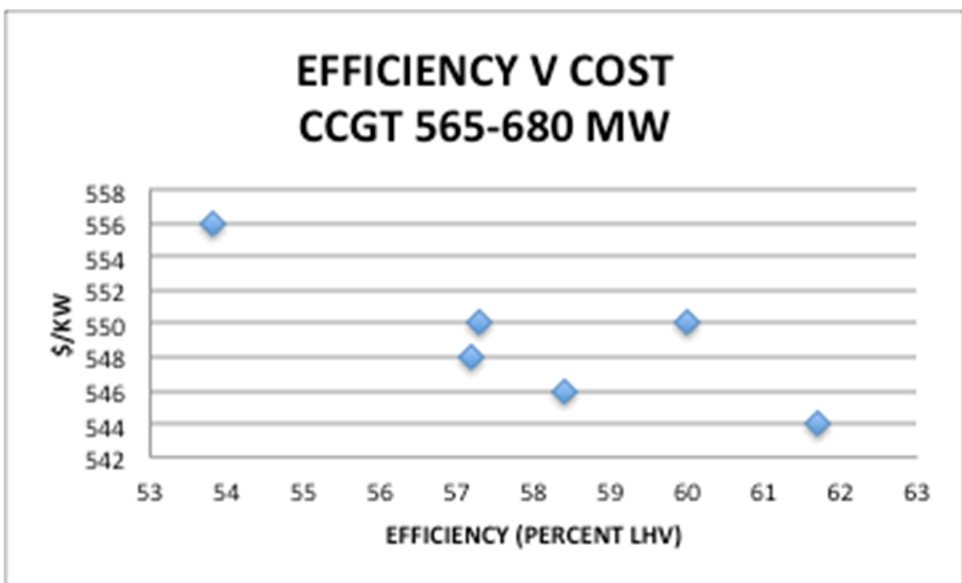
[132] Data for Figures 2 through 5 are also included in **Appendix A- CCGT Cost v Efficiency Analysis**.

Fig. 4: Efficiency vs. Cost- Medium-Size CCGTs
Source: 2013 GTW Handbook



In fact, in the popular 600 MW size category for CCGTs, the data show a distinct trend indicating that more efficient units are less costly to run on a per-kilowatt hour basis than less efficient units.

Fig. 5: Efficiency vs. Cost- Larger CCGTs
Source: 2013 GTW Handbook



For these reasons, Joint Environmental Commenters' recommended performance standards for gas plants are neither excessive nor exorbitant; rather, they fully satisfy section

111's cost component. Promoting new combined cycle gas plants that emit less CO_2 would not notably raise the price of electricity or impair electricity supplies, and would (as the RIA correctly notes) yield substantial benefits by reducing both carbon and other pollutants that harm human health and welfare.[133] On balance, stricter performance standards for gas-fired generating units are amply justified under section 111.

B. EPA Correctly Determined That the Costs of Partial CCS for New Coal Plants Are Reasonable and Far From Exorbitant.

EPA correctly concluded that the costs of installing and operating partial CCS for any new coal plants that may be constructed as a result of the proposed standards are reasonable, and clearly not exorbitant or too high for the industry to bear. As discussed above, EPA has concluded that few, if any, new coal plants would be built in the coming years even in the absence of the proposed NSPS due to the changing economics of the utility sector. Requiring installation and operation of partial CCS at only a few plants would therefore incur costs that the industry as a whole could easily absorb. For this reason, EPA's proposed NSPS would not entail exorbitant costs, and fully satisfy section 111 in this regard. For a fuller discussion of this issue, *see* section VIII.B, *infra*.

C. The Social Cost of CO_2 Emissions from New Power Plants is Substantial and Should Be Analyzed Along with the Benefits from Reduced Quantities of Co-Occurring Pollutants

In addition to considering the costs the NSPS may impose, EPA should address in the final rule the benefits that will accrue as well. It is important to emphasize that section 111 does not require a traditional cost-benefit analysis, but simply requires that an agency's determination of BSER impose costs that are not exorbitant or too high for the industry to bear. *See, e.g.*, *Essex Chem. Corp.*, 486 F.2d at 437; *Lignite Energy Council*, 198 F.3d at 930, *Portland Cement II*, 513 F.2d at 508. Thus, we discuss the benefits that the rule will provide not to indicate that a cost-benefit analysis is necessary, but as further evidence of the fact that the projected costs are not unreasonably high, and to underscore the strong public policy rationale supporting these proposed standards.

In analyzing the proposed rule's benefits, EPA properly relied on the federal government's most recent estimate of the social cost of carbon.[134] Over the course of several years, the IWG has developed a series of values to represent the cost that each metric ton of CO_2 emissions will impose on society.[135] To formulate these values, IWG relied on tested modeling techniques and included a range of scenarios for emissions, population growth, and economic activities.[136] In light of the complexity of these issues, the IWG's estimates are subject to ongoing review, and a number of environmental organizations (including several of

[133] *See* RIA at 5-35—5-42.
[134] *See* RIA at 5-35—5-46.
[135] *See* 78 Fed. Reg. 70,586 (Nov. 26, 2013).
[136] *See* RIA at 5-36 – 5-39; *see also* IWG, *supra* n. 64.

the Joint Environmental Commenters) have proposed various revisions to the IWG's approach that would more robustly reflect the full cost of carbon emissions on society.[137] Nevertheless, the IWG's most recently updated estimates utilized accepted science, economics, and technical modeling, and EPA's reliance on those estimates in support of this rule was reasonable and justified.

Like most pollution problems, the impacts of CO_2 emissions on human health and welfare are difficult to quantify and subject to uncertainties. However, the agency's analysis comported with the standard guidance for regulatory analysis of costs and benefits.[138] Although EPA's estimates in this rulemaking are subject to on-going review and revision, its cost analysis satisfies the statutory standards for a reasonable methodology based on the record. *See, e.g.*, *Sierra Club*, 657 F.2d at 330 ("The language of section 111 . . . gives EPA authority when determining [BSER] to weigh cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.").

Finally, EPA correctly considered the co-benefits of reduced emissions of SO_2 and NO_x that would result from compliance with the proposed rule's CO_2 emission limits.[139] The agency found that

> the emissions of GHGs and other pollutants associated with new sources of electricity generation are greater for coal-fired units than for natural gas combined cycle units (even when accounting for compliance with MATS). Reducing the emissions associated with electricity generation results in both climate and human health and non-health benefits.[140]

Admittedly, the co-benefits from reducing SO_2 and NO_x vary by location, and EPA observed that the locations of any new coal plants are uncertain. Yet the RIA provides monetized estimates of these co-benefits at an illustrative plant, and offers a qualitative assessment of these benefits in the aggregate.[141] EPA's recognition of co-benefits is consistent with the methodology it applied in the MATS rulemaking, which also addressed the rule's positive impacts on emissions of

[137] *See* Sierra Club, *Comments on the Interagency Working Group's (IWG) Technical Support Document: Social Cost of Carbon (SCC) for Regulatory Impact Analysis Under Executive Order 12866* (Docket Not. OMB-2013-0007-0083) (Feb. 25, 2014), **attached as Ex. 46**; EDF, *et al.*, *Comments on the Interagency Working Group's (IWG) Technical Support Document: Social Cost of Carbon (SCC) for Regulatory Impact Analysis Under Executive Order 12866* (Docket No. OMB-2013-0007-0140) (Feb. 26, 2014), **attached as Ex. 47.**

[138] *See* RIA at 5-38; *see also* Office of Management and Budget ("OMB"), *Circular A-4: Regulatory Impact Analysis—A Primer* (Sept. 17, 2003), at Section E, *available at* http://www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf, attached as **Ex. 48**.

[139] RIA at 5-39—5-46.

[140] *Id.* at 5-42.

[141] *Id.* at 5-41.

related pollutants.[142] This methodology is also consistent with scientific studies linking policies to reduce greenhouse gases with shorter-term air quality co-benefits.[143] In short, EPA's estimation of the proposed rule's costs appropriately reflects these co-benefits and, more broadly, represents a reasoned and judicious analysis that fully complies with the dictates of the CAA.

VI. Endangerment Finding

A. EPA Has Appropriately Determined that EGUs in Proposed Subpart 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 of sources, 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." The endangerment and contribution findings are part of the process of listing a category of sources, not the process of promulgating standards of performance for particular air pollutants emitted by those sources. Therefore, 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 the proposed subpart TTTT—namely, that EPA made the required endangerment and contribution determinations when the agency first listed fossil fuel-fired electric steam generating units and fossil fuel-fired combustion turbines, which were later regulated under the new proposed subpart's two components, subparts Da and KKKK. *See* 79 Fed. Reg. at 1454.[144] The proposal correctly states:

> [S]ection 111 does not by its terms require that as a prerequisite for the EPA to promulgate a standard of performance for a particular pollutant, the EPA must first find that the pollutant causes or contributes significantly to air pollution that endangers public health or welfare.

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[142] *Id.* at 5-4, 5-44; *see also* EPA, *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards* ["*MATS RIA*"] (Dec. 2011) at Section 5, *available at* http://www.epa.gov/mats/pdfs/20111221MATSfinalRIA.pdf, attached as **Ex. 49**.

[143] *See, e.g.*, West *et al.*, *Co-benefits of mitigating global greenhouse gas emissions for future air quality and human health*, 3 Nature Climate Change 885 (2013), attached as **Ex. 50**; Nemet *et al.*, *Implications of incorporating air-quality co-benefits into climate change policymaking*, 5 Environmental Research Letters 014007 (2010), attached as **Ex. 51**.

[144] *See also* 44 Fed. Reg. 33,580 (June 11, 1979) (listing subpart Da); 71 Fed. Reg. 38,482 (July 6, 2006) (listing subpart KKKK). If EPA chooses to retain subparts Da and KKKK rather than unify all fossil fuel-fired EGUs into a single Category TTTT, these listings remain in effect, and no additional finding is necessary to justify the current set of proposed regulations.

79 Fed. Reg. at 1453.[145]

Nonetheless, even if section 111 required an endangerment or cause-or-contribute determination for individual pollutants from a given source category, or, alternatively, a rational-basis determination for EPA's regulation of those particular pollutants, the current proposal passes legal muster. Joint Environmental Commenters submit that EPA's December 2009 Endangerment Finding for greenhouse gases (including CO_2) fully satisfies any requirement under section 111, not only for proposed subpart 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 to the sum total of all anthropogenic greenhouse gas "air pollution," irrespective of the sources from which the individual "air pollutants" were emitted. *See, e.g.*, 74 Fed. Reg. 66,496, 66,506 (Dec. 15, 2009) ("[T]he Administrator is to consider *the cumulative impact* of sources of a pollutant in assessing the risks from air pollution, and is not to look only at the risks attributable to a single source or class of sources." (emphasis added)).

This distinction originates in the CAA itself. 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 [her] 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 "air pollution" may reasonably be anticipated to endanger, not the "pollutant" itself. 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. at 66,536 (emphasis in original).

Thus, the Endangerment Finding determined that the "total, cumulative stock" of GHGs—not just mobile source emissions—could reasonably be anticipated to endanger public health and welfare. And as the Endangerment Finding makes clear, the total, cumulative stock of GHGs includes carbon dioxide emissions from fossil fuel-fired electricity generation. *See id.*

[145] The proposal also correctly notes that the statute's silence on this question means that the agency's interpretation is entitled to deference, and will be upheld unless it is unreasonable. *See Chevron, U.S.A., Inc. v. NRDC*, 467 U.S. 837, 844 (1984).

at 66,539-40. Indeed, EGUs are "the largest emitting sector," outpacing emissions from all section 202(a) sources combined. *Id.* at 66,539-40 (section 202(a) sources' emissions are "behind the electricity generating sector"). Therefore, even if the statute *did* require the Administrator to make a finding that a listed industry contributes significantly to the emission of a particular pollutant that endangers public health or welfare, EPA would amply meet that test here. There is no dispute that fossil fuel-fired EGUs contribute significantly to GHG pollution, which the agency has already determined endangers public health and welfare.

The Endangerment Finding was made after an extraordinarily thorough scientific review and careful consideration of public comments. It was reaffirmed after full consideration of petitions for reconsideration and was upheld in its entirety in litigation before the D.C. Circuit. *See Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 116-27 (D.C. Cir. 2012). The court rejected the industry petitioners' arguments and found that the Endangerment Finding was procedurally sound, consistent with Supreme Court case law, and amply supported by the administrative record, observing that "[t]he body of scientific evidence marshaled by EPA in support of the Endangerment Finding is substantial." *Id.* at 120. Further, the Supreme Court recently declined to review this holding when it was squarely presented in petitions for certiorari filed last year. *See Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 418, 2013 U.S. LEXIS 7380 (Oct. 15, 2013).

There is no basis in the statutory text for requiring EPA to replicate this endangerment determination in a section 111 rulemaking. This would be true even if more time had passed since the agency made its determination. Nothing in the statute requires EPA to revisit or reaffirm the 2009 Endangerment Finding for greenhouse gas air pollution when taking subsequent action to limit greenhouse gas emissions from a specific category of mobile or stationary sources under section 202, section 111, or any other provision of the CAA.

Indeed, EPA has on many previous occasions relied upon a previously-existing endangerment finding to regulate a pollutant emitted by a particular source category under section 111. In each instance, EPA examined the category's emissions of air pollutants and the availability of control measures, but in no case did it consider or reconsider whether the pollutant at issue endangered public health or welfare. For example, in 1973, EPA issued performance standards for asphalt concrete plants that limited particulate matter emissions. *See* 38 Fed. Reg. 15,380 (June 11, 1973). The agency had previously determined that particulate matter endangers public health and welfare, and issued the asphalt concrete standards under section 111 without any reviewing that endangerment finding.[146] Likewise, in 2010, as part of its eight-year review of the performance standards for cement kilns under section 111(b)(1)(B), EPA added limitations for cement kilns' NO_x emissions. Here again, the agency did so without reviewing whether NO_x endangers public health or welfare, either directly or as a precursor to ozone or fine particulate matter.[147]

[146] The PM standard was upheld in *Nat'l Asphalt Pavement Assoc. v. Train*, 539 F.2d 775 (D.C. Cir. 1976).
[147] Examples of this practice abound over the course of EPA's history. *See, e.g.*, 74 Fed. Reg. 51,950, 51,957 (Oct. 8, 2009) ("The plain language of section 111(b)(1)(A) provides that such findings are to be

Thus, both the statutory text and EPA's long-established practice confirm that an endangerment determination can support subsequent, unrelated regulations. 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. *See Oljato Chapter of Navajo Tribe v. Train*, 515 F.2d 654, 661 (D.C. Cir. 1975) (describing process under section 307 of the Clean Air Act by which interested parties must submit new information to the agency via a petition for a new rulemaking). Of course, as previously discussed, the scientific and analytical assessments issued since the 2009 Endangerment Finding indicate that, if anything, climate change is a more serious threat than previously realized, and that CO_2 emissions are more, not less, likely to endanger the public health and welfare. *See* section I.A.2, *supra*.

While the 2009 Endangerment Finding was applicable to all anthropogenic greenhouse gas air pollution, the contribution determination formally made in that rulemaking related solely to motor vehicle emissions. The Finding did note, however, that power plants' CO_2 emissions surpass those from the entire transportation sector. *See* 74 Fed. Reg. at 66,539-40. Thus, even if section 111(a)(1)(A) *were* to require an independent determination that the emissions of sources in proposed subpart TTTT "cause or contribute significantly" to greenhouse gas air pollution (and Joint Environmental Commenters believe that it does not), then such a requirement is easily met for this category. As EPA states, "[f]ossil 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." 79 Fed. Reg. at 1441. In fact, EGUs are responsible for approximately 40 percent of total U.S. energy-related CO_2 emissions,[148] and almost one third of total U.S. greenhouse gas emissions.[149] Furthermore, U.S. EGUs are responsible for approximately 6.5 percent of all global anthropogenic CO_2 emissions.[150] As EPA attests in the proposed rule's preamble,

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made for source categories, not for specific pollutants emitted by the source category. . . . Determinations regarding the specific pollutants to be regulated are made, not in the initial endangerment finding, but at the time the performance standards are promulgated.") (amending subpart Y, which had set PM standards since 1976); 41 Fed. Reg. 3826 (Jan. 26, 1975) (relying on an endangerment finding for one pollutant when setting standards for two pollutants); 77 Fed. Reg. 9304 (Feb. 16, 2012) (amending 71 Fed. Reg. 9866 (Feb. 27, 2006) regarding hazardous air pollutant ("HAPs") emissions from fossil fuel-fired EGUs); 75 Fed. Reg. 54,970 (Sept. 9, 2010) (amending 36 Fed. Reg. 24,876 (Dec. 23, 1971) regarding HAPs emissions from Portland cement plants); 73 Fed. Reg. 35,838 (June 24, 2008) (amending 39 Fed. Reg. 9308 (Mar. 8, 1974) regarding petroleum refineries); 70 Fed. Reg. 28,606 (May 18, 2005) (amending 36 Fed.Reg. 24,876 (Dec. 23, 1971) regarding steam-generating EGUs); 54 Fed. Reg. 34,008 (Aug. 17, 1989) (amending 39 Fed. Reg. 9308 (Mar. 8, 1974) regarding fluid catalytic cracking unit regenerators); 52 Fed. Reg. 47,826 (Dec. 16, 1987) (amending 51 Fed. Reg. 42,768 (Nov. 25, 1986) regarding commercial-industrial steam generators).

[148] EPA, *supra* n. 66 at Table 2-4.

[149] *Id.* at Table 2-1.

[150] EDGAR, *supra* n. 72, *CO_2 time series 1990-2012 per region/country*.

> [T]he 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, along with the fact that the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year, provide a rational basis for regulating CO_2 emissions from affected EGUs.

Id. at 1455.

Joint Environmental Commenters agree that "it is not necessary for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution. Under any reasonable threshold or definition, the emissions from EGUs are a significant contribution [to GHG pollution]." *Id.* at 1456. Indeed, as the agency points out, "if fossil fuel-fired EGUs cannot be found to contribute significantly to GHG air pollution, then there is no source category in the U.S. that does contribute significantly to GHG air pollution, a result that would defeat the purposes of CAA section 111." *Id.* n. 110. These are plainly reasonable conclusions, and the only conclusions with respect to carbon pollution that comport with the statute's overarching goal of protecting public health and welfare.

Joint Environmental Commenters therefore strongly agree with EPA that the establishment of carbon pollution standards under section 111 is authorized under either of what the agency calls its first and second alternative interpretations.[151] Under either of these interpretations, the 2009 Endangerment Finding, together with the 2010 disposition of the reconsideration petitions and the D.C. Circuit's ruling in *Coalition for Responsible Regulation*, readily satisfy any statutory requirement for a determination that CO_2 emissions from EGUs may reasonably be anticipated to endanger public health or welfare. Although not legally necessary, EPA could supplement that determination in this rulemaking with reference to the recent reports (included as exhibits to these comments) by the NRC, the USGCRP, the IPCC, the IWG, and others. Likewise, under either alternative interpretation, the evidence EPA has cited regarding CO_2 emissions from EGUs in the proposed subpart TTTT– including the fact that "fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions, and constitute by far the largest single stationary source category of GHG emissions,"– more than amply demonstrates that these emissions contribute significantly to dangerous air pollution from GHGs. *See id.* at 1456.

[151] While we agree that the agency only needs a rational basis in order to regulate a pollutant emitted by an already listed source category, the threshold decision to regulate a pollutant must remain faithful to Congress's intent that EPA establish standards of performance for source categories that "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A). Other factors such as cost and non-air quality health and environmental impacts are properly considered at a later stage, when selecting BSER. *See id.* § 7411(a)(1).

Finally, we agree with EPA that it is not necessary in this rulemaking to determine a lower limit for what constitutes a "significant" contribution. When litigating EPA's decision not to reconsider the 2009 Endangerment Finding, industry and state petitioners argued that the Finding was invalid because EPA did not define a threshold distinguishing non-endangerment from endangerment. The D.C. Circuit soundly rejected this position:

> EPA need not establish a minimum threshold of risk or harm before determining whether an air pollutant endangers. It may base an endangerment finding on "a lesser risk of greater harm . . . or a greater risk of lesser harm" or any combination in between." . . . [EPA's] failure to distill this ocean of evidence into a specific number at which greenhouse gases cause "dangerous" climate change is a function of the precautionary thrust of the CAA and the multivariate and sometimes uncertain nature of climate science, not a sign of arbitrary or capricious decision-making.

Coal. for Responsible Regulation, 684 F.3d at 123. Similarly, EPA need not identify what source categories might *not* contribute significantly to dangerous air pollution, given that the category at issue clearly *does* contribute significantly. In the 2009 Endangerment Finding, EPA determined that section 202(a) emissions contribute to endangerment. In doing so, the agency noted:

> [T]he 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. at 66,499.

If section 202(a) emissions, "judged by any standard, . . . make a meaningful contribution to greenhouse gas concentrations and . . . global warming," as the Supreme Court has held, then it is necessarily true that the even larger emissions from EGUs contribute significantly to dangerous GHG pollution and the resulting problem of climate change. 549 U.S. at 525. While neither the 2009 Endangerment Finding nor *Massachusetts v. EPA* addressed the word "significantly" as it appears in section 111, it is reasonable for EPA to conclude that a source category contribution that exceeds the emissions from any other category is both "meaningful" and "significant[]."

VI. Categorization and Sub-Categorization of EGUs

A. EPA Should Group All Fossil Fuel-Fired Power Plants, Including Electric Utility Steam-Generating Units and Stationary Combustion Turbines, in a Single Category, and Should Create Subcategories As Needed.

In its proposed rule, EPA has included "a proposal and, in the alternative, a co-proposal, which take two different approaches to the source categories and their codification." 79 Fed. Reg. at 1454. First, EPA has proposed "to codify the new CO_2 standards in the same subparts in which standards of performance for conventional pollutants are codified" and to maintain "the two source categories—steam-generating boilers and stationary combustion turbines—that EPA has already listed." *Id*. Under its current regulatory structure, electric utility steam-generating units (including IGCC facilities) are covered under 40 C.F.R. Part 60's subpart Da, while stationary combustion turbines fall under subpart KKKK. The first proposal would therefore retain these two categories. Second, EPA "co-proposes to combine the two source categories—again, steam-generating boilers and combustion turbines—for purposes of regulating CO_2 emissions (but not for regulating emissions of conventional pollutants), and to codify all of the proposed regulatory requirements in a new subpart, TTTT." *Id.*

Joint Environmental Commenters urge EPA to combine the existing categories into a new category, subpart TTTT, that includes the coal- and gas-fired units covered under the current proposal. The new category should also reflect the current applicability definitions, that is, should include all fossil fuel-fired power plants with a capacity to generate more than 25 MW of net electrical output (or more than 219,000 MWh annually) and that either have been design to supply to or actually supply any amount of electricity to the grid. As we discuss below, this category should cover baseload, intermediate-load, and peaking units alike.

Furthermore, if EPA finalizes a new category TTTT, EPA should in a future rulemaking reorganize its existing regulations to cover emissions of criteria pollutants from under category TTTT as well. Section 111 requires EPA to review its performance standards for each source category at least every eight years, and to make any revisions that may be appropriate (including issuance of performance standards for pollutants not previously covered). EPA's current co-proposal would establish one regulatory category to cover CO_2 emissions from fossil fuel-fired power plants (codified in subpart TTTT), while leaving separate categories (subparts Da and KKKK) to cover criteria pollutant emissions from electric utility steam-generating units and stationary combustion turbines, respectively Not only would this introduce unnecessary confusion into the regulations, it would create a situation in which EPA would conduct its periodic review for these sources on different tracks depending upon the particular kind of pollutant at issue. To ensure that EPA undertakes its reviews for fossil fuel-fired EGUs in a manner that is both timely and coordinated, EPA should incorporate performance standards for criteria pollutants in subpart TTTT as well.

Joint Environmental Commenters note that for steam EGUs, EPA revised its performance standards for criteria pollutants in February 2012. *See* 77 Fed. Reg. 9304 (Feb. 16, 2012). We do not contend that EPA must revise those standards prior to 2020; rather, we urge EPA to reorganize them administratively into new subpart TTTT, should the Agency finalize it. As for stationary combustion turbines, EPA last finalized its performance standards for criteria pollutants in July 2006, *see* 71 Fed. Reg. 38,482 (July 6, 2006), and published a proposed set of standards in August 2012, which it has yet to finalize. *See* 77 Fed. Reg. 52,554 (Aug. 29, 2012). We urge EPA to finalize these standards swiftly, as the eight-year regulatory period will expire in August, and encourage the agency to include them in subpart TTTT as well.

Within this broad category of fossil fuel-fired EGUs, EPA may establish appropriate subcategories. Thus, while we supported EPA's 2012 proposal for a single standard for intermediate and baseload units, Joint Environmental Commenters also support the agency's current decision to make separate BSER determinations for subcategories, including a subcategory for electric utility steam-generating units (which encompass IGCC facilities), and another subcategory for stationary combustion turbines.

1. Source Categories May Encompass Multiple Production Methods and Fuels.

The text of the Clean Air Act plainly grants EPA discretion to create a single category that includes all fossil fuel-fired EGUs. Section 111(b)(1)(A) directs EPA to designate "categor[ies] of sources . . . [that] cause[] or contribute[] significantly to air pollution which may reasonably be anticipated to endanger public welfare." The agency must revise its source category designations "from time to time," *id.,* and the statute permits EPA to "distinguish among classes, types, and sizes within categories of new sources." 42 U.S.C. § 7411(b)(2). This grant of authority to create (or not create) subcategories confirms that a source category may include different "classes, types, and sizes" of sources. This provision permits the merger of all or part of two existing categories. There is nothing in the statutory language that precludes the agency from changing or combining categories that have already been listed, so long it has a rational basis for doing so.

Categorizing sources by function, as we recommend, is consistent with the legislative history of the Clean Air Act. In 1970, Congress emphasized that EPA could create broad industrial categories, explaining the agency "could establish uniform pollution control standards for the chemical, oil refining, foundries, food processing, and cement-making industry, and other industries. . . . Every plant within the same group could be required to maintain the same high standards." 116 Cong. Rec. 19,218 (1970) (statement of Rep. Vanik). EPA has, in fact, frequently established broad categories encompassing multiple types of sources that serve the same function. As early as 1976, EPA designated a single NSPS for multiple copper smelting production methods.[152] Since then, numerous other standard-setting rules have categorized sources by function, even while the covered sources included use different technologies, fuels, or processes. For instance, in 1982, EPA established a single category for rotary lime kilns that

[152] 41 Fed. Reg. 2332-2333 (Jan. 15, 1976).

covered varied types of kilns, including those fueled by coal, natural gas, and oil.[153] More recently, EPA included all Portland cement plants (*e.g.* "long wet," "long dry," "preheater," and "preheater with precalciner") in a single category,[154] a decision ultimately upheld by the DC Circuit. *Portland Cement III,* 665 F.3d at 190-93. *See also* 40 C.F.R. § 60.62(a).[155]

EPA has also merged existing categories to reorganize them according to the function served. For example, IGCC plants were previously included in a different category from steam-generating boilers. In 2005, EPA moved IGCC plants to the steam-generating boiler category (subpart Da) on the ground that they serve the same function. *See* 77 Fed. Reg. 22392, 22,411/1 (April 13, 2012). As these examples demonstrate, EPA may—and frequently has—grouped sources that use different processes or fuels in the same category, even when one process can meet a more stringent standard than the other, or can meet the same standard at lower costs.

2. All Fossil Fuel-Fired Power Plants Should Be Included In the Same Category Because They Serve the Same Function, And Doing So May Simplify Frameworks to Secure Cost-Effective Carbon Reductions From Existing Units.

As discussed above, EPA is authorized to determine how to categorize sources under section 111. In this case, there are two primary reasons why EPA should create a single category including all fossil fuel-fired power plants. First, creating such a category will pull together all listed sources that serve the same electricity generating function. As described in section II, *supra*, the electricity sector has changed dramatically in recent years, and natural gas-fired plants now provide substantial quantities of baseload and intermediate load power. As such, these units serve the same load-serving function as steam EGUs, and would thus logically fall within a single category. However, we assert that a single subpart TTTT should not be limited to baseload and intermediate load plants, but should encompass all fossil fuel-fired power plants that form part of our electricity generating system, including peaking plants. As we note in section IX.B.1, we urge EPA to create a subcategory and set a separate standard for new peaking plants in addition to new baseload and intermediate load units.

[153] 47 Fed. Reg. 38832, 38843 (Sept. 2, 1982); *see also* 40 C.F.R. §§ 60.340(a), 60.342.

[154] 75 Fed Reg. 54970, 55,010-55,012, 55,015 (Sept. 9, 2010).

[155] EPA has also created categories based on function, rather than on fuel or method of operation, under the section 112 National Emission Standards for Hazardous Air Pollutants ("NESHAP") program, which uses language similar to section 111 in directing EPA to list "categories and subcategories" of sources. For example, in promulgating a NESHAP for hardboard composite wood product processing, EPA adopted a single standard for multiple production methods, a decision upheld by the D.C. Circuit. *NRDC v. EPA*, 489 F.3d 1364, 1375 (D.C. Cir. 2007) (citing 69 Fed. Reg. 45,944 (July 30, 2004)). In the rulemaking, EPA determined that equipment should be classified "according to its function," which includes considerations of the end product and the market in which that product competes. *Id.* (citing 69 Fed. Reg. 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, attached as **Ex. 52**.

Second, establishing an inclusive category in this rulemaking under section 111(b) could simplify the forthcoming 111(d) standards for carbon pollution from existing power plants. Combining categories would simplify implementation of a system-based approach to achieving the emission reductions required under section 111(d), should EPA (in its forthcoming emission guidelines) or states (in their SIPs) choose to adopt such an approach. Although nothing in the text of section 111(d) requires that standards for existing sources replicate the category framework into which EPA organizes new sources (so long as "a standard of performance under this section [111] would apply" if a proposed 111(d) source "were a new source"), it makes sense for EPA to consider both the new and existing source rules when it establishes or revises a 111(b) rule. In this case, establishing a single category for all fossil fuel-fired EGUs in the context of section 111(b) rule may simplify EPA's and states' efforts to achieve significant emission reductions from power plants pursuant to section 111(d).

Utilities and independent system operators make dispatch decisions for the entire fleet of power plants without regard to whether those power plants are fueled by coal, natural gas, nuclear energy, or renewable resources. Operating the grid in this way allows utilities to dispatch the least expensive available generating resources. States and utilities may choose to consider compliance options for EPA's forthcoming 111(d) standards that follow similar principles. While EPA has not yet proposed emission guidelines under section 111(d), to the extent that those guidelines incorporate a system-based approach to carbon pollution reductions, a single category for fossil fuel-fired EGUs can simplify the implementation of compliance options that look to the whole fleet of existing power plants. Accordingly, EPA should consider this in determining whether to finalize a new category TTTT encompassing all fossil-fired power plants

3. EPA Should Set Standards for Peaking Plants and Should Use Functional Criteria to Distinguish Among Power Plants.

Under its current co-proposal for subpart TTTT, EPA seeks to exempt peaking plants from the category and from regulation. As a functional matter, it defines peakers as those that have been designed to supply, and that actually supply, more than one-third of their potential electric capacity for sale to the grid on a three-year rolling average basis. *See* 79 Fed. Reg. at 1511 (proposed 40 C.F.R. § 60. 5509(a)(2)). As discussed above and in section VII.B.2, Joint Environmental Commenters strongly urge EPA to include peaking plants in the combined TTTT category and to set standards for such plants as a subcategory. We also urge the agency to define peaking units as units that operate fewer than 1,200 hours per year. EPA must also ensure that distinctions among combustion turbine power plants are based on function (as determined by annual hours of operation), not on purpose or technology.

Additionally, the current regulations under subpart KKKK apply to all non-IGCC stationary combustion turbines with a heat input of 10.7 gigajoules (10 MMBtu) per hour or greater. 40 C.F.R. § 60.430. In its proposed revisions to this subpart, as well as in the language for the proposed subpart TTTT, EPA specifies that the CO_2 standard for stationary combustion turbines will apply if, among other criteria, a plant "was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output [annually] to a utility distribution system on a 3 year rolling average basis." 79 Fed. Reg. at 1511 (proposed 40 C.F.R. § 60.5509(a)(2)). This would allow a plant that was constructed for industrial purposes to avoid the application of the standards even if the plant actually supplied more than one-third of its output capacity—or, indeed, 100 percent of its output capacity—and more than 219,000 MW annually. There is no justification for EPA to allow such a loophole in the standards. If the owner of a simple cycle plant designed for peak use decides to operate the plant as an intermediate load plant, it should comply with the standards for plants that serve that function. Accordingly, we recommend that EPA distinguish between the subcategories of peaking plants, intermediate/load-following, and baseload combustion turbines based on their actual hours of operation.

VII. Applicability of the Proposed NSPS and the Proper Definition of EGUs

The applicability provisions of the proposed NSPS, as well as its definition of regulated sources, are critical components of the rule, and the manner in which EPA addresses these issues have major implications for the rule's efficacy. For these reasons, Joint Environmental Commenters propose a number of changes to EPA's approach to these issues. Our recommendations, if adopted, will close significant loopholes that now exist in the proposed rule and will help the performance standards achieve maximum effectiveness in reducing CO_2 emissions from fossil fuel-fired EGUs. Discussed in detail below, our recommendations are as follows:

- The agency must retain the definitions in the EGU applicability provisions that exist in the current regulations for subpart Da, as well as those for subparts Db and Dc, which regulate smaller steam EGUs and gasification plants that do not utilize combined cycle technology. In addition, it should close off loopholes that exist in both the current regulations and proposed rules.
- EPA should abandon its proposal to re-define EGUs so as to exclude any unit from regulation unless it is designed to supply, and actually supplies,[156] more than one-third of its potential electric output capacity and 219,000 MWh annually to the grid. Instead, it should continue to provide specific calculation procedures for emissions from regulated cogenerating facilities, and should apply the standards to all EGUs that supply or were constructed for the purpose of supplying *any* electricity for sale to the grid.
- EPA should also ensure that fast-start CCGTs are covered under the proposed NSPS.

[156] The "purpose of construction" language appears in the proposed revisions to subpart KKKK but not subpart Da, whereas the "actually supplies" language appears in EPA's revisions for both subparts. 79 Fed. Reg. at 1502 (proposed 40 C.F.R. § 60.46Da(a)(2)), 1506 (proposed 40 C.F.R. § 60.4305(c)(5)). The proposed subpart TTTT includes both the "purpose of construction" and "actually supplies" provisions. 79 Fed. Reg. at 1511 (proposed 40 C.F.R. § 60.5509(a)(1)-(2)).

- EPA should revise its proposed rule to ensure that the individual gas combustion turbines and the HRSG at CCGT plants are not treated separately for the purposes of determining applicability or calculating emissions. To reflect the agency's determination that CCGT is BSER for gas and oil-fired EGUs, EPA should set emission limits for gas- and oil- fired EGUS, including the combustion turbines and any HRSG that are associated with those turbines, based on the demonstrated performance of the best existing and anticipated new CCGTs, rather than setting separate applicability emission limits for the combustion turbines and HRSGs that make up CCGTs.
- EPA should establish ensure that all components of CCGTs are covered under a single subcategory, which would also include CTs.
- EPA should not exclude peaking simple cycle combustion turbines ("CTs") or CCGTs from regulation. Instead, it should promulgate a three-tiered set of performance standards under which peaking units (i.e., those operating fewer than 1,200 hours annually)—whether CT or CCGT—would be limited to 1,100 lbs CO_2/MWh. (Emission limits for peaking, load-following, and baseload plants are discussed in section IX.B.2, *infra*.)
- We urge EPA not to redefine "affected facility" so as to permit EGUs to include in their emissions calculations electricity generated by co-located technology that is not integrated into the regulated unit as an engineering matter.
- EPA should not create a separate emission limit for smaller CCGTs (i.e., those with a maximum heat input under 850 MMBtu/h). If it nevertheless chooses to do so, it should set a standard for these units that does not exceed 1,000 lb CO_2/MWh. Under this scenario, EPA must also provide that multiple smaller units at the same physical site will be considered a single source for the purpose of calculating emissions.

A. EPA's Proposed Applicability Provisions Are Unworkable, Unwise, and Arbitrary.

Part 60, subpart Da currently applies to each steam EGU (including each IGCC unit) that is "capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel (either alone or in combination with any other fuel)." 40 C.F.R. § 60.40Da(a), (b). An EGU is defined as a unit "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 the grid. *Id.* § 60.41Da. A coal-fired EGU is one that burns coal, irrespective of amount or of co-fired fuels. *Id.* Thus, a source falls within Subpart Da if it is large enough (exceeds 73 MW) and is not exempt under section 60.41Da's "purpose of construction" provision. A gas turbine is subject to Part KKKK if it has a heat input at peak load of 10 MMBtu/hour or greater; there is no analogous "purpose of construction" provision in this subpart. *Id.* § 60.4305. Under these current regulations, all parties can determine prior to construction and permitting whether the NSPS applies, and hence will serve as a floor for the best available control technology ("BACT") determination that will be made during preconstruction permitting under the CAA's Prevention of Significant Deterioration ("PSD")/New Source Review ("NSR") program. Pursuant to EPA's "once in, always in" policy, the NSPS limits are thereafter binding on the facility as long as it continues to operate.[157]

EPA has proposed to alter this structure in several significant ways, but has not identified a reason why regulation of CO_2 emissions requires such a change. We list EPA's proposed revisions below.

- EPA's proposed rule amends subpart Da such that an electric utility steam generating unit does not qualify as a regulated EGU unless it supplies more than one-third of its potential electric output and more than 219,000 MWh (net) to the grid on an annual basis. 79 Fed. Reg. at 1502 (proposed 40 C.F.R. § 60.46Da(a)(2)).
- EPA further proposes to amend subpart KKKK such that any stationary combustion turbine (again, whether simple cycle or combined cycle) would not be subject to regulation unless it combusts over 90 percent natural gas on a three-year rolling average basis. 79 Fed. Reg. at 1506 (40 C.F.R. § 60.4305(c)(4)). As such, a unit that co-fires more than 10 percent of some other fuel, such as oil, blast furnace gas, landfill methane, or syngas from coal, would not be subject to regulation under subpart KKKK.
- Under the proposed rule, a source is not a regulated EGU unless it actually combusts more than 10 percent fossil fuel during three consecutive calendar years[158] on a heat-input basis. 79 Fed. Reg. at 1502 (proposed 40 C.F.R. § 60.46Da(a)(1)), 1506 (proposed 40 C.F.R. § 60.4305(c)(3)). As such, it would permit sources large enough to require NO_x and/or SO_2 emission limitations immediately upon commencement of operation to defer the applicability of the CO_2 emission limits for three years until the first average can be calculated, with the result that the standard may or may not apply in subsequent years, depending on the use of the facility in the relevant averaging period.
- The proposal also amends subpart KKKK such that a stationary combustion turbine (whether a simple cycle CT or a CCGT) does not qualify as a regulated EGU unless it was constructed for the purpose of supplying, and actually supplies, more than one-third of its potential electric output and 219,000 MWh (net) annually to the grid on a three-year rolling annual average basis. 79 Fed. Reg. at 1506 (proposed 40 C.F.R. § 60.4305(c)(5)). Similarly, the proposed subpart TTTT would cover only those sources

[157] *See* Letter from Edward E. Reich, Director, EPA Division of Stationary Source Enforcement, to Tom Devine, Director, EPA Air & Hazardous Materials Division, Region IV, Re: Applicability of NSPS to Oil-Fired Boilers Converting to COM (Nov. 27, 1979), *available at* http://www.epa.gov/oecaadix/pdf/adi-nsps-d092.pdf, attached as **Ex. 53.**

[158] Under proposed subpart TTTT, the 10 percent fossil fuel threshold would be determined on a three-year rolling average basis, rather than a calendar year basis. *See* 79 Fed. Reg. at 1511 (proposed 40 C.F.R. § 60.5509(a)(1)-(2)).

(steam EGUs and stationary combustion turbines) that satisfy these conditions. 79 Fed. Reg. at 1511 (proposed 40 C.F.R. § 60.5509(a)(1)-(2)).

These revisions are problematic for a number of reasons. Under EPA's proposal, a source would no longer be subject to the NSPS if it fell below the threshold for any of the applicability metrics that are calculated on a three-year (or, in some cases, annual) basis. This would create a situation in which no one would know whether a particular plant will be subject to the standards at all until years after the emissions had already occurred. Furthermore, because a number of the proposed applicability provisions apply on a rolling basis, plants operating near the threshold could move in and out of the regulatory system from one month to the next. Not only would this create significant practical problems for compliance and enforcement purposes, it would add unnecessary complication to Title V[159] and PSD permitting as well, since authorities would not know whether certain sources would or would not be subject to the NSPS until well after those plants had been operating for several years, and would not have a proper basis to establish a BACT floor for those units. EPA has suggested that sources need flexibility in their operations. We agree that there may be areas, such as those addressed in EPA's tailoring rule, where CO_2 emissions are treated differently than SO_2 or NO_x, but EPA has not attempted to demonstrate a reason for such a difference in these provisions.

Joint Environmental Commenters propose a three-tiered system that establishes separate performance standards for peaking, intermediate/load-following, and baseload EGUs, respectively. *See* section IX.B.2, *infra*. Because these would be determined on the basis of annual operating hours, it is true that regulated sources would have to manage their operations so as to comply with the limit that they choose to meet. However, many sources routinely do so to avoid major source thresholds under the PSD program, or the different emission limitations in the existing NSPS for criteria pollutants. Alternatively, a plant could avoid any operational constraints by installing efficient equipment to provide a compliance margin that is sufficient to meet the most stringent standard that might realistically apply given the source's intended business plan, and would commit to any such emission limitation in its Title V permit. However, the key determination of whether the NSPS would apply *at all*—regardless of the actual emission limitation—would be determined *ab initio*.

EPA's proposed applicability exemptions are potentially problematic in the context of the agency's pending 111(d) rule for existing power plants. Since the NSPS are a predicate for regulating existing sources under section 111, broader coverage under the NSPS will clarify that they will be included in the standards under section 111(d). This would ensure the agency can limit emissions from old, inefficient units that are operating at capacity factors of less than 0.33. Perversely, the proposal might encourage greater utilization of these units (up to the 33 percent limit), if their emissions were left unregulated. Whether the new source standards will apply to a particular unit should be determined based upon the same applicability provisions now in place for criteria pollutants (with certain exceptions we discuss below). Moreover,

[159] Title V refers to the CAA's operating permit program and state-level analogs. *See* 42 U.S.C. §§ 7661-7661f.

applicability should be determined *prior* to the source's construction, and should remain in effect throughout the source's lifetime.

In addition, the proposed rule's applicability to a given source would be determined by a three-year rolling average of generation data for several threshold values. This is necessarily a retrospective determination of a source's legal obligations, violations of which might generate penalties for the U.S. Treasury.[160] However, since an interested member of the public must demonstrate an ongoing violation in order to bring a citizen suit, and a prospective obligation cannot be determined with certainty, it may be difficult for concerned citizens to bring a suit for violation of these provisions. As such, EPA's proposed regulations undermine citizen enforcement, a critical component of the Clean Air Act.

Finally, Joint Environmental Commenters note that, under the proposed rule, a CCGT or CT would not be regulated under subpart KKKK if it fired less than 90 percent natural gas on a three-year rolling average basis. *See* 79 Fed. Reg. at 1506 (proposed 40 C.F.R. § 60.4305(c)(4)).[161] If such a facility were a CCGT that burned at least 50 percent syngas, it would fall within the proposed regulatory definition of IGCC, and would thus be covered under subpart Da. See 79 Fed. Reg. at 1506 (proposed 40 C.F.R. § 60.40Da(k)) (defining "IGCC facility" as an "*integrated gasification combined cycle electric utility steam generating unit*, which means an electric utility combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas . . . .") (italics in original). However, a CCGT combusting solid-derived fossil fuel is, in essence, a coal-fired power plant. This proposed definition would allow an IGCC to obtain up to 50 percent of its heat input from coal without having to meet the emission limit reflecting the use of partial CCS, while a pulverized coal plant, such as an AUSC unit that combusts 10 percent or more coal, would be covered.[162]

As proposed, a CCGT that burned less than 50 percent syngas and 90 percent or less natural gas would escape regulation altogether, since it would qualify as neither an IGCC or a natural gas-fired CCGT. These exemptions would include plants whose fuel mix consisted of 45 percent syngas and 55 percent natural gas, or 85 percent natural gas and 15 percent oil. Likewise, the proposed rules would not cover any CT that burned 90 percent or less natural gas, regardless of its heat input from syngas. IGCCs should be required to operate on an even footing with other steam EGUs that combust coal, and be subject to the same 10 percent test as other coal-fired plants in Subpart Da and Subpart TTTT. To fully eliminate these loopholes, EPA should adopt the applicability provisions we describe below.

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[160] One can anticipate a defense that the violating source could not anticipate that it would exceed or be subject to the applicable threshold, or that there was an accounting error that underestimated how much electricity it would generate over the course of the compliance period.
[161] Supbart TTTT includes an analogous provision for stationary combustion turbines. *See* 79 Fed. Reg. at 1511 (proposed 40 C.F.R. § 60.5509(a)(2)).
[162] The uncertain effect of a 50 percent threshold is further complicated by the selection of partial, rather than full, CCS as BSER.

B. EPA Should Retain the Standard Definition of Electric Generating Units that Appears in the Existing Regulations Under Subparts Da and KKKK, But Should Include Revisions that Better Address CCGTs and Close Potential Loopholes.

Under the NSPS regulations currently in place, the applicability and stringency of the emission limits are not based on how frequently a unit is used, but on its maximum heat input capacity. Thus, the applicability of the NSPS is known at the time the unit commences operation. Subpart Da currently excludes steam EGUs that are not capable of combusting more than 73 MW (250 MMBtu/hr) of heat input. 40 C.F.R. § 60.40Da(a)(1). Subpart KKKK excludes very small combustion turbines incapable of combusting at least 10.7 GJ/hr (10 MMBtu/hr), and provide for varying emission limits based on either the unit's maximum heat input or its maximum electric output. *See id.* §§ 60.4305(a), Pt. 60, Subpart KKKK, Table 1. These provisions have proved workable for several decades, and we encourage EPA to retain this basic structure in the new rule. Below, we discuss ways in which EPA should strengthen the existing applicability provisions with language to foreclose potential loopholes.

1. The GHG NSPS Should Provide Specific Provisions for Regulated Co-Generating Sources and Should Cover All Other Sources that Actually Supply or Are Designed to Supply Any Amount of Electricity to the Grid.

Under the current regulations, Subpart Da exempts certain commercial and industrial boilers through its definitions for "electric utility combined cycle gas turbine" and "electric utility steam generating unit." Under these definitions, an affected unit is one that is "constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electric output to any utility power distribution system for sale." 40 C.F.R. § 60.41Da. The "potential electric output capacity" of a unit is simply the unit's maximum annual electric output assuming the maximum hourly heat input and a prescribed generation[163] efficiency of 33 percent. *See id.* Thus, this term is also based on the "size" of the unit's theoretical generation capacity that is available to sell electricity to the grid and does not depend on how the unit is operated. Sources that meet the heat input thresholds but are not constructed for the purpose of supplying the requisite amount of electricity to the grid are subject to Subpart Db or Dc. As such, the current regulations operate such that the source, the permitting and enforcement authorities, and the public all know in advance which emission limit applies to any given EGU.

In the current NSPS proposal, EPA has proposed a new definition for EGUs ostensibly in response to a potential loophole in the existing regulatory structure: the possibility that changing business conditions may make it more profitable for the operator of a source that was intended to operate as an industrial unit subject to Subpart Db to sell extra electricity to the grid while avoiding the emission limits that apply to plants that were designed "for the purpose

[163] EPA proposes to allow a source to use the rated efficiency of the actual unit. *See* 79 Fed. Reg. at 1446.

of" supplying a certain amount of electrical output to the grid.[164] EPA is right to be concerned with this issue, as it appears that it is not a hypothetical problem.[165] However, the agency's proposed remedy—requiring that regulated units "actually sell" at least one-third of their maximum output capacity and 219,000 MWh annually—does not resolve the issue. Rather, it would pose a much larger problem by (1) creating a situation in which source operators, permitting and enforcement authorities, and the public will not know whether a source is in compliance until the end of the averaging period; (2) exempting peaking units that are not industrial units and have no cogeneration purpose or capacity; and (3) complicating regulation of existing coal- or gas-fired units that operate at capacity factors of less than one-third, since the existence of applicable section 111(b) standards are a predicate for regulation by states under section 111(d).

As described previously, EPA proposes to limit the scope of the proposed NSPS to those sources that are not only *designed* to supply, but also *actually supply,* at least one-third of their potential electric output and 219,000 MWh annually to the grid. *See* 79 Fed. Reg. at 1506 (proposed 40 C.F.R. § 60.4305(c)(5)), 1511 (proposed 40 C.F.R. § 60.5509(a)(1)-(2)), 79 Fed.Reg. at 1502 (proposed 40 C.F.R. § 60.46Da(a)(2)).[166] This proposed revision would not cure the problem of aluminum manufacturers' changing business model (*see* n. 165), since each facility would still have been constructed for some purpose other than providing more than one-third of its potential electric output to the grid. Instead, as proposed, a source that was originally constructed for a different purpose would be exempt from the rule even if it actually supplied more than one-third of its potential electrical output and 219,000 MWh annually to the grid over the averaging period. Similarly, a source constructed to operate as an EGU would be exempt if it ultimately supplied less than the prescribed amount for sale to the grid.

EPA should address the applicability issues associated with changing business opportunities and with source operators misrepresenting the true purpose of projects by retaining the existing provisions for calculating emissions from cogeneration facilities (i.e., those that generate both useful heat and electricity), rather designing regulations that cover

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[164] A related concern is that an operator might misrepresent the true purpose of the unit in order to avoid the more stringent emission limits.

[165] Joint Environmental Commenters understand that at times in the past few years, aluminum prices fell so low that aluminum producers could make more money selling electricity generated onsite than aluminum.

[166] As noted previously, the proposed revision of Subpart Da omits reference to the source's design purpose, but simply defines an affected facility as one that "supplies more than one-third of its potential electric output and more than 219,000 MWh net-electric output to a utility power distribution system for sale on an annual basis." 79 Fed. Reg. at 1502 (proposed 40 C.F.R. § 60.46Da(a)(2)). We assume this to be a drafting error on the agency's part, as subparts KKKK and TTTT include both the design purpose and "actually supplies" language in their applicability provisions, and calculate the threshold figures on a three-year rolling average basis. *See* 79 Fed. Reg. at 1506 (proposed 40 C.F.R. § 60.4305(c)(5)), 1511 (proposed 40 C.F.R. § 60.5509(a)(1)-(2)). Since Subpart TTTT is supposed to be merely an alternate form of codification, we assume that EPA intends to retain the "constructed for the purpose" test for applicability under Subpart Da.

only those facilities that are *not* cogeneration units while also excluding some sources that should be covered. Precedent for this approach is found in EPA's treatment of cogeneration units in the Acid Rain Program regulations.[167] The GHG NSPS should also include a specific "opt-in" provision such that any facility, regardless of its initial purpose to operate as a cogeneration facility, may elect in advance to be a cogeneration unit subject to the regulations. This opt-in provision would also provide that any cogeneration facility is covered by these regulations at all times after any single year during which it provided more any electricity to the grid. These concepts are consistent with the Acid Rain Program's rules and with EPA's "once in, always in" policy that dates back to at least 1979.[168] Any unit should be covered by the proposed regulation if it is constructed for the purpose of selling *any* electricity to the grid, or if it actually sells any electricity to the grid regardless of its original purpose.

The criteria for determining whether a unit is subject to Subpart Da or Subparts Db/Dc are particularly significant in light of the fact that EPA has not proposed CO_2 emission limits for Subpart Db or Dc units. Neither EPA's current nor its proposed definition of a regulated EGU properly distinguishes between cogeneration and commercial, non-utility generation. Cogeneration involves the simultaneous generation of heat and electric power and is generally favored because the use of waste heat provides greater efficiency and reduced emissions. Many large manufacturing facilities utilize electric generating units whose primary purpose is to generate electricity for onsite use, and these units may or may not have cogeneration capacity. EPA's proposed exemption, however, is based not on a source's cogeneration capability, but on whether the electricity is used on-site or off-site. To the extent EPA believes that it may and should change the terms for applicability of subpart Da rules for the purposes of the GHG NSPS, we recommend that new large electric generating units that do not have significant cogeneration capacity be included in the proposed regulations irrespective of whether the electricity is used on-site or is provided to the grid. Absent such a change, one can imagine that a consortium of companies may form to purchase electricity directly from new coal-fired plants or CCGTs that do not comply with otherwise applicable limits. And, as discussed above, we recommend that EPA revise its rule to cover any unit that is designed to supply or actually supplies *any* amount of electricity to the grid.

2. All Components of CCGTs Should Be Covered by a Single Subcategory, Which Should Also Include CTs

EPA's existing regulations treat heat input at, and emissions from, combined cycle facilities in a confusing and counterintuitive fashion. The agency should amend its approach with the GHG NSPS to ensure that *all* heat input associated with these facilities is considered for the purposes of applicability, and that all their emissions are regulated under a single performance standard. From an engineering standpoint, CCGTs operate in two stages. First, gaseous or liquid fuel is burned in one or more a combustion turbines, which generate

[167] *See* 40 C.F.R. § 76.2 and App. D. *See also* EPA, Technical Support Document for the Final Clean Air Interstate Rule, *available at* http://www.epa.gov/CAIR/pdfs/tsd_cogen.pdf, attached as **Ex. 54.**
[168] *See* Reich letter to Devine, *supra* note 157.

electricity. Second, the waste heat from this process is routed through a heat recovery steam generator ("HRSG"), which in turn produces steam that is delivered to a turbine, generating additional electricity. HRSGs also often receive additional heat input from burners within the HRSG that may fire a variety of fuels, from duct burners, and, in recent years, from concentrated solar power ("CSP") thermal units; *see* section VII.B.5, *infra*).

Subpart KKKK covers "stationary combustion turbines," and the rule proposal defines this term to include all integrated equipment in a facility, including both the combustion turbine and HRSG for a CCGT unit. *See* 79 Fed. Reg. at 1510 (proposed 40 C.F.R. § 60.4421). However, the existing subpart KKKK regulations provide that "[o]nly heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input." 40 C.F.R. § 60.4305(a). However, the regulation goes on to specify that "subpart does apply to emissions from any associated HRSG and duct burners." *Id.* Nothing in the proposed rule appears to override these existing provisions. Accordingly, under the GHG NSPS, the heat input to a CCGT's HRSG or duct burners would not count for applicability purposes under subpart KKKK, but emissions associated with those units would count if the facility were to fall within the scope of that subpart.

The existing language in subpart Da complicates this scheme. 40 C.F.R. § 60.46(e), which appears unaffected by the proposed NSPS, currently includes the following language:

> Applicability of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as [follows:]
>
> > (1) Affected facilities (i.e. heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (i.e. heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.
> >
> > (2) For heat recovery steam generators used with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (i.e. duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part.)

With this provision, EPA appears to be seeking to address emissions from fired HRSGs that do not fall within the regulatory scope of subpart KKKK. Yet the provision excludes from subpart Da's scope any HRSG that "*meets the applicability requirements* of and is subject to subpart KKKK of this part." Id. (emphasis added). As discussed above, emissions from combusting fuel in HRSGs and duct burners are excluded from consideration in applicability determinations under subpart KKKK. At the very least, this language is ambiguous and confusing. Furthermore, in section 60.46(e)(2), the rules contemplate a scenario in which emissions from a CCGT's burners would be subject to subpart Da's emission limits while emissions from its combustion turbine would be subject to subpart KKKK's (or GG's) limits.

While there may have been a rationale for doing so in the context of PM, SO_2 and/or NO_x emissions, there is no reason to continue this approach for CO_2 emissions from gas-fired CCGTs.[169] The earlier approach would only be workable if the emission limits for under Subpart Da are the same as those under Subpart KKKK. Joint Environmental Commenters are concerned that this issue may be one of the factors that is influencing EPA's selection of the emission limits for CCGTs.

A CCGT will be most efficient when the capacity of HRSG and gas turbines are properly matched, and there are many different combinations of turbine/HRSG capacity offered for CCGT designs. Hence, if EPA were to differing emission limits for a plant's HRSG and its gas turbine, a variety of standards would apply to different CCGT designs, and such a bifurcated standard might provide perverse incentives that reduce the EGU's overall efficiency. In addition, a bi-furcated standard, becomes difficult to monitor, especially with a continuous emission monitoring system ("CEMS"), which is the preferred monitoring system. Further, much of the emissions data inform EPA's designation of CCGT as BSER for gas plants are CEMS data that only represent the final, combined emission rate from the unit and do not differentiate between emissions associated with distinct components of the system. Finally, EPA has not proposed the different emission levels for HRSG and gas turbines that would be needed to implement such a system.

EPA should abandon the bifurcated approach and establish emission limits for gas-fired EGUs (as recommended elsewhere in these comments) in which a plant's total CO_2 emissions are measured at the emission point(s) of the CT or combined CCGT system, as applicable. Under the approach recommended in these comments, the operator of a peaking unit, which may be either a CT or a CCGT, would determine compliance by measuring CO_2 emissions at the point they are emitted to the environment, rather than at some interim point within the process. EPA has adopted this approach for IGCC units, and should do so for CCGTs as well.

[169] There is also at least a theoretical reason why emissions from an oil-fired HRSG should be subject to the proposed subpart Da limits and treated differently from the emissions from a gas fired turbine at the CCGT. We note the EPA does not believe than any new oil-fired combined cycle turbines will be built during the relevant period, and it has not yet proposed any CO_2 emission limits for such plants.

Accordingly, EPA should include two revisions in the proposed rule. First, it should specify that *all* the heat input associated with a gas-fired CT or CCGT[170] should be counted for applicability purposes under the relevant subpart. Second, EPA should ensure that *all* emissions from gas-fired CCGTs are regulated exclusively under a single subpart (either Subpart KKKK or the analogous sections of Subpart TTTT), rather than under subpart Da. These changes would eliminate the ambiguity in the existing rules, would ensure efficient administration of the standards, and would foreclose the possibility of separate emission limits for separate components of a single CCGT facility. For these reasons, we also urge EPA to revise the existing regulations according to our recommendations in a future rulemaking.

3. EPA Must Ensure That Fast-Start Peaking and Intermediate-Duty CCGTs are Covered Under the NSPS.

There is a changing dynamic in the market that EPA must address. Until recently, CCGTs regulated under Subpart Da were commonly considered to be constructed for the purpose of supplying more than one-third of their potential electric output to the grid. However, in the past few years, new and efficient "fast start" CCGTs have come on the market. These units are designed for integration with renewable technology and for load-following and peaking applications; they can readily meet EPA's proposed performance standards, as well as the more stringent emission limits we suggest in these comments. There may be instances where an operator of a fast-start CCGT operator asserts that the unit is not intended to provide more than one-third of its potential electric output to the grid. Nonetheless, because the unit will supply *all* of the electricity it *actually intends to produce* for sale to the grid (even if that amount is less than one-third of the plant's potential output), it should properly be considered an EGU and should be regulated under the proposed NSPS.

Under our proposal, the NSPS would apply to any non-cogenerating facility that is either designed to supply or actually supplies *any* electricity to the grid; this would include fast-start CCGTs. However, should EPA retain some provision that excludes facilities whose grid sales fall below a certain threshold, we urge the agency to close a potential loophole for CCGTs by referring not to a plant's *potential* electric output, but to its *intended* electric output. Indeed, under the rules that now exist, the loophole created by section 60.41Da's reference to "potential electric output" permits certain fast-start CCGTs (i.e., those that do not fall within the scope of subpart KKKK but would otherwise satisfy subpart Da's applicability provisions) to evade the more stringent regulations for criteria pollutants included in Subpart Da, and instead qualify for coverage under either subparts Db or Dc. By replacing "potential" with "intended," EPA could close this loophole, and we urge the agency to do so.

[170] We note that we refer here to all CCGTs that are not IGCCs. Under our other proposed revisions, non-IGCC CCGTs would include all combined cycle units that are at least 73 MW and burn at least 10 percent fossil fuel, apart from those that burn 10 percent syngas or more (which would qualify as IGCCs).

4. EPA's Regulations Should Cover CTs and Peaking Units and Should Require Peakers as a Class to Have Efficient Designs.

With its proposed definition for EGUs, EPA appears to be seeking a way to exempt less-efficient peaking units, which are typically simple-cycle CTs. According to EPA, "[t]his proposed definition does not explicitly exclude simple cycle combustion turbines, but as a practical matter, it would exclude most of them because the vast majority of simple cycle turbines sell less than one-third of their potential electric output." 79 Fed. Reg. at 1459. The agency has also solicited comment on alternate formulations for this exemption, including an exemption based on the unit's capacity factor. The strong public policy arguments that support requiring new load-following and baseload gas-fired units to be as efficient as practicable are equally applicable to peaking units.

The agency attempts to distinguish between the efficiency capabilities—and thus the emission rates—of simple cycle CTs compared to CCGT units. However, CT technology is not BSER for gas fired electric generating units. Such units should not be exempt from GHG emission standards. Joint Environmental Commenters agree, however, that the emissions performance of CTs can match that of CCGTs in certain peaking applications where a unit is only operated for a few hours each day. EPA should address this issue by determining the emissions performance of the best technology in peaking applications and establish an NSPS for those units by establishing the appropriate limits for units that are willing to limit operations to true peaking applications. Moreover, the exemption EPA crafted for its proposal is far too broad. Rather than exempting only peaking units, which typically operate very few hours per year, the proposed rule would permit exemptions for new large facilities that plan to install batteries of small, inefficient units to operate up to 4,000 hours per year or more. According to EPA's apparent interpretation of the definition of an EGU, a unit's total potential electric output would be based on full load operation for 8,760 hours per year. This means that under the current proposal, a unit that operates at full load for less than 2,920 hours[171] would not be subject to the standard. Furthermore, EGUs often do not operate at full load. Accordingly, under the scheme now proposed, a plant operator could tweak a unit's load to avoid regulation. For example, a unit that operates at an average load of 75 percent could operate up 3,893 hours annually and still avoid the proposed regulations.

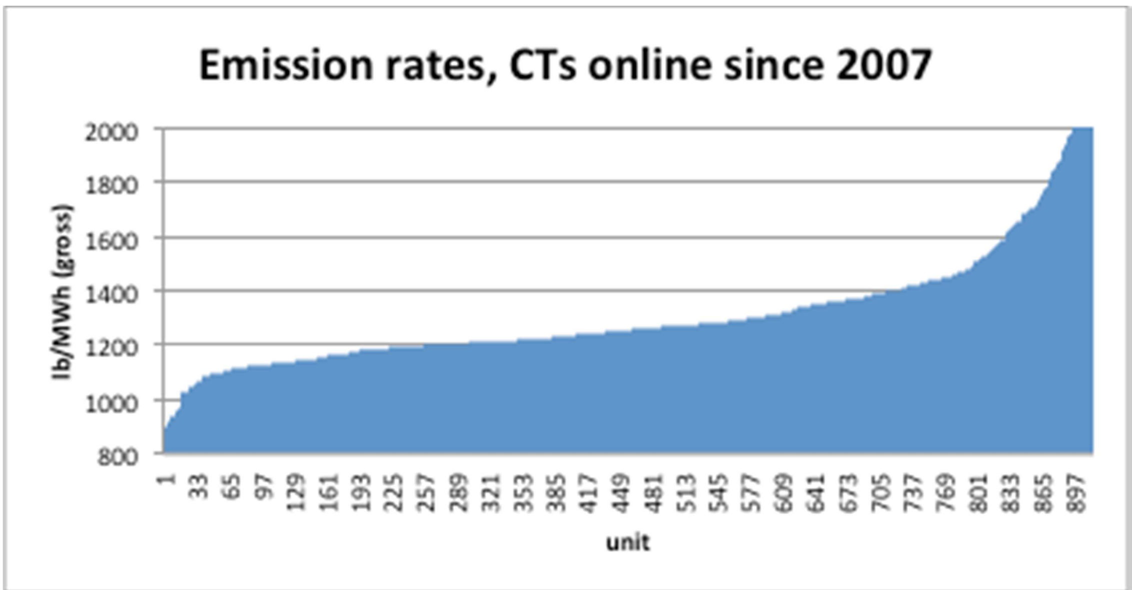
Exempting inefficient CT units that operate 4,000 hours or more a year from the performance standards would create a loophole to incentivize plant operators to serve the demand for renewable load-following generation with less efficient and dirtier CT technology. As discussed above, CCGTs are an available and technically feasible option to meet variable load-following demand. Joint Environmental Commenters therefore urge the agency to apply the rule to all sources, CT and CCGT alike, but to apply different emissions limits depending on the numbers of hours a unit operates annually. (For more discussion of these proposed emission limits, *see* section IX.B.2, *infra*). This tiered structure would provide a more lenient

[171] One-third of 8,760 hours is 2,920.

standard for peaking units while ensuring that baseload and intermediate/load-following needs are met with the best and most efficient technology available.

In the prior rulemaking, a number of the Joint Environmental Commenters submitted to the docket a compilation of data from EPA's Clean Air Markets Database ("CAMD")[172] for CTs that had come online after 2006.[173] Figure 6 below, which derives from these CAMD data, shows that the gross emission rates of these relatively "modern" CT units vary substantially. These data reveal that a large percentage of the units that began operating in the past few years have significantly higher rates than the most efficient units, with some emission rates as high as 2,000 lb CO_2/MWh. Under EPA's proposed rule, these units would be exempt if they operated at less than a 33 percent capacity factor over a three-year period.

Fig. 6: Emission Rates for CTs that Have Come Online Since 2007
Source: EPA, CAMD/AMPD



Joint Environmental Commenters can think of no public policy reason why the sale, construction, and operation of new inefficient peaking units should be permitted going forward, and EPA has offered none. A new peaking unit can be expected to remain in service for twenty years or more, and will emit substantial amounts of CO_2 over the course of its lifetime. While very few, if any, new coal-fired EGUs are likely to be built over the next few decades, both EPA and EIA project substantial capacity additions for both CTs and CCGTs. Table

[172] This database has since been renamed Air Markets Program Data ("AMPD").
[173] These data (which form the basis for Figure 7) are provided in Sierra Club *et al.*, Joint Environmental Comments (Corrected), EPA-HQ-OAR-2011-0660-10887 (July 9, 2012), Appendix D: *NGCO2 Workbook*, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-10887. We have attached these spreadsheets as **Appendix B- NGCO2 Workbook** to these comments. *See also* **Appendix C- Gas Turbine Workbook New.**

2 below is reproduced from the RIA for the proposed NSPS, and shows EPA's and AEO's references cases for unplanned cumulative capacity additions in the coming years.[174]

Table 2: EPA and AEO Reference Cases for Unplanned Cumulative Capacity Additions (in GW)
Source: EPA, RIA for Proposed GHG NSPS

	EPA	**AEO**		
Capacity Type	**2020**	**2020**	**2025**	**2030**
Conventional Coal	0	0	0	0
Coal with CCS	2	0.3	0.3	0.3
Natural Gas CC [CCGT]	7.0	3.1	17.4	48.2
Natural Gas CT	3.0	15.4	28.0	43.3
Nuclear	0	0	0	0
Renewables[16]	26.9	3.7	6.4	10.5
Distributed Generation	0	0.9	1.9	3.1
Total	**38.9**	**23.4**	**54.1**	**105.4**

EPA has provided no rationale for excluding peaking units from its proposed regulation. However, it is clear that the proposed exemption cannot be based on an assertion of excess costs. A review of the pricing data in the 2013 GTW Handbook[175] reveals that there is no demonstrable correlation between the efficiency of a CT within a given size class and its capital cost.

[174] RIA, Table 5-1.
[175] *See* Gas Turbine World, *supra* n. 131.

Fig. 7: Efficiency vs. Cost- Smaller CTs
Source: 2013 GTW Handbook[176]

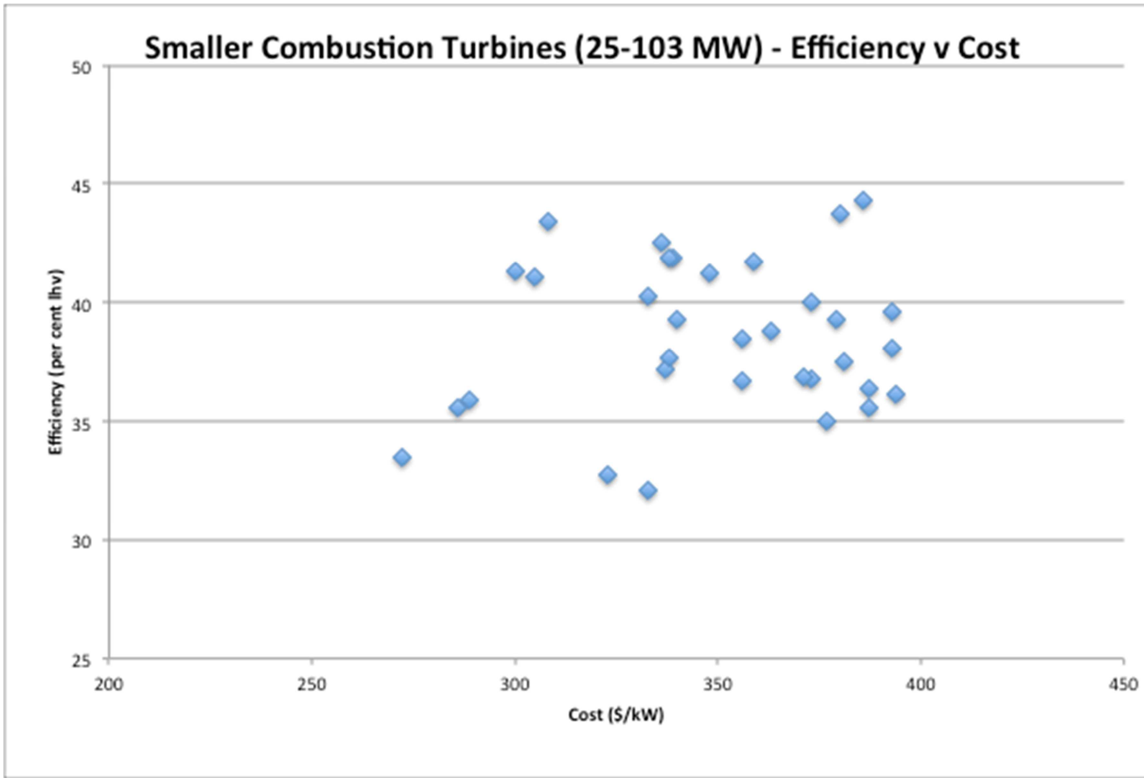
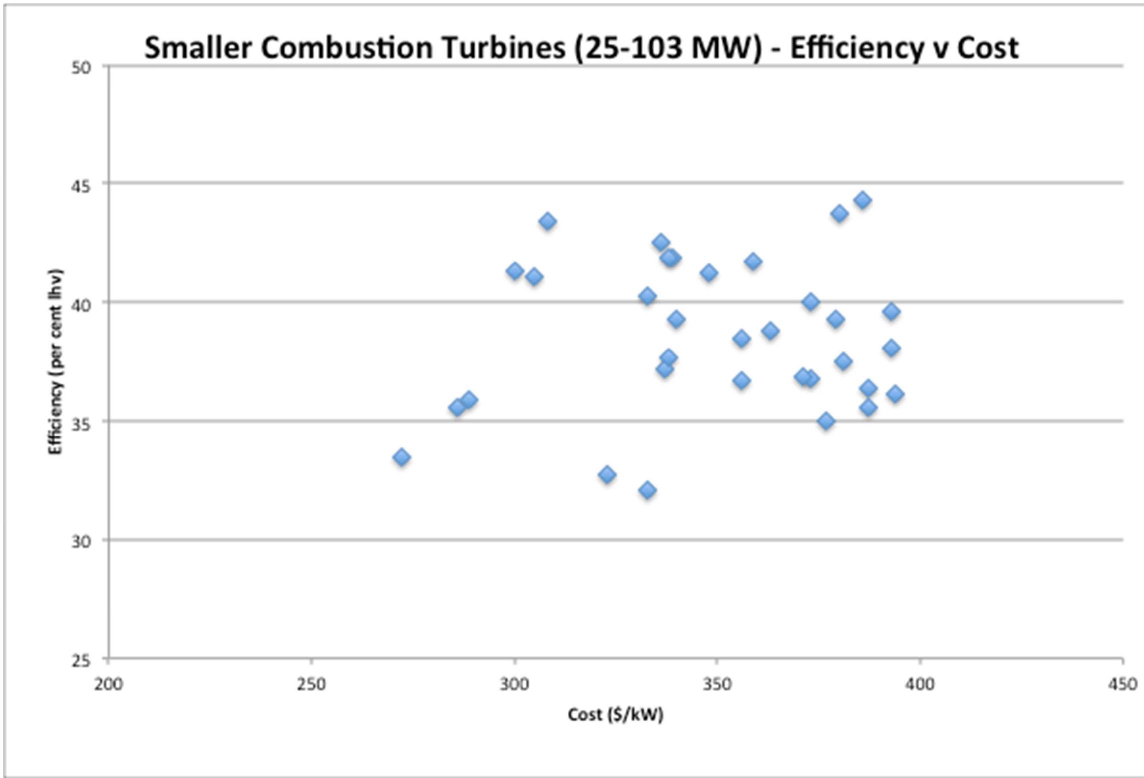


Figure 7 above, which charts smaller CTs, reveals no clear pattern between a unit's efficiency and its cost per kW of generating capacity. However, Figure 8 below shows an unmistakable trend: the price per kW of capacity for larger CT units declines as the size and efficiency of the unit increase. Thus, as a general matter, for larger CTs, less efficient units are costlier. There is no clear pattern within smaller subsets of capacity that could lead to a determination that more efficient CTs cost more than their less efficient counterparts.

[176] Data for Figures 7 and 8 are also included in **Appendix D- CT Cost v Efficiency Analysis**.

Fig. 8: Efficiency vs. Cost- Larger CTs
Source: 2013 GTW Handbook



An examination of paired units of similar sizes reveals that any differences in the initial cost of units of different efficiencies will be small and that in many instances a more efficient unit has a lower initial cost than a less efficient unit. Table 3 below illustrates this quite clearly.

Table 3: Efficiency vs. Cost- CTs Generally
Source: 2013 GTW Handbook

Unit Designation	Capacity (MW)	Efficiency (%)	Price (MM$)	Cost/kW[177] ($)
25 MW Units				
SwiftPac 25	25.5	38.1	10.1	393
UGT 25000	25.7	35.6	9.94	387
MobilePac	26.1	36.1	10.31	395
50 MW Units				
SGT-800	47.5	37.7	16.04	338
LM6000 PF Sprint	48.1	41.9	16.28	339
SGT-900	49.5	32.7	15.97	323
LM6000PC Sprint	51.2	41.9	16.82	333
LM6000PG	51.2	41.8	17.29	338
113 MW Units				
SGT6-2000E	112.0	33.9	31.87	285
M501DA	114.0	34.9	32.5	286
185 MW Units				
7F 3-Series	185.0	38.1	45.74	247
M501F3	185.4	37.0	45.35	245
232 MW Units				
GT 24	230.7	40.0	55.14	239
SGT6-5000F	232.0	38.8	49.42	213

The Trent 60 CT is offered in several configurations with varying efficiency ratings. In Table 4 below, again we see that the differences in price are small and that some configurations with greater efficiency cost less than some less efficient configurations. These units are far more efficient and cost less per kW than the SGT-800 and SGT-900 described above in Table 3.

[177] These prices are described as "estimated equipment-only prices for basic power plant." They do not include transportation of the unit to the site, the cost of land, utilities, engineering and builder's overnight costs that will not increase (but may decrease slightly) if a more efficient unit is chosen. Accordingly, the percent difference in the unit costs shown herein is greater than the percent cost difference to the rate payer.

Table 4: Efficiency v. Cost- The Trent 60 CT Mode
Source: 2013 GTW Handbook

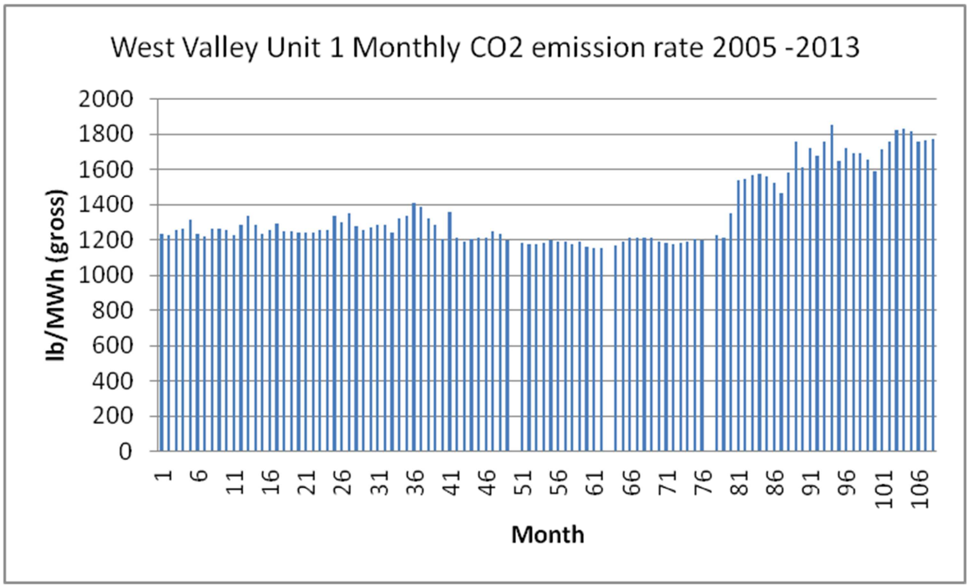
Unit Designation	Capacity (MW)	Efficiency (%)	Cost (MM$)	Cost/kW ($)
Trent 60 DLE	54.0	42.5	18.14	336
Trent 60 DLE ISI	61.8	43.4	19.0	308
Trent 60 WLE	62.9	41.3	18.9	300
Trent 60 WLE ISI	65.6	41.1	20.0	305

The GE LMS 100 PA and PB series CTs are 100 MW units that have a unique intercooler design and are the highest rated efficiency CTs at 44.3 and 43.7 percent, respectively. These designs are priced at $386/380 per kW, approximately 100/kW ($10 million) more than conventional designs. However, these units have proven to be commercially successful with 18 units sold in the United States from January 2011 to December 2013[178] because of their significantly greater fuel efficiency. Since more efficient units will have lower operating costs going forward due to lower fuel use, initial unit cost differences, if any, of the magnitude reported by manufacturers to the Gas Turbine World Handbook will be largely or entirely offset and result in little or no additional cost to ratepayers. Accordingly there can be no basis to suggest that a limit on the emission rate for new CTs would impose excessive costs on the industry.

Indeed, the need for regulations covering peaking units is apparent in EPA's review of CCGTs in its Technical Support Document ("Gas TSD") for this proposed rule. The agency's study of CCGT units between two and twelve years of age shows a number of units with monthly emission patterns that suggest a need for major maintenance or changes in operating practices.[179] Figure 9 below provides an example of the West Valley Unit 1, which is one among a number of instances in EPA's data set showing variable monthly emission patterns. This figure suggests that the West Valley unit should be a target for a major overhaul to regain the more efficient emission profile that it is capable of achieving. It is reasonable to conclude that peaking unit operating and maintenance practices similarly show that monthly variations occur within the operation of a single unit, just as they do for CCGTs. Peaking units should therefore be included in the regulations, with an appropriate limit, to ensure efficient operation.

[178] Gas Turbine World, *supra* n. 131, at Section 4 ("GT Plant Orders and Installations").
[179] EPA Reviewed CO_2 emissions data from 2007 to 2011, which included 307 units. *See* EPA, *Combustion Turbine Standard TSD* (*"Gas TSD"*) and attachments, EPA-HQ-OAR-2013-0495-0082 (Sept. 2013), *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0082, attached as **Ex. 55**; *see also* 79 Fed. Reg. at 1486.

Fig. 9: Average Monthly Emissions for West Valley Unit 7B
Source: EPA, CAMD/AMPD[180]



Setting a carbon pollution standard for peaking units is not only essential for ensuring high efficiency and low emissions from new simple cycle CTs, but could also help ensure that EPA's forthcoming emission guidelines for existing EGUs comprehensively address carbon pollution from the power sector. Section 111(d) of the Clean Air Act requires that states submit plans that implement standards of performance for any source "to which a standard of performance would apply if such existing source were a new source."[181] Therefore, the exclusion of peaking units from the NSPS for CO_2 pollution from new EGUs could leave uncertainty as to whether such units would be subject to section 111(d) standards. Peaking plants emitted 20 million metric tons of CO_2 in 2012, and it is essential to include these units in the carbon pollution standards for existing power plants both to reduce those emissions and avoid creating perverse incentives for increased emissions from these units. Low cost, common sense opportunities are available to reduce these emissions by improved maintenance and operating practices.

Sensible regulation of existing peaking units under section 111(d) provides an opportunity to obtain meaningful emission reductions at a reasonable cost. Thus, EPA should not exempt *new* peaking units and thereby unnecessarily complicate the opportunity to examine these issues in more detail in the upcoming rulemaking concerning existing units. Joint Environmental Commenters therefore recommend that EPA apply the proposed rule to all

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[180] The data illustrated in this graph are available for download at http://ampd.epa.gov/ampd/. In addition, data for this plant from 2007 through 2011 can be found in EPA's Gas TSD, *supra* n. 179, at Ex. 1 ("New_Source_GHG_NSPS_Combustion_Turbine_Standard_TSD"), included as **Appendix G** to these comments.

[181] This term includes modified sources. *See* 42 U.S.C. § 7411(a)(2).

units, but adjust the emission limit based on different tiers of operating hours. The "peaking" tier limit should be set at 1,100 lb CO_2/MWh (net) for units that operate fewer than 1,200 hours annually. This limit would allow less efficient CT units to continue to serve true peaking needs. The tiered structure would also ensure that load-following needs, which may cycle on and off each day according to recent GHG PSD permits, would be met with more efficient combined-cycle units.

a. EPA's Proposed Applicability Provision Does Not Serve to Distinguish Peaking Units from Intermediate-Load and Baseload Units.

EPA noted that its definition of units operating below a 33 percent capacity factor would not expressly exclude simple cycle units from the rule, but has stated that, as a practical matter, most CTs would be excluded because they do not operate at more than a 33 percent capacity factor.[182] We agree with EPA that most CTs do not generally operate at more than a 33 percent capacity factor; the problem is that most true peaking units (as opposed to intermediate or load-following units) operate at capacity factors far lower than 33 percent, and that many units that are not peakers operate at capacity factors of less than 33 percent. To illustrate this point, it bears mention that only three of 1,743 CTs in EPA's AMPD data set[183] would be classified as regulated EGUs under EPA's proposal. However, approximately one-sixth of existing coal-fired EGUs would also be exempt, Figure 10 below demonstrates.[184]

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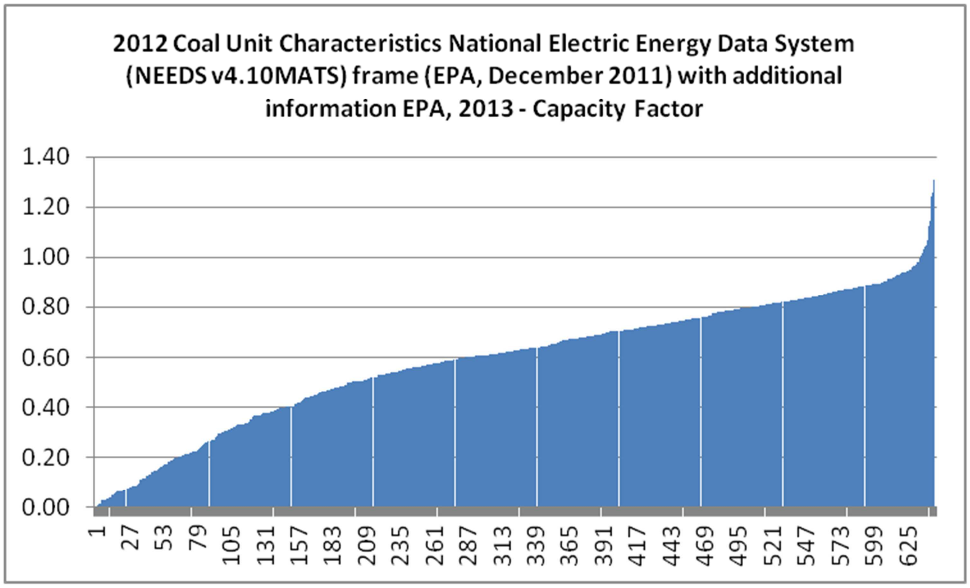
[182] EPA refers to "capacity factor" as an EGU's threshold energy output (MWh) to the grid. *See* 79 Fed. Reg. at 1459. This is an odd use of the term capacity factor, which typically refers to the actual operation of a unit compared to its potential over a given stretch of time. For instance, if a unit operates at 80 percent load for 8,760 hours in a year, it would have an 80 percent capacity factor. Similarly, if a unit operated at full load for 7,008 hours, it would also have an 80 percent capacity factor.

[183] *See* http://ampd.epa.gov/ampd/.

[184] This figure is based on data for a single year. Over a three year average, as EPA proposes, additional units would be exempt.

Fig. 10: Annual Capacity Factors of Existing Coal-Fired EGUs
Source: EPA, National Electric Energy Data System[185]



An even greater percentage of CCGTs would also be exempt from regulation under this proposal. The average capacity factor for CCGTs in 2003 was only 33.4 percent, rising over time to 42 percent in 2009. During the same time period, the average capacity factor for coal-fired units ranged from 60 to 70 percent.[186] Indeed, many of the "new" CCGT units evaluated by EPA in the course of reviewing its proposed limits would be exempt under the current proposal. EPA reports that the average capacity factor for the "new" CCGTs studied by the agency in the TSD for the proposed Subpart KKKK standard was 36 percent; the average capacity factor for "small" units in this study was 27 percent.[187] By way of illustration, we note that EPA's review included TVA Barry Units 7A and 7B that are large (346 and 312 MW) CCGTs. These units operate year round in a load following mode, but have capacity factors in the range of 20 percent.[188] Having commenced operation in 2001, they reported average emission rates during the EPA study period of 801 and 878 lb CO_2/MWh, respectively. There is no reason why similarly operated new units should be exempt from the NSPS and why the Barry Units and similar units should not fall within the scope of EPA's forthcoming emission guidelines under section 111(d). As the Barry Units reflect, the agency's exemption under the current proposal is far too broad and could allow an unnecessarily large portion of the electric sector to avoid NSPS regulations.

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[185] *See* EPA, *National Electric Energy Data System (NEEDS) v.4.10*, *available at* http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#needs.
[186] *See* EIA, *Electric Power Annual 2009* (Apr. 2011), *available at* http://www.eia.gov/electricity/annual/archive/03482009.pdf.
[187] Gas TSD, *supra* n. 179.
[188] *Id.* at Exhibit 1.

EPA's applicability provisions for the proposed rule also raise several concerns with regard to peaking units. As discussed above, the reference to a source's "potential" electric output in the proposed applicability language would create a loophole for fast-start CCGTs, which often function as peakers and allow excessive use of inefficient CTs for intermediate and load-following purposes. Furthermore, the agency has not explained why "one-third of the potential electric output" should differentiate between EGUs and non-EGU units. While this distinction 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. Accordingly, Joint Environmental Commenters proposed above a number of revisions to the proposed applicability provisions that close any potential loopholes while covering all those sources to which the performance standards should rightly apply. *See generally* section *VII.B*.

Whatever EPA's concerns may be with regard to peakers, there is simply no basis for crafting such a broad exemption as the one included in the proposed rule. In the preamble, EPA itself acknowledges that CCGTs operating at 33 percent are still more cost effective than CTs: "According to the AEO 2013 values, advanced combined cycle facilities have a lower cost of electricity than advanced simple cycle turbine facilities above a *20 percent capacity factor*." 79 Fed. Reg. at 1459 (emphasis added). Under the factors relevant to a BSER determination—feasibility, costs, the degree of emission reductions achievable, and technology—advanced combined cycle outperforms simple cycle in every category. If EPA applied the rule to all CTs and CCGTs, regardless of capacity factor, a proper determination of BSER would ensure that more efficient CCGT technology is required for intermediate and load-following units.

We note that peaking units and even intermediate-load units are built for 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 CCGT units may operate for relatively few days per year, such that their electric output falls below the proposed 33 percent threshold. Furthermore, as demonstrated above, 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. This is not just a theoretical concern: EPA has issued several permits recently for facilities that intend to install multiple simple-cycle units to operate up to 5,000 hours per year.[189] These are not peaking facilities that may turn on for a few weeks during the hottest and most energy-

[189] *See* EPA, Region IX, *Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center* (Nov. 2012) [SD-11-01] [permitted for 4,337 hours], *available at* http://www.epa.gov/region9/air/permit/otaymesa/EPA-R09-OAR-2011-0978-response-to-comments-ppec-11-2012.pdf, attached as **Ex. 56**; EPA, Region IV, *Responses to Public Comments on the Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station*, PSD-EPA-R4013 (Jan. 2014)] [permitted for 5,000 hours], *available at* http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC_011314.pdf, attached as **Ex. 57**; EPA, Region VI, *PSD Permit for GHG Emissions- Montana Power Station* (Mar. 25, 2014) [PSD-TX-1290-GHG] [permit for 5,000 hours], *available at* http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/el-paso-electric-final-permit.pdf, attached as **Ex. 58**.

intensive part of the summer. Rather, these simple-cycle facilities are designed to operate daily for load-following purposes.

Joint Environmental Commenters therefore strongly urge EPA to change its EGU definition to eliminate this significant loophole. By limiting regulated sources to cover 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 the standard. We believe the problem may be remedied if the definition is clarified such that all EGUs that provide energy capacity to the grid are subject to the rule.

5. Inclusion of Integrated Equipment

Current regulations define steam generating unit as "any furnace, boiler or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included.)" 40 C.F.R. § 60.41a. A combined cycle gas turbine is defined as "a stationary turbine combustion system where heat from the turbine exhaust gasses is recovered by a steam generating unit." *Id.* EPA's proposal amends these definitions by adding that an "affected facility" includes the generating unit, as defined above, "plus any integrated equipment that provides electricity or useful thermal output to either the boiler or to power auxiliary equipment.'' 79 Fed. Reg. at 1498, 1506, 1510.

In the preamble, EPA provides two reasons for the proposed revision. First, it asserts that "integrated equipment may be a type of combustion unit that emits GHGs, and . . . it is important to assure that those GHG emissions are included as part of the overall GHG emissions from the affected source." *Id.* at 1460. As such, the revision "avoids circumvention of the requirements by having a boiler not subject to the standard supplying useful energy input (e.g., an industrial boiler supplying steam for amine regeneration in a CCS system) without accounting for the GHG emissions when determining compliance with the NSPs." *Id.* Second, the revision "recogniz[es] the environmental benefit of integrated equipment that lowers the overall emissions rate of the affected facility," since it encourages plant operators to incorporate renewable technology into the hardware design of their facilities and thereby improve the thermal efficiency of the fossil-burning generators. *Id.* For example, a number of combined cycle gas plants around the world,[190] including the Palmdale Hybrid Power Plant[191]

[190] *See* RenewableEnergyWorld.Com, *Moroccan CCGT Solar Hybrid Initiated* (Jan. 20, 2010), *available at* http://www.renewableenergyworld.com/rea/news/article/2010/01/moroccan-ccgt-hybrid-initiated, attached as **Ex. 59**; Business Green, *GE touts hybrid gas, solar and wind power plant as answer to energy crisis (*Nov. 22, 2011), *available at* http://www.environmental-expert.com/news/ge-touts-hybrid-gas-solar-and-wind-power-plant-as-answer-to-energy-crisis-268585, attached as **Ex. 60**; Siemens, *Integrated Solar Combined Cycle (ISCC)*, *available at* http://www.energy.siemens.com/hq/en/fossil-power-generation/power-plants/csp-power-block/, attached as **Ex. 61**; GE, *Combined cycle power plant for*

and the FPL Martin Next Generation Solar Energy Center,[192] both in the United States, already use concentrated solar power ("CSP") thermal units either to preheat the feedwater for their steam cycles or to generate steam. As a result, these plants require less thermal input from their combustion turbines and operate with improved overall efficiency.

Under the current proposal, all of the components of this kind of plant—the combustion turbine, the heat recovery steam generators, and the solar thermal unit—would, together, qualify as the "affected facility." This is because each of these components is an integral part of a single system; where each component is a necessary or constituent component of the overall system, it is substantially different from a system in which disparate systems are merely "integrated," such as a CCGT operating alongside a wind farm. Joint Environmental Commenters agree with EPA and strongly support provisions that encourage design innovations that reduce GHG emissions from new power generation subject to the NSPS. The CSP-augmented CCGTs discussed above are examples of concepts that should be facilitated by the NSPS. A CSP facility supplying steam to an ICGG CCS unit would also appear to be of significant value in terms of emission reductions. Furthermore, we agree that it is important to account for all GHGs associated with production of electricity at a regulated unit.

We note that the proposed revision to the existing definition is not needed to encourage CSP-augmented gas- or coal-fired generation. Permits for the units described above were obtained in routine fashion under current regulations, and no regulatory barrier to the continued implementation of this technology appears to exist. Electric utility steam generating units, including HRSGs, have always included components such as reheaters and economizers to recover and use waste heat. The reduced GHG emissions achieved by these components are properly accounted for in the current procedures for determining the facility's GHG emissions rate. There is nothing in the regulation that currently prohibits or discourages an operator from using solar thermal, waste heat recovery, or any other non-emitting technique—such as better insulation—to enhance the unit's efficiency and reduce emissions. Furthermore, the record shows that there is no need to relax standards to accommodate these units. Existing CSP/CCGT hybrids can readily meet the emissions levels proposed by EPA, as well as those recommended herein.[193] Such units should be evaluated by EPA as a potential BSER and certainly as a BACT candidate in appropriate settings. However, the proposal to incorporate any heat supplied (as opposed to electricity) serves to encourage the use of renewable technology for this purpose

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solar and gas, *available at* http://www.ge.com/europe/downloads/Combined_cycle_power_plant_for_solar_and_gas.pdf, attached as **Ex. 62**.

[191] *See* City of Palmdale, *Palmdale Power Plant*, *available at* http://www.cityofpalmdale.org/departments/publicworks/power_plant/, attached as **Ex. 63**.

[192] *See* FPL, *FPL's Martin Next Generation Solar Energy Center- World's First Hybrid Solar Energy Center*, *available at* http://www.fpl.com/environment/solar/pdf/Martin.pdf, attached as **Ex. 64**.

[193] For instance, the Palmdale Hybrid Power Plant's permit under the PSD program establishes a CO_2 emissions limit of 774 lbs/MWH on a net basis. *See* EPA, Region IX, *PSD Permit for Palmdale Hybrid Power Plant*, SE-09-01 (Oct. 18, 2011), at 8, *available at* http://www.epa.gov/region9/air/permit/palmdale/palmdale-final-permit-10-2011.pdf, attached as **Ex. 65**.

and, does no harm that we can discern, and serves an additional useful function of ensuring that the CO_2 emissions associated with the additional steam are included in the calculation of the net emission rate of a regulated unit.

In addition to technology that produces useful thermal output, EPA's proposed modification would include in the definition of "affected facility" any "integrated" equipment that produces electricity. Here, the risk of potential abuse appears to outweigh any potential benefits that might be achieved. We are concerned that electric power supplied by a separate generation source with lower emissions and used to meet the auxiliary power needs of a coal-fired CCS plant would fit within this definition and thereby improve the plant's calculated net output emission rate without reducing emissions from the unit and without ensuring that new EGUs are built to be as low-emitting as possible, utilizing available, cutting-edge, low-emitting technologies, as these standards are intended to require.

A 600 MW coal-fired power plant could readily meet the emission limits proposed by EPA if it were "integrated" with sufficiently large renewable generation capacity. However, Joint Environmental Commenters are aware of no renewable electric generating equipment that could be considered an integral part of a fossil fuel-fired EGU's design. For example, General Electric has designed and constructed what it calls an integrated CSP/CCGT/wind plant in Turkey.[194] The various elements at this novel plant are integrated in the sense that a single operator can control the outputs from all generators from the same location and in real-time. However, from an engineering or emissions perspective, while the CSP solar unit is an integral part of the heat management system, there is no direct relationship between the CCGTs and the wind farm, which could easily be located 100 miles away and still be controlled from the same location as the CCGT.

On the other hand, the CSP unit and the CCGTs at the General Electric plant are components of a single system—that is, the CSP has no function other than to provide thermal output to the CCGT and is of no use without the CCGT. By contrast, placing solar PV panels on the roof of a boiler house, or providing switching mechanisms from a nearby wind farm or hydropower plant, would not improve the performance of a regulated fossil-fired unit and should not be permitted as a compliance mechanism for such generators.

We agree that in the next few years a variety of innovative projects may be proposed to produce electricity with fewer CO_2 emissions, including the projects discussed above. Where such projects achieve verifiable improvements in the efficiency of the fossil fuel-fired EGU itself, EPA should consider a revision to the definition of "affected facility" that appropriately recognizes those emission reductions. However, we also anticipate that EPA's proposed

[194] *See* Press Release, GE, *MetCap Energy Selects GE's New FlexEfficiency Technology for World's First Integrated Renewables Combined Cycle Power Plant* (June 7, 2011), *available at* http://www.genewscenter.com/Press-Releases/MetCap-Energy-Selects-GE-s-New-FlexEfficiency-Technology-for-World-s-First-Integrated-Renewables-Combined-Cycle-Power-Plant-3125.aspx, attached as **Ex. 66**.

amendments to the definition that term may encourage some operators to circumvent the final performance standards without achieving real reductions in emissions.[195] EPA should consider a revision to the definition of "affected facility" that distinguishes between *integral* and *integrated* systems. However, there is a significant risk that the agency will not be able to anticipate the full range of circumstances that may arise in determining how to account for CO_2 in unique or novel applications. To address this, EPA should provide a discussion in the preamble to the final regulation that provides guidance as to how it will apply the circumvention provisions of 40 C.F.R. § 60.12.[196] The provisions in the relevant appendices to the rule should require a source that wishes to construct a configuration not expressly discussed in the rule or preamble to seek an applicability determination or alternate compliance demonstration approval for such systems. Potential scenarios for discussion and clarification include the following:

(1) A boiler has two sets of burners—one for gas, one for pulverized coal. This is normal and accepted co-firing. The CEMS measures all CO_2 generated by the boilers and the operator measures the net generation at the point where the electricity leaves the plant.

(2) A coal-fired boiler accepts steam from a separate boiler, which is then directed to either the main turbine or to a separate turbine to provide electricity for the plant's auxiliaries. This boiler may be a new gas boiler subject to subpart Da, or it may be an existing boiler that is not subject to the new source limit and is likely not subject to a specific existing source limit under section 111. Here, the correct outcome is reached if all of the CO_2 emissions that result from the generation of steam are counted against the emission limit of the regulated unit, regardless of whether the separate boiler is considered "integrated" or "integral."

(3) A coal-fired boiler sends all of its output offsite, while using electricity produced by unregulated fossil-fuel fired units (either onsite or offsite) to power the auxiliaries needed for the carbon capture system. This activity should be considered circumvention, since the arrangement serves no function other than to circumvent the applicable limit. EPA's proposed "integration" provision would not fully address this situation, since the lower-emitting unregulated unit used in this manner would effectively be allowed to "average" its emission rate with the higher-emitting regulated unit, even though the only purpose for the arrangement is to circumvent the rules.

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[195] For example, a new fossil fuel-fired EGU could simply co-locate with an existing wind farm or CSP facility and attempt to claim that those pre-existing renewable generation facilities are "integrated" with the new EGU, even though the wind farm's operation would have no effect on emissions from the EGU.

[196] "No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere." 40 C.F.R. § 60.12

> There may be several possible ways to address this issue, including a provision in the appropriate appendix to the rules specifying that, in calculating a unit's net, the owner/operator shall assume that all electricity used by essential auxiliaries is from the regulated unit.

EPA has also requested comments on whether it should amend the definition of "affected facility" to include not only integrated equipment, but any non-integrated, non-emitting electricity generation equipment that is co-located with the primary plant. *See* 79 Fed. Reg. at 1498. Joint Environmental Commenters strongly urge EPA not to adopt provisions that would permit operators to credit electricity generated by equipment that is simply co-located with a new power plant. The proposed re-definition would allow operators to construct solar panels or wind turbines alongside a newly constructed fossil-fired plant and credit any electricity generated by those units when calculating the emissions rating of the facility, even though (as explained above) the renewable generators would not actually offset any emissions from the fossil-fired units. The more electricity generated by its non-emitting equipment, the more an operator could artificially discount the carbon emissions produced by its fossil-fired generators. This loophole would effectively eviscerate the rule.

As discussed in section III, *supra*, the legislative history of § 111(b) makes clear that Congress's intent is for these standards to ensure that new sources are built using cutting-edge technology to minimize emissions of harmful air pollutants. The definition of affected facility should ensure that new source designs that would reduce emissions of CO_2 pollution are encompassed within the design but eliminate any loopholes that would allow for sources using old, high-emitting technologies to be built simply because they are co-located with a renewable energy source or are in some way linked to a renewable energy source that does not actually reduce emissions from the fossil fuel-fired plant or improve its generating efficiency.

We note that EPA did not consider technologies that are not part of the fossil-fuel fired generating unit in determining BSER for the affected facilities. We have identified the CSP technology discussed above as one means to achieve better performance in new EGUs and recommended that EPA factor this technology in its determination of BSER. To the extent that EPA expands the compliance options available to a source, it must take those options into account in establishing the emission limits that reflect BSER.

Another potential loophole arises in the context of *integrated* coal gasification combined cycle facilities. Here, the potential for circumvention arises if an operator segregates the coal gasification process from the combustion and electric generation process. EPA's definition of an IGCC is simply a CCGT that is designed to burn fuels containing 50 percent (by heat input)[197] or more solid-derived fuel not meeting the definition of natural gas. As this definition is now formulated, the location of the gasifier is irrelevant. However, some may infer the notion of integration into the definition, since it is included in the term itself: *integrated* gasification combined cycle.

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[197] We have explained elsewhere in this comment why a 50 percent threshold is inappropriate.

Moreover, one can contemplate a situation in which the operator of an offsite syngas plant is not in a direct business relationship with the operator of the IGCC/CCGT. EPA should address this potential for abuse by (1) providing that in the process of determining compliance, where a facility combusts more than 10 percent solid-derived gasified fossil fuel, it shall account for the CO_2 emissions associated with the gasification of that fuel in determining whether it has complied with the applicable standard; and (2) including in the "circumvention" rule[198] in subpart 60's General Provision a statement clarifying that where an IGCC/CCGToperator has a direct contract (i.e., a power purchase agreement) for part or all of the output of a coal gasification unit, that unit shall be considered part of the IGCC/CCGT. In addition, since such offsite gasification facilities may also enter into contracts with operators of CTs, EPA should apply similar restrictions on the combustion of gasified fossil fuel derived from solids. Whether a coal gasification plant produces fuel that meets commercial standards for natural gas may have bearing on how NO_x and SO_2 emissions are treated in an NSPS for those pollutants. However, this issue is irrelevant to whether the CO_2 emissions from the conversion processes should be included in determining whether the unit is an IGCC subject to the proposed regulations.

6. Small Unit Emission Rates

EPA proposes separate emission limits for small ($\leq$ 850 MMBtu/h) and large (>850 MMBtu/h) CCGTs. 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 are no physical principles that prevent smaller CCGT units from achieving efficiencies on par with those 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.[199]

As discussed earlier, Congress enacted the NSPS program in part to spur technological innovation. 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. 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 Joint 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 emission limit for units that fall below 850 MMBtu/h heat input threshold, rather than relax the standard for the more common and more efficient larger units that 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 1,000 lb CO_2/MWh (net) is warranted for these smaller units.

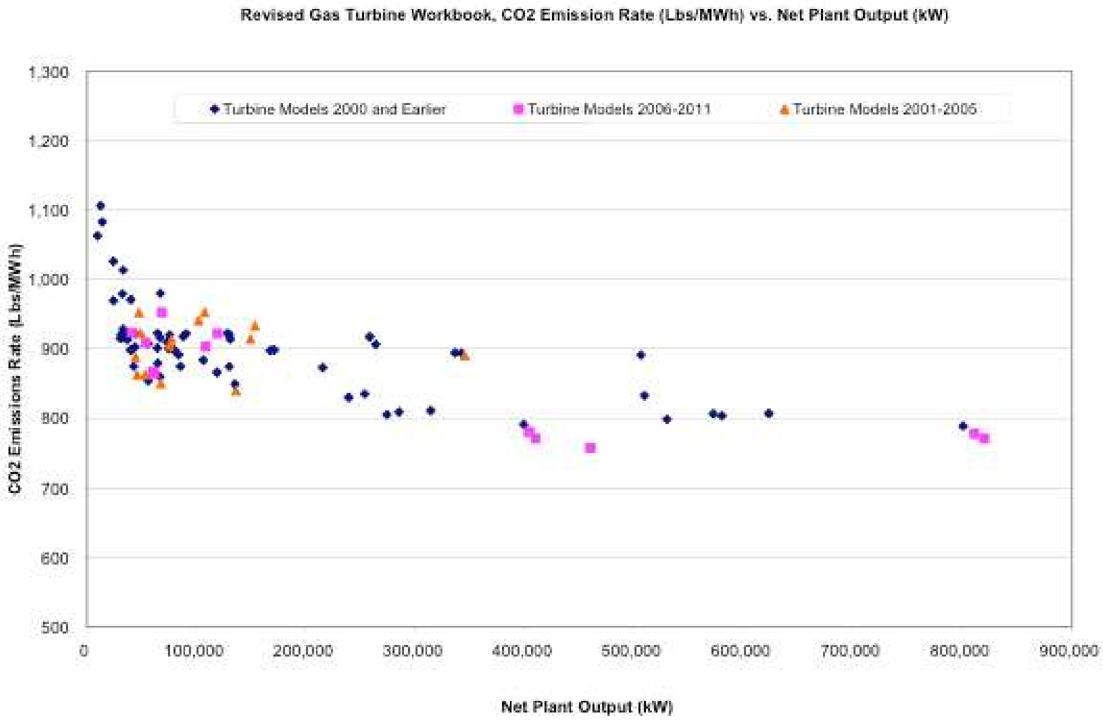
[198] See 40 C.F.R. § 60.12.
[199] *See* Gas Turbine World, *supra* n. 131.

The Gas Turbine World unit performance specifications depicted in Figure 11 below show a substantial number of potential small combined cycle designs where the demonstrated emission rate at ISO conditions is at or below 900 lb CO_2/MWh.[200] With the application of reasonable factors to account for operation at non-ISO conditions, an emission limitation of 1000 lbs CO_2/MWh (net) appears to be attainable by these units. If EPA determines that different subcategories according to size are warranted, it should clarify that multiple small units built together should be treated as a large unit if the combined output of the facility exceeds 850 MMBtu/h. We note that several recently permitted facilities included a series of 100 MW units built together.[201] Facilities should not be permitted to meet less stringent emission limits merely by building a series of smaller units rather than a single larger unit.

[200] *See* Sierra Club *et al.*, Joint Environmental Comments, EPA-HQ-OAR-2011-0660-10798 (June 25, 2012), Ex. C- Gas Turbine Spreadsheet Revised, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-10798, included as **Appendix B** to these comments. These data derive from Gas Turbine World handbook. We note that the aforementioned web address provides access to the original comments and exhibits that a number of the Joint Environmental Commenters submitted in regard to EPA's 2012 NSPS proposal. These organizations later submitted corrected commits and additional exhibits, which are available under the docket no. OAR-2011-0660-10887 and at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-10887. The corrected comments are attached herein as **Ex. 67**. While some exhibits to that submission are included in docket no. EPA-HQ-OAR-2011-0660-10798, and may be accessed at the corresponding web address, several others are available in docket no. EPA-HQ-OAR-2011-0660-10887, and are available at that docket's web address.

[201] EPA, Region IX, *PSD Permit for Pio Pico Energy Center- Proposed Revised Permit Conditions*, SD-11-01 (Nov. 2013) [three 100 MW CTs], *available at* http://www.epa.gov/region9/air/permit/otaymesa/2013-11-pio-pico-proposed-rev-psd-permit.pdf, attached as **Ex. 68**; EPA, Region VI, P*SD Permit for GHG Emissions- Montana Power Station*, *supra* n. 189 [four 100 MW CTs]; attached as **Ex. 69**.

Fig. 11: CO_2 Emission Rate (lb/MWh) vs. Net Plant Output- Small CCGTs
Source: Gas Turbine World 2011 Specifications[202]



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Taken together with our recommendation to establish three tiers of emission limits for large units based on operating hours, the "small unit" subcategory would entail a fourth type of BSER applicable to natural gas units. These four subcategories appropriately distinguish between the different types and functions of varying turbine designs while ensuring that each category achieves the optimal degree of emissions reductions.

X. Biomass and Bioenergy

The Proposed NSPS is intended to limit the amount of CO_2 emitted by steam-generating electric utility boilers and stationary combustion turbines that burn fossil fuels. EPA's proposal to apply the standard to EGUs that derive at least 10 percent of their heat input from fossil fuels on a three-year rolling average basis is therefore appropriate. *See* 79 Fed. Reg. at 1446/2. First, this proposed applicability threshold is consistent with the approach taken in the MATS rule, which also covers EGUs that derive more than 10 percent of their average annual heat input from coal and oil. *See* 77 Fed. Reg. 9304, 9309/2 (Feb. 16, 2012). Second, if a nominally "biomass-fired" EGU derives more than 10 percent of its heat input from fossil fuels, it does so voluntarily (*i.e.*, safe operation of the facility does not require the additional use of fossil fuel), and should be regulated accordingly. Facilities that mainly burn biomass typically burn a relatively small amount of fossil fuel for the purpose of flame stabilization; as explained

[202] The data for Figure 11 are included in **Appendix E**.

in the MATS rule, however, EPA believes that its 10 percent threshold "accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to [the final MATS rule for coal- and oil-fired EGUs]." *Id.* Consequently, EGUs that use fossil fuel for more than 10 percent of their heat input (*e.g.*, in response to fuel costs or other factors) should be regulated as fossil fuel-burning stationary sources. Third, EGUs that co-fire biomass and fossil fuels can be significant sources of fossil fuel CO_2, even if they derive as little as 11 percent of their heat input from fossil fuels. If EPA were to utilize an applicability threshold higher than 10 percent, a significant amount of CO_2 emissions from fossil fuel-fired electricity generation would go unregulated.

VIII. BSER for Coal-Fired EGUs

A. Carbon Capture and Sequestration is the Best System of Emission Reduction for New Fossil Fuel-Fired Boilers and IGCCs.

EPA's proposal to set an emissions limit for utility boilers and IGCC units based on partial implementation of as BSER is well-justified. *See* 79 Fed. Reg. 1430, 1467-77. As we explain below, CCS provides significant emissions reductions and co-benefits, CCS systems are available for fossil fuel boilers and IGCCs and the technologies have been utilized in industrial applications for decades, and the costs are reasonable and can be accommodated by industry.

As discussed in detail in section III, standards of performance must be forward-looking and technology-forcing, reflecting "the degree of emission limitation achievable through the application of the best system of emission reduction ["BSER"] 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." 42 U.S.C. § 7411(a)(1). The term "adequately demonstrated" requires a showing by EPA "that there will be 'available technology'" during the regulated future." *See Portland Cement I*, 486 F.2d at 391 (D.C. Cir. 1973). The standard does not require that a "best system of emission reduction" be in actual commercial use on all or even many facilities in the regulated industry at the time the standards are initially set. *See, e.g., Essex Chem. Corp.*, 486 F.2d 427 (finding that the CAA does not require that a sulfuric acid plant be currently in operation which can at all times and under all circumstances meet the standards).

Congress intended section 111 standards to drive technology transfer between sectors. *See, e.g., Lignite Energy Council*, 198 F.3d at 933-34 (upholding EPA decision to base the NSPS for utility boilers on a control technology that, at the time, had limited performance data because the technology had been applied in the U.S. only to a similar industrial category). EPA may "extrapolat[e]…a technology's performance in other industries," *id.*, and "EPA's choice [of BSER] will be sustained unless the environmental or economic costs of using the technology are exorbitant." *Id.* at 933.

1. CCS Technologies Are Well-Demonstrated and Available for Fossil Fuel-Fired Boilers and IGCC EGUs.

CCS technologies have been used in various industrial applications for decades, and many projects are under construction or planned in the power generation sector. Below, Joint Environmental Commenters describe some of these projects that provide support for EPA's proposal. While we agree with EPA that any new coal plant must employ partial CCS at the very least for control of CO_2 emissions, we do not intend our comments to serve as an endorsement of any particular coal project or to support the continued use of coal in any capacity as a source of electricity generation.

a. The Technologies Used for CO_2 Capture and Sequestration at Coal-Fired and IGCC EGUs have been Demonstrated at Commercial Scale in Other Applications for Decades.

CO_2 separation and capture technologies have been in use in gas processing and other industrial applications for decades. EPA provides many examples in the proposed rule and accompanying materials. 79 Fed. Reg. at 1474-75. The following list offers a few examples of these projects:

<u>Pre-combustion:</u>

- The Great Plains Synfuel plant in North Dakota is a coal gasification facility that has been producing synthetic natural gas since 1984. Since 2000, the facility has been separating 7,700 tpd of CO_2 that is injected for EOR.[203]
- The Century gas processing plant, located in Pecos County, Texas, began operations in 2010. The plant currently has a capture capacity of 5 Mtpa of CO_2, which is used in EOR.[204]
- The Coffeyville Gasification Plant in Kansas converts petroleum coke into synthetic gas that is used to produce ammonia and fertilizers. The project began operating in 2013 and plans to capture and sequester the CO_2 are underway. [205]

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[203] Pacific Northeast Nat'l Laboratory, *An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009* (June 2009), at 6-7, *available at* http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18520.pdf, attached as **Ex. 70**; Global CCS Inst., *Great Plains Synfuel Plant and Weyburn-Midale Project* (project data current as of Feb. 16, 2014), *available at* http://www.globalccsinstitute.com/project/great-plains-synfuel-plant-and-weyburn-midale-project, attached as **Ex. 71**; Dakota Gasification Co., *About Us*, *available at* http://www.dakotagas.com/About_Us/, attached as **Ex. 72**.

[204] Global CCS Inst., *Century Plant* (project data current as of Feb. 16, 2014), *available at* http://www.globalccsinstitute.com/project/century-plant, attached as **Ex. 73**; Oxy, *Facilities Construction*, *available at* http://www.oxy.com/OurBusinesses/OilAndGas/Technology/FieldDev/Pages/FacilitiesConstruction.aspx, attached as **Ex. 74.**

- Petrobras Lula Oil Field CCS Project in Brazil is a natural gas processing plant that began operations in 2013. The plant captures 700,000 tpa of CO_2, which is injected for EOR below the ocean floor.[206]

Post-Combustion:

- Since 1976, the Searles Valley Minerals plant in Trona, California has recovered 270,000 tpy of CO_2 from a coal-fired power plant for carbonation of brine in producing soda ash.[207]
- Mitsubishi's CO_2 recovery process has been used at some natural gas facilities in India since 2006, recovering up to 450 metric tons per day of CO_2.[208]

Sequestration:

EPA has cited to numerous CO_2 commercial storage projects as well as field studies that demonstrate the feasibility of geologic sequestration. *See* 79 Fed. Reg. at 1472-74. For example, since 1996 the Sleipner natural gas processing project in the North Sea has separated CO_2 from natural gas and sequestered .9 Mtpa of CO_2 in an offshore deep saline reservoir.[209] Gravity and seismic monitoring have verified that the CO_2 is behaving as expected and no leaks have been detected.[210] Additionally, the oil and natural gas industry in the United States and abroad has five decades of experience in injecting captured CO_2 into geologic formations.

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[205] Global CCS Inst., *Coffeyville Gasification Plant* (project data current as of Feb. 16, 2014), *available at* http://www.globalccsinstitute.com/project/coffeyville-gasification-plant, attached as **Ex. 75**.

[206] Global CCS Inst., *Petrobras Lula Oil Field CCS Project* (project data current as of Feb. 16, 2014), *available at* http://www.globalccsinstitute.com/project/petrobras-lula-oil-field-ccs-project, attached as **Ex. 76**.

[207] EPRI, *CO_2 Capture and Storage Newsletter*, Issue 2, at 1 (Dec. 2006), *available at* http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001014698, attached as **Ex. 77**; ZEROCO$_2$.NO, *Searles Valley Minerals*, *available at* http://www.zeroco2.no/projects/searles-valley-minerals, attached as **Ex. 78**; Pacific Northeast National Laboratory, *supra* n. 203, at 9.

[208] Mitsubishi, *Commercial Experience in India: Aonla*, *available at* http://www.mhi-global.com/products/expand/km-cdr_experiences_03.html, attached as **Ex. 79**; Mitsubishi, *Commercial Experience in India: Phulpur*, *available at* http://www.mhi-global.com/products/expand/km-cdr_experiences_04.html, attached as **Ex. 80**.

[209] Pacific Northeast Nat'l Lab., *supra* n. 203, at 5-6; Global CCS Inst., *Sleipner CO_2 Injection* (project data current as of Feb. 16, 2014), *available at* http://www.globalccsinstitute.com/project/sleipner%C2%A0co2-injection, attached as **Ex. 81**.

[210] "*Report of the Interagency Task Force on Carbon Capture and Storage* (Aug. 2010), at C-4-5, *available at* http://energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf, attached as **Ex. 82**; Pacific Northeast Nat'l Laboratory, *supra* n. 203, at 5-6.

Department of Energy ("DOE") studies indicate that the U.S. has ample CO_2 storage potential. *Id.* at 1473.

We support EPA's conclusion that geologic sequestration of CO_2 is available and adequately demonstrated for the purpose of establishing CCS as BSER for coal-fired EGUs. And we agree with EPA that site characterization of each potential storage site is essential to ensure safe and permanent storage. *Id*. at 1473. We also describe further in section VII.C below that EPA must fix three provisions of the proposed rule to ensure that captured CO_2 is permanently sequestered underground.

b. CCS Technologies For Coal-Fired EGUS Are Available.

NSPS standards must be forward-looking and technology-forcing. The "best system of emission reduction" need not be in actual commercial use in the regulated industry at the time the standards are initially set. *See, e.g., Portland Cement Ass'n*, 486 F.2d at 391; *Essex Chem. Corp.*, 486 F.2d 427.

EPA has provided many examples of commercial scale capture projects in power generation that are under construction and proposed for regulatory approval. *See* 74 Fed. Reg. at 1474-75. There are many additional examples of commercial scale projects, including the following:[211]

- The Boundary Dam project in Saskatchewan, Canada will add post-combustion capture to a 110 MW lignite-fueled power plant. The plant is designed to capture 90 percent of the CO_2 from the 110 MW unit or approximately 1 Mtpa, which will be transported for EOR at Weyburn as well as for sequestration in a deep saline formation.[212]
- The Rotterdam Opslag en Afvang Demonstratieproject (ROAD) project in the Netherlands will include a 250 MW post-combustion capture unit that is planned to capture approximately 1.1 Mtpa of CO_2 for storage in offshore, depleted oil and gas reserves.[213] Operation of the integrated CCS chain is planned for 2015.

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[211] *See also* Global CCS Inst., *The Global Status of CCS: 2013, Appendix A: Projects*, *available at* http://www.globalccsinstitute.com/publications/global-status-ccs-2013/online/118006, attached as **Ex. 83**.

[212] SaskPower, *Boundary Dam CCS Project*, *available at* http://www.saskpowerccsconsortium.com/ccs-projects/saskpower-initiatives/carbon-capture-project/, attached as **Ex. 84**; SaskPower, *Boundary Dam Integrated Carbon Capture and Storage Demonstration Project* (April 2012), *available at* http://www.saskpower.com/wp-content/uploads/clean_coal_information_sheet.pdf, attached as **Ex. 85**.

[213] Global CCS Inst., *Rotterdam Opslag en Afvang Demonstratieproject (ROAD)* (project data current as of Feb. 16, 2014), *available at* http://www.globalccsinstitute.com/project/rotterdam-opslag-en-afvang-demonstratieproject-road, attached as **Ex. 86**; Rotterdam Climate Initiative, *ROAD*, *available at* http://www.rotterdamclimateinitiative.nl/nl/co2-afvang,-transport-en-opslag/projecten/road?portfolio_id=167, attached as **Ex. 87**.

B. The Costs of Implementing Partial CCS Are Reasonable; they Are Far from Exorbitant and Can Be Absorbed by the Electric Generation Industry.

The costs of EPA's proposed standard will be upheld as long as they are not "exorbitant." *Lignite Energy Council*, 198 F.3d at 933 (costs are considered acceptable as long as they can be accommodated by the industry). Section 111 allows EPA to take a broad view of the costs of the proposed standard at the national and regional level, which includes consideration of the pollution benefits that would be achieved, the avoided costs of carbon pollution on society as well as the co-benefits of reducing harmful $PM_{2.5}$ and ozone pollution. *See Sierra Club*, 657 F.2d at 330. From an industry-wide perspective, the incremental costs of partial CCS on few new coal-fired plants spread over a region would be inconsequential. For these reasons, the costs of EPA's partial CCS standard easily meet the standard under Section 111.

1. Proposed Partial CCS Standard Would Significantly Reduce Pollution

As discussed in section III, *supra*, although EPA is not required to engage in a traditional cost-benefit analysis, the degree of the pollution reduction benefits that a proposed standard would achieve must be considered along with the costs of achieving it. *See Sierra Club*, 657 F.2d at 314, 327-28 (upholding costly SO_2 standards that would provide significant pollution benefits); *Essex Chem. Corp.*, 486 F.2d at 437 (acid mist standards were reasoned and cost-benefit analysis was not required).

EPA's proposed partial CCS standard would achieve significant reductions in CO_2 emissions that are urgently needed in the power sector. EPA's proposed standard would reduce CO_2 emissions in SCPC plants by 33 percent (600 lb CO_2/MWh net) and in IGCC plants by 18 percent (300 lb CO_2/MWh net). *See* RIA at 5-35, Table 5-10.[214] The partial CCS standard will also result in additional co-benefits of reducing NO_x, SO_2, and $PM_{2.5}$. RIA at 5-39; *see infra* section VII.B.4. In order to help ensure that the pollution reductions are permanent, EPA must augment its current regulatory scheme governing sequestration. As such, Joint Environmental Commenters propose three revisions to the proposed rules, as discussed below in Section VII.C.

2. Incremental Costs of CCS On a Few New Coal Plants Can be Accommodated by Industry

EPA properly determined that the costs of partial CCS can be accommodated by industry. EPA's conclusion is supported by the broadly-maintained prediction that, due to current and predicted economic conditions, very few new coal-fired power plants will be built in the future, if any. The costs of the partial CCS standard—approximately a 20 percent increase—on a few new coal-fired plants can easily be accommodated by industry. When setting a NSPS, "EPA has authority to weigh cost, energy, and environmental impacts *in the broadest sense at the national and regional levels* and over time as opposed to simply at the

[214] SCPC (1,800) – SCPC +CCS (1,200) = 600 lbs/MWh. 600/1,800 = 33 percent. IGCC (1,700) – IGCC+CCS (1,400) = 300 lb/MWh. 300/1,700 = 18 percent.

plant level in the immediate present." *Sierra Club*, 657 F.2d at 330 (D.C. Cir. 1981). For the same reason, and the additional pollution reduction benefits, Joint Environmental Commenters believe industry can easily accommodate the costs of full CCS.

Referencing a range of authorities, EPA predicts that the vast majority of new power generation sources that will be built in the foreseeable future will be renewable and natural gas facilities, and that very few new coal plants are likely to be built. 79 Fed. Reg. 1477-78.[215] These conclusions are based on many factors including existing excess capacity and low forecasts of electricity demand growth, low prices and regulatory drivers for renewables, low natural gas prices, and increasingly higher costs for coal.[216] EPA modeling showed that through 2022, even in the absence of the proposed rule, other generation technologies would be chosen instead of coal plants.[217]

Because not many new coal plants are likely to be built regardless of the proposed rule, partial CCS will not cause significant industry-wide costs. According to EPA's analysis, and without considering the potential for offsetting costs through sale of captured CO_2 for EOR, the partial CCS requirement for new coal plants would add approximately an additional 12 to 20 percent to the per-MWh cost of electricity for those plants. 79 Fed. Reg. 1476-78 & Table 6.[218] A 12 to 20 percent increase in the cost of electricity at a handful of plants is easily within the capacity of the industry as a whole to absorb. *See Sierra Club*, 657 F.at 330. As such, these impacts will not amount to "exorbitant" costs, and are fully in keeping with the requirements of Section 111. *See Lignite Energy Council*, 198 F.3d at 933. Additionally, the limited additional costs of partial CCS will have little (if any) impact on consumer electric prices at the regional or national levels. 79 Fed. Reg. 1480-81.[219]

We therefore disagree with EPA's conclusion that the costs of full CCS are too high for BSER purposes at this time. We believe that, given that so few new plants, if any, will be built, and given the availability of the components of CCS controls, from an industry-wide perspective, the costs of meeting a standard based on full CCS are not exorbitant.

3. EPA Can Consider Offset of Costs Through EOR Sales, but Costs of Partial CCS Satisfy the Section 111 Standard Without Considering EOR Sales.

While Joint Environmental Commenters do not intend their comments to endorse the practice of EOR, section 111 allows a broad consideration of costs, including the sale of byproducts, and EPA may properly take the possibility of EOR sales into account when

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[215] *See also* RIA at 5-7; 5-29—5-31.
[216] *Id.*, Chapter 5.
[217] *Id.* at 5-1.
[218] *See also id.* at 5-28-34. ($110/MWh for SCPC with partial CCS) – ($92/MWh for SCPC plant without CCSS) / 92 = 20 percent. ($109/MWh for IGCC with partial CCS – $97/MWh for SCPC plant without CCSS) / 97 = 12 percent.
[219] *See also id.* at 5-3.

evaluating the costs of the proposed performance standard. *See Sierra Club v. Costle*, 657 F.2d at 330. ("[S]ection 111 . . . gives EPA authority when determining the best technological system to weigh cost, energy, and environmental impacts in the broadest sense…over time."). Many proposed new power generation projects with CCS plan to sell captured CO_2 to enhanced oil recovery operations.[220] (70% of the CCS projects under construction or at an advanced stage of planning intend to use captured CO_2 to improve recovery of oil in mature fields). EPA properly took into account that "revenues from selling the by-products would defray the costs of pollution control." 79 Fed. Reg. at 1464-5.[221] Joint Environmental Commenters note that ensuring permanent sequestration of CO_2 injected for EOR is essential to realize the rule's objectives, as EOR operations have not historically been designed for this purpose. *See* section VII.C, *infra.*

4. The Agency Properly Considers the Social Costs of Carbon and the Economic and Health Benefits of Associated Conventional Air Pollution Reductions.

EPA properly considered the costs of partial CCS in light of the benefits that will accrue from considering the social cost of carbon and the co-benefits from reduced emissions of other harmful pollutants, including SO_2, NO_x, and $PM_{2.5}$. While Section 111 does not require strict cost-benefit balancing, it allows EPA to consider costs broadly, including consideration of the pollution reductions described above, as well as the social cost of carbon and co-benefits. These considerations provide further support for the conclusion that a partial CCS standard will not impose exorbitant cost, in satisfaction of section 111's standards.

As discussed in section IV above, the IWG on the social cost of carbon has developed a series of values to represent the cost that each metric ton of CO_2 emissions will impose on society into the future. 78 Fed. Reg. 70,586 (Nov. 26, 2013). These values, known as the social cost of carbon, are intended to address considerations such "as changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change."[222] The social cost of carbon can be used to assess the avoided damages that accompany CO_2 reductions, and therefore allow a more accurate determination of the costs of a partial CCS standard.[223] The social costs of carbon escalate over time, but by way of example, the four estimates for 2020 are $13, $46, $69, and $138 per metric ton (2011$).[224] The cost of a partial CCS standard, or, indeed, a full CCS standard, pales when considering a broad view of costs that accounts for the social costs of carbon, as required under Section 111. Furthermore, as several of them have noted in submissions to OMB, Joint Environmental Commenters maintain that the social cost of carbon is in fact much higher than the values in the interagency rule.[225]

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[220] *Id.* at 5-29.
[221] *See also id.* at 5-29—5-31.
[222] *Id.*at 5-36.
[223] *Id.*
[224] *Id.* at Table 5-11.
[225] *See* Sierra Club, *supra* n. 137; EDF *et al.*, *supra* n. 137.

EPA also appropriately considered the co-benefits of reduced emissions of SO_2 and NO_x that would result from the proposed rule's CO_2 emission limits.[226] SO_2 is a precursor to $PM_{2.5}$, and NO_X is a $PM_{2.5}$ and ozone precursor.[227] The harmful impacts on human health from exposure to these pollutants cannot be overstated; they include "premature mortality for adults and infants, cardiovascular morbidity such as heart attacks and hospital admissions, and respiratory morbidity such as asthma attacks, bronchitis, hospital and emergency room visits, work loss days, restricted activity days, and respiratory symptoms."[228] EPA quantified the benefits of reducing these dangerous pollutants with the proposed rule and concluded that reducing one thousand tons of annual SO_2 could result in $PM_{2.5}$-related health benefits between $38 and 85 million in 2020 (2011$). Reducing one thousand tons of annual NO_X from EGUs could produce $PM_{2.5}$-related health benefits ranging between $5.5 and $12 million in the same timeframe. RIA at 5-41. EPA considers these co-benefits and reports in the its RIA that the incremental benefits associated with generation from a new coal-fired unit with CCS relative to a new coal unit without CCS are $2.0 to $45 per MWh (2011$).[229]

C. EPA Must Establish Enforceable Requirements for Sequestration.

Though EPA's proposal intends to ensure captured CO_2 emissions are permanently stored over the long-term, the rule does not contain sufficient enforceable requirements for permanent sequestration. For example, if the geologic storage facility reports high leakage rates, the rule does not require any action on the part of the EGU that was the source of the carbon in question. As EPA implements the requirements of this rule, we strongly urge the agency to work with the appropriate state and federal authorities to establish a comprehensive regulatory structure governing sequestration of captured CO_2. In addition, as we explain below, the text of three of the proposed rule's provisions must be fixed to effectuate EPA's intent that facilities using partial CCS report under Subpart RR of the Greenhouse Gas Reporting Rule.

First, "to provide certainty and verify that CO_2 captured at an affected unit is geologically sequestered," the preamble recites EPA's intent that new units using partial CCS must report under Subpart RR of the Greenhouse Gas Reporting Rule, which governs reporting for facilities injecting CO_2 for long-term sequestration. 79 Fed. Reg. 1483; *see also* 40 C.F.R. § 98.4400 *et seq.* (Subpart RR). The text of the proposed reporting requirement, however, does not reflect this requirement. The proposal currently covers units using "geologic sequestration," which would not encompass EGUs capturing CO_2 for use in enhanced oil recovery.

The term "geologic sequestration" is not defined in the proposed rule; however, it is defined in the Safe Drinking Water Act ("SDWA") as "the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations." 40 C.F.R.

[226] *Id.* at 5-39—5-46.
[227] *Id.*
[228] *Id.* at 3-39; *see also* EPA, MATS RIA, *supra* n. 142.
[229] RIA at Table 5-14.

§ 144.3. Injection of CO_2 for permanent geologic sequestration is regulated under a separate framework (Class VI) than injection of CO_2 for enhanced oil and gas recovery (Class II). *Id.* § 146.5. Thus, the current proposal would not require units that use captured CO_2 for enhanced oil or gas recovery operations to report under Subpart RR of the GHG Reporting Rule as EPA intended.

The requirement to report under the GHG Reporting Rule is essential to account for the fate of the injected CO_2 and to ensure permanent sequestration; subpart RR requires sequestration facilities to implement a monitoring, measurement and verification plan and report the amounts of CO_2 received, injected, produced, emitted by surface leakage and sequestered in subsurface geologic formations. 40 C.F.R. § 98.4400 *et seq*. Indeed, without this reporting requirement, the rule's objective to reduce CO_2 emissions cannot be verified.

The text of the reporting requirement at section 60.46Da(h)(5) must be changed to clarify that units using captured CO_2 for enhanced oil recovery must report under Subpart RR. We suggest amending proposed 60 C.F.R. § 60.46Da(h)(5) as follows:

> If your affected unit captures CO_2 to meet the applicable emissions limit, your affected unit must use either (i) onsite or offsite geologic sequestration, pursuant to a permit issued under Class VI of the Safe Drinking Water Underground Injection Program, and that reports in accordance with the requirements of 40 C.F.R. Part 98, subpart RR, or (ii) send the captured CO_2 for use in enhanced recovery of oil or natural gas, through injection permitted under Class II of the Safe Drinking Water Act Underground Injection Program for that purpose and that reports in accordance with the requirements of 40 C.F.R. Part 98, subpart RR.

Second, the rule must impose additional enforceable requirements to ensure that the affected facility in fact transfers the CO_2 to a facility that is compliant with Subpart RR. EPA should require affected units to provide documentation showing that the volume of captured CO_2 necessary to meet the standard has been transferred to a facility that is reporting under Subpart RR. That requirement should be added to the proposed reporting and record-keeping requirements at 40 C.F.R. § 6060.46Da(h) &(i). Additionally, this reporting should be a condition of the Title V permit for the facility. 42 U.S.C. § 7661c(a).

Third, the subpart PP reporting requirements must be amended to reflect EPA's intent that captured CO_2 will be permanently sequestered as follows:

> § 98.426 Data reporting requirements.

* * * *

> (h) If you capture a CO_2 stream from an electricity generating unit that is subject to subpart D of this part you must *transfer the captured CO_2 to a facility or facilities subject to subpart RR of this part,* and you must:
> (1) Report the facility identification number associated with the annual GHG report for the subpart D facility,
> (2) Report each facility identification number associated with the annual GHG reports for each facility to which CO_2 is transferred, and
> (3) Report the annual quantity of CO_2 in metric tons that is transferred to each facility.

In short, EPA must adopt these suggested revisions to the proposed rule in order to help ensure that sequestered carbon remains underground.

D. ERCC's Claims Regarding the NCA's Position on CCS Are Without Merit

In public comments dated May 9, 2014, the Electric Reliability Coordinating Council ("ERCC") argues that the recently issued final report for the Third National Climate Assessment ("NCA")[230] represents an assessment of the readiness of CCS technologies that contradicts EPA's BSER determination. This claim is wholly without merit.

The NCA is a report that summarizes and synthesizes information on the impacts of climate change on the United States, now and in the future. The NCA does not purport to be an assessment of CCS or any other technology and it contains no analysis or citations to current literature that does assess the current state of technical development and deployment of CCS systems and system components. The NCA does not review a current or complete list of projects and experience with CCS systems, nor examine the experience with component technologies, nor discuss the list of commercial vendors offering fully guaranteed products and services in the areas of CO_2 capture, transport and geologic storage.

The sentences from the NCA cited by ERCC are comments made in passing in a chapter discussing the impacts of climate on energy production systems. Their apparent purpose is to provide a brief description of CCS and not to present conclusions as to the adequacy of its demonstration for consideration under the Clean Air Act. In contrast to the NCA's discussion of its core topic (impacts of climate change), the passage is not supported by citations to current assessments of CCS readiness, and does not provide a comprehensive overview of the projects under construction. As EPA's BSER assessment and the comments submitted herein document, the record establishes that the extensive industrial-scale experience with CCS systems and CCS system components fully support EPA's determination that partial CCS is BSER for fossil fuel-fired steam electric generating units.

[230] *See* USGCRP, *supra* n. 5.

IX. BSER for Gas-Fired EGUs

In determining BSER for natural-gas fired EGUs, EPA considered two alternatives: (1) modern, efficient CCGT; and (2) modern, efficient CCGT with CCS. *See* 79 Fed. Reg. at 1436. The agency determined that modern, efficient CCGT without CCS is BSER, and proposed performance standards of 1,000 lb CO_2/MWh for the large turbine subcategory (applicable to units with a heat input above 850 MMBtu/hr) and 1,100 lb CO_2/MWh for the small turbine subcategory (applicable to units with a heat input equal to or less than 850 MMBtu/hr). *Id.* at 1446—47. As part of the rulemaking process, the agency has solicited comments on standards ranging from 950 to 1,100 lb CO_2/MWh for a large turbines and 1,000 to 1,200 lb CO_2 /MWh for small turbines. *Id*.

Joint Environmental Commenters believe that BSER for natural gas power plants that operate more than 1,200 hours per year should be based on efficient CCGT. However, Joint Environmental Commenters do not agree with the level of EPA's proposed standards, nor with EPA's proposed application of those standards. As discussed above, EPA's proposed standard would essentially exclude all CTs. Therefore, the standards in practice would only apply to CCGT's, and EPA proposed standards that nearly every existing CCGT is currently meeting. Excluding CTs and setting such a weak limit for CCGTs effectively renders the standard meaningless. Joint Environmental Commenters submit that BSER for a subcategory of new sources cannot be set at a level that almost all existing sources currently meet when many of those sources are already achieving much lower emissions levels. EPA's proposed emissions limit for large units does not represent the level of performance that the newest, most efficient CCGT facilities are capable of achieving, and therefore is insufficiently robust to meet the requirements of the statute, particularly the forward-looking, technology-forcing aspects of the BSER determination.

To address these issues, Joint Environmental Commenters recommend that EPA adopt a three-tiered structure for the subpart KKKK facilities. For peaking units (those operating less than 1,200 hours annually), the standard would be 1,100 lb CO_2 /MW; for intermediate/load-following units (those operating between 1,200 and 4,000 hours annually) the standard would be 875 lb CO_2/MWh; and for baseload units (those operating over 4,000 hours annually) the standard would be 825 lb CO_2/MWh.

A. EPA's Proposed Standards for Natural Gas Plants

Section 111(b) of the CAA requires EPA to identify the "best system of emission reduction," or BSER, that has been "adequately demonstrated." 42 U.S.C § 7411(a)(1), (b). As discussed previously, this determination must be forward-looking, not based on what most sources (even most new sources) in the category already are achieving. The BSER assessment encompasses consideration of technical feasibility, costs, the degree of achievable emission reductions, and non-air quality health and environmental and energy factors. *See* 79 Fed. Reg. at 1434. In the proposed rule, EPA determined that CCGT is technically feasible, relatively inexpensive, and, from a carbon dioxide emission standpoint, cleaner than other fossil fuel technologies. *See id.* at 1436. Joint Environmental Commenters agree with this finding, and note in particular EPA's conclusion that "virtually all new sources in this category are using CCGT technology." *Id.* at 1485. However, in setting the performance standard for these units, the agency significantly understated the carbon dioxide emissions performance capabilities of "modern, efficient" CCGT plants, adopting instead an emission limit that is far too lenient in light of the level at which these plants can actually perform. The proposed standard therefore does not reflect the statutory requirement to meet the best degree of emission limitation achievable that has been adequately demonstrated. 42 U.S.C. § 7411(a)(1).

1. The Record Amply Supports a More Robust and Protective Emissions Standard than EPA has Proposed.

As we discuss more fully below, EPA's own data reveal that fully 94 percent of existing CCGT units built since 2000 can meet an emission limit of 1,000 lb CO_2/MWh or lower. This easily achievable standard does not satisfy Section 111's goal of forcing technological innovation, which is one of the cornerstone principles of the NSPS program. As discussed in section III, *supra*, both the legislative history of the CAA and decades of case law confirm that Congress designed Section 111 as a technology-forcing regulatory mechanism aimed at "provid[ing] an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources." S. Rep. No. 9-1196, at 17. *See also*, *e.g.*, *Sierra Club*, 657 F.2d at 364 ("[W]e believe EPA 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 Assoc.*, 486 F.2d at 391 ("Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present."). By establishing a carbon emissions limit for new plants that 94 percent of the CCGT fleet can already satisfy, EPA has failed to look to the "regulated future," but has instead unjustifiably settled on a standard that is squarely rooted in the past, as we will describe more fully below. The proposed limit of 1,000 lb CO_2/MWh does not, therefore, represent the "best" emission rates that are currently achievable by CCGT units, and it will not (by the agency's own reckoning) achieve emissions reductions from new sources that would not have already occurred in the rule's absence.[231]

Electricity generation through natural gas CT and CCGT technology has been common for decades and, indeed, represents the most likely choice for new fossil fuel-fired generation over the next several decades. EPA now proposes to select efficient CCGT as BSER for natural gas-fired stationary combustion turbines that operate at a capacity factor of greater than 33 percent annually. However, EPA's proposed limits do not reflect performance of the newest and most efficient CCGT designs available today or the new technologies—such as fast-response CCGT or concentrated solar power ("CSP")/CCGT hybrids—that are now commercially available. The agency offers no analysis in support of its assertion that the proposed emission

[231] *See* RIA at 5-54 ("These proposed EGU New Source GHG Standard is not anticipated to change GHG emissions for newly constructed electric generating units, and is anticipated to impose negligible costs or monetized benefits.").

limits reflect the performance of "efficient" CCGTs, either in the preamble to the proposed rule or the accompanying TSD for gas plants. To the contrary, the record demonstrates that 96 percent of the plants placed into service from 2000 to 2011currently meet the proposed limits (even though a number of these units are the least efficient designs on the market).[232]

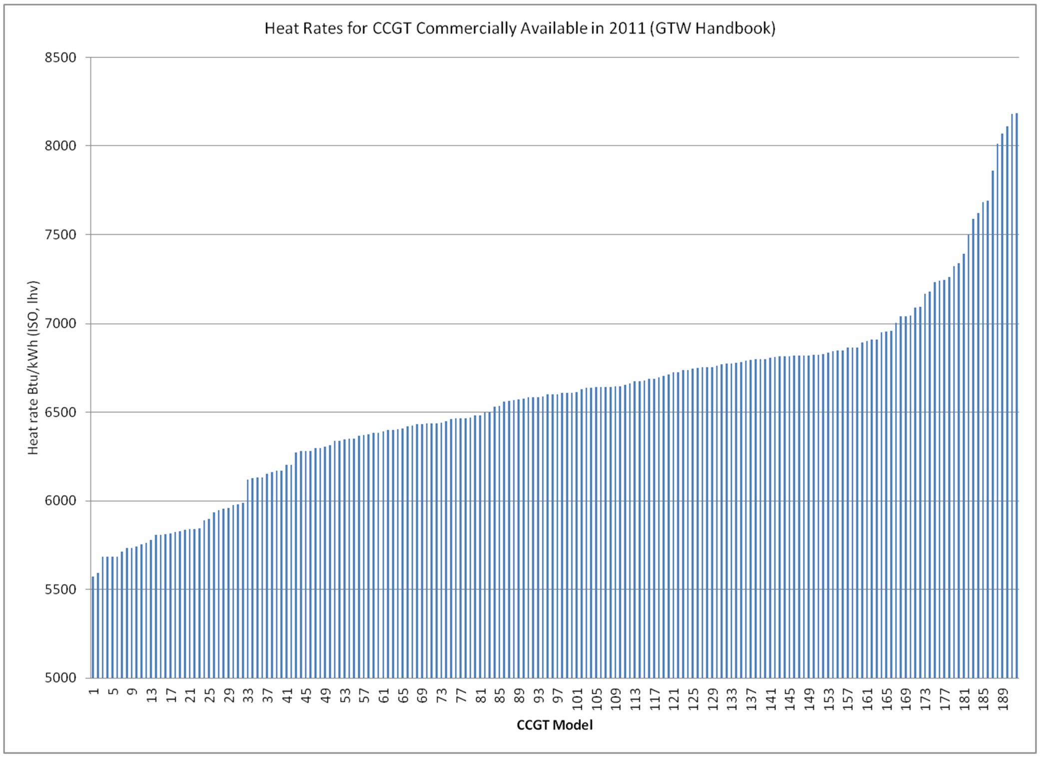
For decades, EPA has made consistent practice of determining BSER under section 111(b) by examining existing sources, as well as technologies that have been either newly developed or used only in other industries. Indeed, EPA has followed that practice in this rulemaking for coal-fired units. Time and again, the D.C. Circuit has approved and endorsed this approach. For instance, in 1974, the agency established NSPS limiting PM emissions from asphalt concrete plants even though some existing facilities were unable to satisfy the new standard. The court upheld the standard over industry objection, reiterating that "'[a]dequately demonstrated' does not mean that existing asphalt concrete plants must be capable of meeting the standard; to the contrary, section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present." *Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 785—86 (internal quotations omitted).

Similarly, in 1981, the agency set NSPS for coal-fired EGUs that required a 90 percent reduction of SO_2 emissions through flue gas desulfurization ("FGD") technology. Industry petitioners objected that this standard relied upon an assumption that had not been demonstrated in fact: that the median rate of SO_2 removal through FGD would be 92 percent. Rejecting this challenge, the court held that EPA had reasonably documented its reasons for concluding that "the standard can be set at a level that is higher than has been actually demonstrated over the long term." *Sierra Club*, 657 F.2d at 361—64. And in 1998, EPA issued NO_x NSPS for industrial boilers that effectively mandated the use of selective catalytic reduction ("SCR"), even though this technology had not previously been deployed for these kinds of boilers. The court again upheld these standards and ruled that, in light of the successful use of SCR in limiting NO_x emissions from utility boilers, the agency had a reasonable basis to extrapolate this technology's feasibility for new industrial boilers in the future. *See Lignite Energy Council*, 198 F.3d at 933—34.

Here, by contrast, EPA has adopted a standard for new gas plants that reflects the performance of the worst performing designs available in the current fleet of CCGT plants. The data EPA relies on reveal that the performance of *existing* CCGT units varies widely in terms of efficiency. Figure 12 below depicts the heat rate for all commercially available CCGT units in 2011. At a minimum, BSER must reflect the level of performance of the best-performing existing designs from this data set, not the worst.

[232] EPA reviewed CO_2 emissions from 2007 to 2011 for all non-CHP CCGT units in operation since January 1, 2000 for which at least two years' worth of data was available. *See* 79 Fed. Reg. at 1486; *see also* Gas Plant TSD, *supra* n. 179.

Fig. 12: Heat Rates for Commercially Available CCGT Units in 2011
Source: 2011 GTW Handbook[233]



Moreover, the differences in efficiencies documented in Figure 12 are the consequence of deliberate decisions by designers to incorporate features and systems that enhance combustion and permit a greater amount of electricity generation per unit of fuel. In other words, there are not inherent limitations in technology that prevent better performance. For example, the performance of a CCGT unit improves when the manufacturer designs the turbine to operate at higher temperatures. For every 30 degree Celsius 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 degrees Celsius.[234] 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 the use of nitrogen instead of steam as the diluent for reducing NO formation. The efficiency of a CCGT unit can be also substantially increased by using fully-fired HRSG units, which have higher (but not unreasonble) construction costs compared to partially fired or unfired HRSGs.[235] These

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[233] These data were employed in EPA's development of the levels proposed in initial rule proposal from April 2012. They are included in **Appendix B**. *See also* **Appendix F- 2011 GTW Heat Rates.**
[234] Chiesa and Macchi, Trans. ASME, 126:4 Journal of Engineering for Gas Turbine and Power 770-85 (Jan. 2004).
[235] *See* Chase and Kehoe, GE Power Systems, *GE Combined-Cycle Product Line and Performance,* at 3, *available at* http://physics.oregonstate.edu/~hetheriw/energy/topics/doc/elec/natgas/cc/combined cycle product line and performance GER3574g.pdf, attached as **Ex. 88**.

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.[236] Elsewhere in these comments we provide cost data showing that these higher efficiency units do not have significantly higher capital costs.

a. EPA Must Set an NSPS That Reflects the Performance of the Newest and Most Efficient CCGT Units.

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 load and part load conditions in both simple and combined cycle modes.[237] Developers have recently introduced new, more efficient models and techniques such as the CSP/CCGT projects,[238] which are not reflected in the performance data EPA used to inform its rulemaking. New high-efficiency products introduced in the past 5 years by major manufacturers such as General Electric, Siemens, Alstom, and Mitsubishi demonstrate the flexibility to support renewable generation, excellent part load performance, and low GHG emissions. These units include the GE ("GE"), Alstom, and Siemens designs specifically designed for daily load following and renewable support applications. Table 5 below provides details on some of the most efficient CCGT models that have emerged on the market in recent years.

[236] *Id.* at Table 14.
[237] *See* Gas Turbine World, 2012 GTW Handbook, at 6-24.
[238] Concentrated solar power ("CSP") technology can and has been retrofitted to existing CCGT units, most notably the Martin Next Generation Solar Energy Center, where 75 MW of CSP capacity was added to an existing 3,750 MW natural gas-fired plant. The approved and permitted (but not yet constructed) Palmdale hybrid project has 570 MW of CCGT capacity and 50 MW of CSP capacity. The PSD permit limit for this unit is 774 lb C02/MWh (net).

Table 5: Recent CCGT Models
Source: 2013 GTW Handbook, manufacturers' websites

CCGT Designation	Turbine Designation	Year	Plant Capacity (MW)	Efficiency (LHV)	Heat rate Btu/kWh
GE Heavy Duty 107 FA	1x7FA.04	2008	277	57.4	5948
GE Heavy Duty 207FA	2x7FA.04	2008	600	57.9	5889
GE Heavy Duty 107 FA	1x7FA.05	2009	320	57.7	6235
GE Heavy Duty 207FA	2x7FA.05	2009	648	58.5	6152
Mitsubishi MPCP1(M501J)	1xM501GAC	2011	404	59.2	5763
Mitsubishi MPCP2(M501J)	2xM501GAC	2011	811	59.4	5744
Mitsubishi MPCP1(M701J)	1xM701J	2011	470	61.5	5549
Mitsubishi MPCP2(M701J)	2xM701J	2011	943	61.7	5531
Siemens SCC-750x1	1xSGT-750	2012	47	51.7	6599
Siemens SCC6-8000H1S	1xSGT6-8000H	2010	410	60.0	5687
Siemens SCC6-8000H 1x2	2xSGT6-8000H	2010	820	60.0	5687

The average heat rate for these new CCGT offerings is 5,734 Btu/MWh (net). This results in a "new and clean" emission rate of 747 lb CO_2/MWh (net), far lower than EPA's proposed limit of 1,000 lb CO_2/MWh (gross) even after assuming a generous compliance margin. The turbines listed above are "modern," available today, and provide a far better indication of CCGT technology that is both technically and economically feasible than does EPA's proposed limit.

b. EPA Does Not Adequately Explain Why a More Robust Standard is Not Selected.

EPA proposes CO_2 emission limits of 1,000 and 1,100 lb CO_2/MWh (gross) for large and small natural gas-fired power plants, respectively (both CT and CCGT units). The TSD examines monthly emission and operating data over the period from 2007 to 2011 for 307 CCGT units located in 33 states. The report does not attempt to define the level of performance that is achievable by the most efficient units, but simply examines whether existing units can meet the proposed standard,[239] and whether cycling, ambient temperature, or elevation affects emission rates.[240]

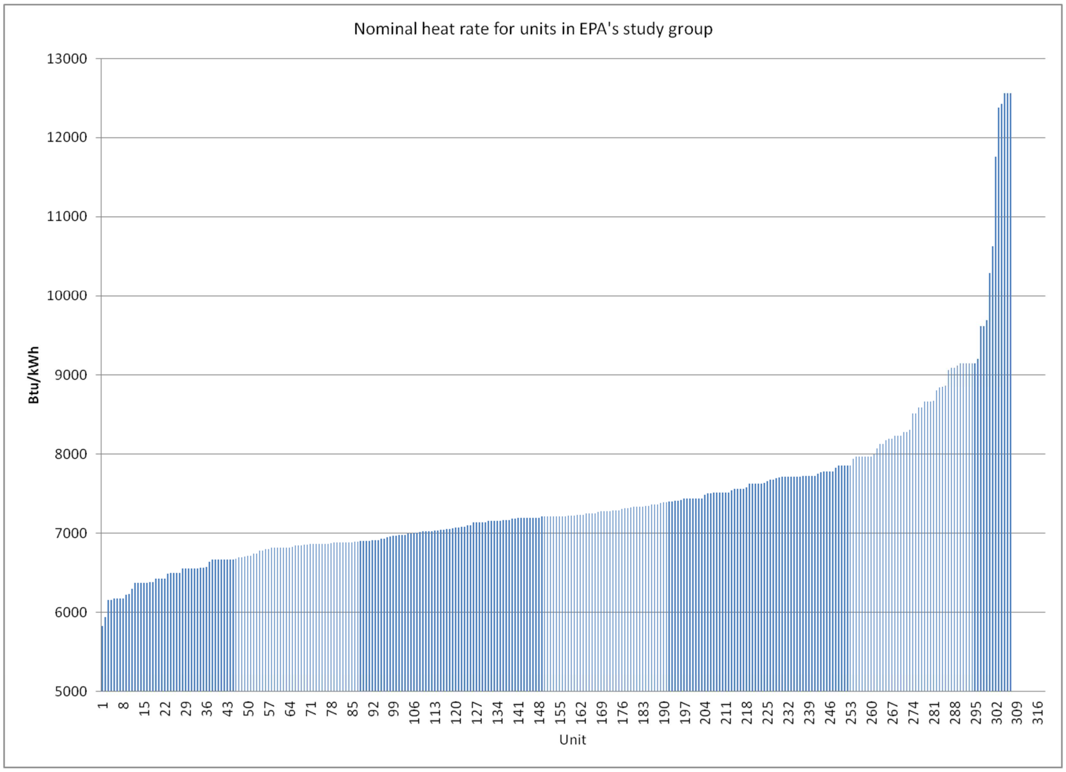
Critically, EPA's TSD acknowledges that the existing units examined in the study group are, on average, less efficient than those currently available in the market.[241] Indeed, 96 percent of all units that have come online between 2000 and 2011 demonstrate consistent compliance below EPA's newly proposed standard. Setting the standard at such a loose level is technology-following, not technology forcing. Clearly, the better-performing CCGT units reviewed in EPA's TSD have adequately demonstrated that lower CO_2 limits are achievable. Notably, those better-performing units achieved lower emission rates even though: (1) the operators of existing sources were not attempting to meet a defined level of CO_2 emissions performance; (2) EPA's study pool included a number of inefficient designs; (3) given permitting, financing, and construction schedules, all plants included in EPA's data pool/study must have been between six and 17 years old; and (4) EPA employed the "average of monthly averages" discussed elsewhere in these comments in deriving the proposed emissions rate from the study data. Figure 13 below depicts the nominal heat rates for plants in the study group.

[239] *See* Gas TSD at 1 ("The purpose of this study is to determine how existing natural gas-fired combined cycle (NGCC) units have performed in comparison to the proposed standards.").

[240] The study found no correlation between unit capacity and the start count—that is, units in the small subcategory had no more or fewer starts than the large units, and neither the number of starts, operating temperature or altitude of the unit affected the unit's ability to meet the proposed standard. The standard did, however, identify a need for a less stringent standard for small units.

[241] *Id.* ("Since this study is retrospective, i.e., measuring the performance of units that are less efficient than currently available on the market, it is inherently conservative.").

Figure 13: Nominal Heat Rates for Units in EPA's Study Group
Source: EPA, Gas TSD[242]

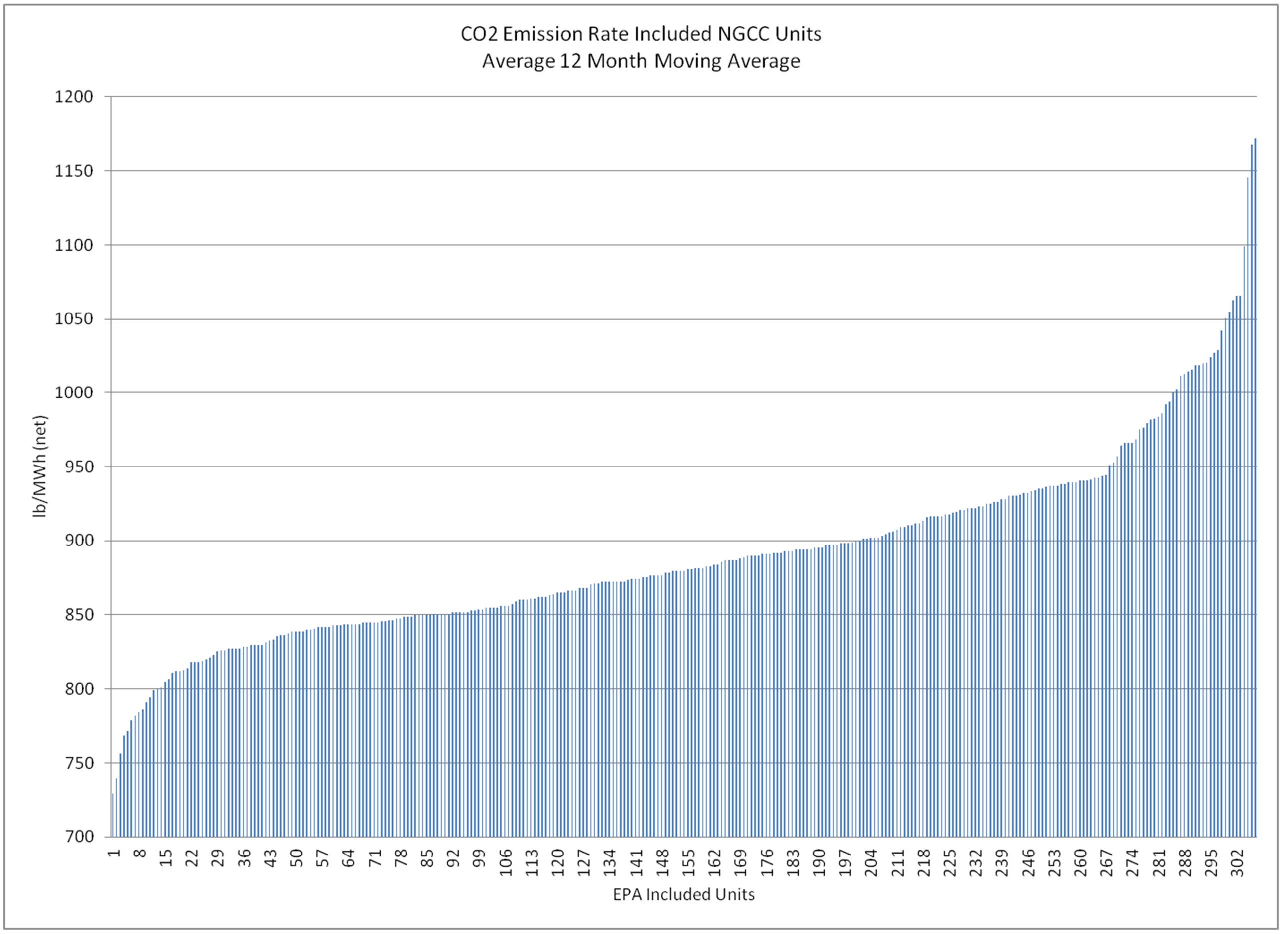


Moreover, EPA's study excluded both units that are currently over 14 years old and new units with less than two years of operating time. As a consequence, the study did not consider 32 units whose nominal heat rate (i.e., the plant's maximum heat input divided by rated generating capacity) is less than 7,000 Btu/kWh.

Figure 14 below depicts the calculated 12-month moving average of CO_2 emissions for each unit included in the study group.

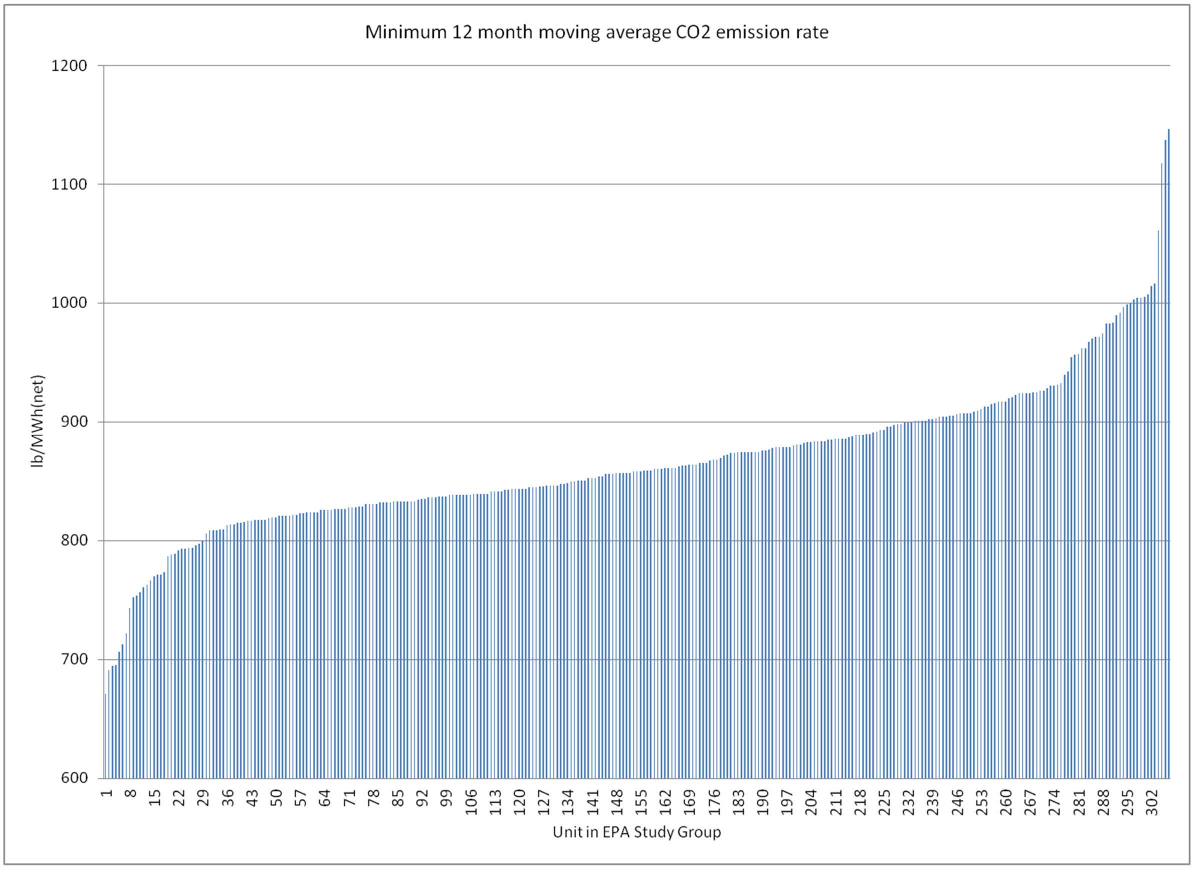
[242] Data for Figures 13 through 16 and Table 6 are also included in **Appendix G- New Source GHG NSPS Combustion Turbine Standard TSD**.

Figure 14: 12-Month Average CO_2 Emission Rates for Units in EPA Study
Source: EPA, Gas TSD



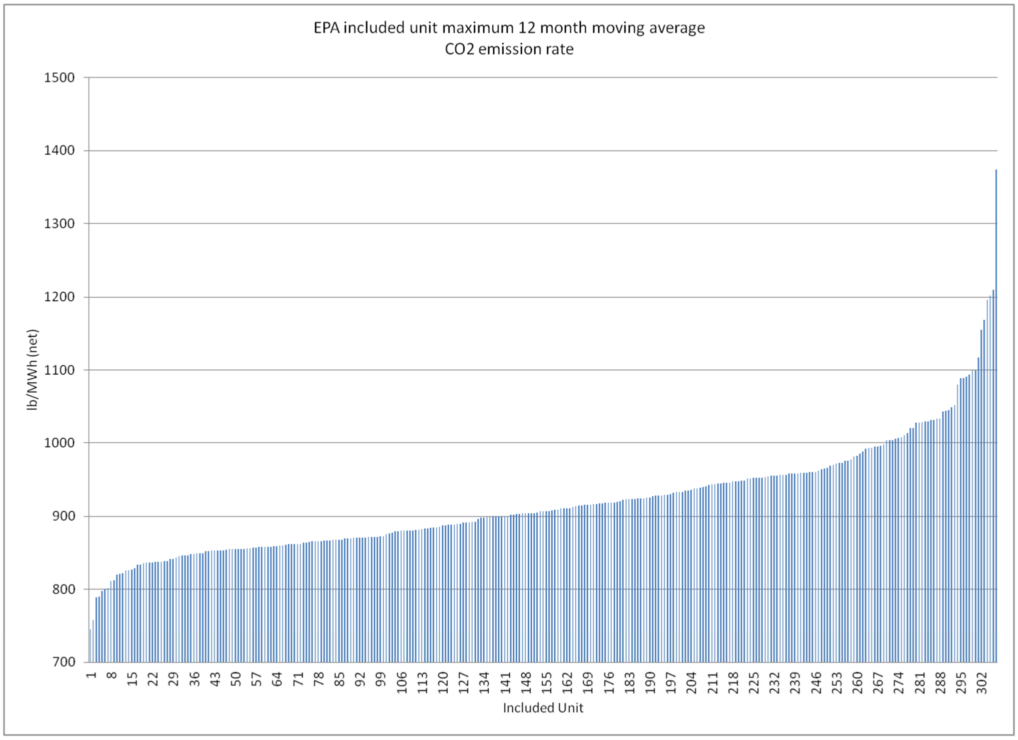
The Gas TSD also reports the lowest 12-month moving average sustained by each unit in the study (*see* Figure 15 below). Note the change in scale in the chart below occasioned by several units that reported emission rates of less than 700 lb/MWh.

Figure 15: 12-Month Minimum CO_2 Emission Rates for Units in EPA Study
Source: EPA, Gas TSD



Even excluding the newest units and considering the relative worst case emissions for a unit that was not attempting to comply with a limit, more than 85 percent of the units currently operating would still meet the 1,000 lb CO_2/MWh (gross) limit proposed by EPA. That is a far cry from a BSER-based emissions rate as required under section 111(b). Figure 16 depicts the 12-month maximum emission rates for units in the study.

Figure 16: 12-Month Maximum CO_2 Emission Rates for Units in EPA Study
Source: EPA, Gas TSD



The relevant statistics for these three conditions are displayed in Table 6 below.

Table 6: Aggregate Data from EPA Study
Source: EPA, Gas TSD

(All figures are lb CO_2/MWh net generation)	Average 12 month moving average	Minimum 12 month moving average	Maximum 12 month moving average
Average Of All Units	890	866	919
Median	880	858	907
Average Of Top 10 Percent	799	762	821
90th Percentile Unit	826	809	846
Average Of Top 20 Percent	817	790	837
80th Percentile Unit	843	824	858
Average Of Top 50 Percent	842	820	863
Average Of Bottom 10 Percent	1033	999	1085
10^{th} Percentile Unit	975	939	1013
Average Of Bottom 20 Percent	990	959	1035
20^{th} Percentile Unit	933	906	960

Section 111 performance standards are not intended to reflect rates that most – or even some—existing sources or units already can achieve. Rather, the standard must reflect the expected performance of the best option, taking into account all the statutory factors, on a forward-looking basis, and based on the recent experience with available new technologies in the industry or similar industries. Thus, the statute does not permit EPA to set a performance standard that reflects the emissions performance of the worst performing units that employ that technology, as it has in the proposed rule. Further, as the term "best system of emission reduction" makes abundantly clear, the standard may not be less than the level of emissions achieved by the *best* technology that may be available and adequately demonstrated for new units (taking into account the relevant considerations under section 111). The standard must account for improvements in performance that may be reasonably anticipated in the time frame over which sources subject to the standard will come online. Just as standards for new vehicles may be more demanding for later model years with more lead time, so too must emissions standards for power plants under section 111(b) require better performance of plants built in later years if supported by reasonable projections of technological improvements during that lead time.[243]

B. Joint Environmental Commenters' Proposed Performance Standards for Gas Plants

EPA correctly concludes that setting a CCGT-based BSER will not impose unreasonable (or even significant) costs upon the industry. See 79 Fed. Reg. at 1486; RIA at 5-54. That is so whether the Agency sets the standard at 825-850 lb/MWh (net) as recommended herein or at the 1,000 lb CO_2/MWh (gross) it proposes. As discussed more fully in section III, *supra*, the D.C. Circuit has held that cost considerations will undermine an NSPS only in highly exceptional circumstances. *See Portland Cement II*, 513 F.2d at 508 (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, EPA's proposed standards for gas-fired EGUs are well within the bounds of section 111's cost standard, described further below. The fact that highly efficient plants are now already being constructed, even in the absence of a CO_2 performance standard, firmly demonstrates that the industry can bear those costs and readily survive, in satisfaction of section 111. *See Portland Cement II*, 513 F.2d at 508. Far from imposing exorbitant costs on industry, these efficient plants save fuel costs per unit of electricity produced, and thus *lower* costs for plant operators.

1. EPA Should Establish Separate Limits for Baseload, Intermediate, and Peaking Natural Gas Plants.

As noted above, EPA's data on emissions from existing gas plants that began operating between 2000 and 2011 show that 96 percent of these units already meet the proposed

[243]Additional data relevant to gas plant performance is included in **Appendices J** through **L**.

standard, even while new flexible CCGT units are now coming online with carbon emission efficiencies substantially better than 1,000 lb CO_2/MWh. Rather than driving the addition of more efficient, better performing, lower CO_2-emitting CCGTs, EPA's proposal actively rewards dirtier and older gas-fired electricity generation technology. This perverse result undermines the purpose of the section 111(b) standard-setting process.

EPA expresses concern that higher-cycling CCGT units may not operate as efficiently as traditional baseload units, and therefore may have difficulty meeting strict CO_2 performance standards (i.e., the 1,000 lbs/MWhr (gross) standard EPA has proposed). EPA can respond to that concern without weakening the standard below a true BSER-based level by setting three class-based subcategories of emission limits based on the annual operating hours of each natural gas unit. EPA has the authority to distinguish among classes, types and sizes of natural gas turbines pursuant to section 111(b)(2).

To develop the subcategory limits below, Joint Environmental Commenters relied on 2012 emission and performance data from EPA's Clean Air Markets Division ("CAMD") for all CCGT and CT natural gas-fired EGUs in the U.S. fleet. Based on our analysis of those data, we recommend that EPA establish the following limits (on a net basis, as discussed in section X, *infra*) for subpart KKKK facilities. The three classes, based on annual operating hours, are as follows:[244]

- Peaking units: < 1200 hours per year = 1,100 lb CO_2/MWh
- Intermediate/load-following units: 1,200—4,000 hours annually = 875 lb CO_2/MWh
- Baseload units: >4,000 hours annually = 825 lb CO_2/MWh[245]

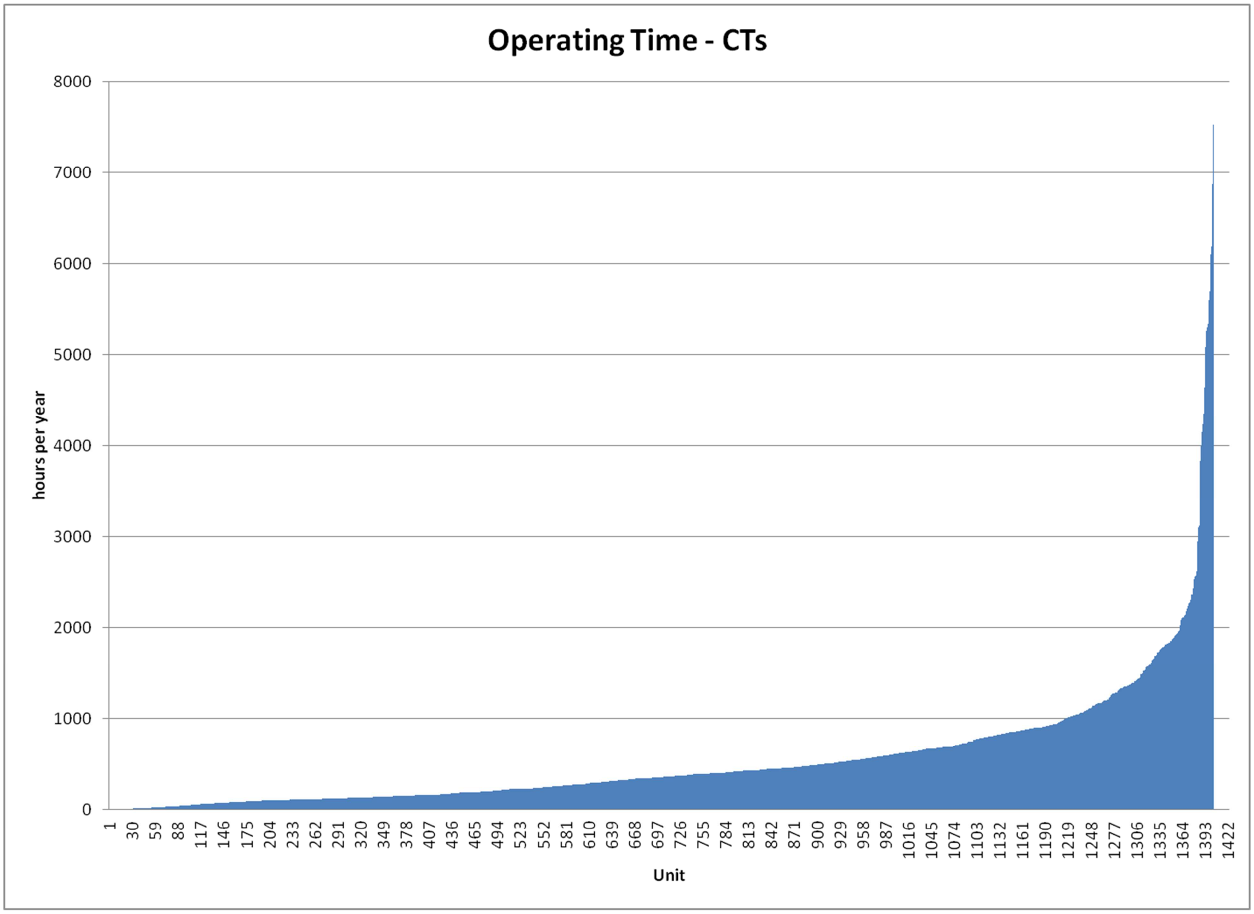
These limits would apply equally to both combined cycle and simple cycle turbines. Practically speaking, however, we expect that baseload and intermediate load functions would and should be met by combined cycle units, while CTs would serve as peaking units. Accordingly, EPA should recognize in its final BSER determinations that a unit operating for more than 1,200 hours per year is no longer serving peaking functions, and should instead be required to meet a standard based on CCGT—which is clearly the best system of emission reduction for units providing intermediate or baseload service. Standards set in this way would satisfy the statutory requirements to base emissions limits on BSER as described below.

a. Peaking Units

[244] In this framework, we do not distinguish small plants (i.e., < 850 MMBtu/hr) from large ones (i.e., > 850 MMBtu/hr). To the extent that EPA believes a separate standard is appropriate for small plants, *see* discussion at section IV.B.
[245] These units would not be subject to any hourly emission limitations.

Data downloaded from CAMD in 2012[246] supports the premise that CTs historically have operated as peaking units with annual operating hours less than 1,200 hours per year. Figure 17 below shows the annual operating hours for CTs included in the data set. Based on current and anticipated natural gas prices CTs are not expected to dispatch at higher rates than in the past in most of the country.

Fig. 17: Annual Operating Hours – CTs
Source: 2012 CAMD Data Set



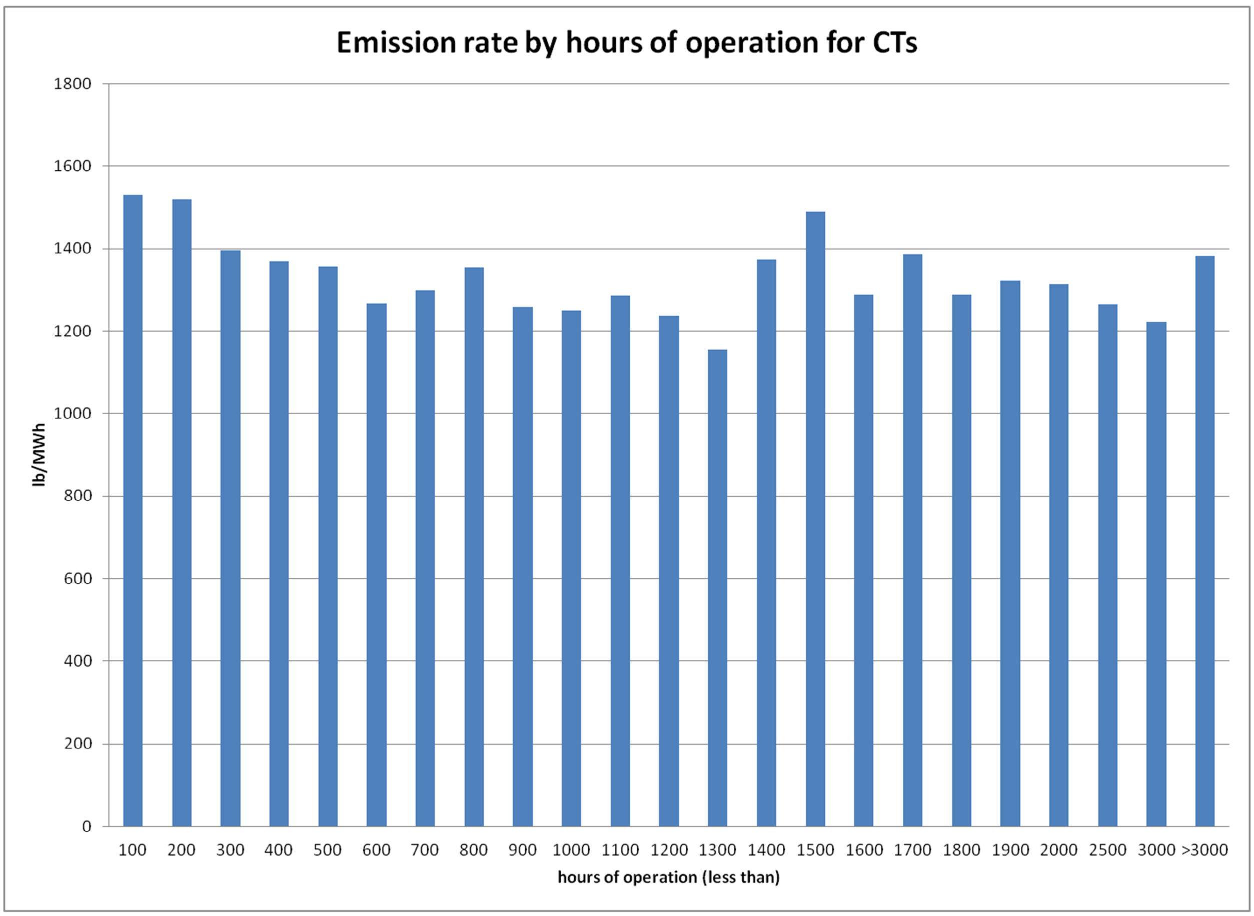
This chart shows that nearly all CTs in the data set operated below 1,200 hours annually. This data is consistent with the common assumption that CTs operate primarily as peaking units. Nothing about CT technology or other characteristics of this industry segment suggests that new CT units would be operated in any different fashion, since their lower efficiencies make

[246] These data, which form the basis for Figures 17 through 20 and Table 7, are currently available for download at http://ampd.epa.gov/ampd/. Additionally, the data for CTs and CCGTs included in **Appendix B,** demonstrate the same trends. *See also* **Appendix H- 2012 Natural Gas Master- 1** and **Appendix I- 2012 Natural Gas Master - 2**.

them more expensive to run.[247] For this reason, it is appropriate to regard the 1,200 hour threshold as integral to EPA's BSER determination for peaking units. Units operating above this threshold are no longer serving peaking functions and should instead be required to meet an emission standard that reflects NGCC, which is the best system of emission reduction for more heavily-utilized generating natural gas-fired units.

The data also show that operating CTs at varying annual capacity factors does not significantly impact efficiency, thus demonstrating that establishing an emission limitation based on the normal range of operation of these units is practicable. Figure 18 shows the average emission rate by hours of operation for CTs based on the CAMD data.

Fig. 18: Emission Rates by Hours of Operation – CTs
Source: 2012 CAMD Data Set



While there is a modest increase in the CO_2 emission rate from the lowest operating units (100—200 hours annually) compared to the highest operating units (3,000 hours annually),

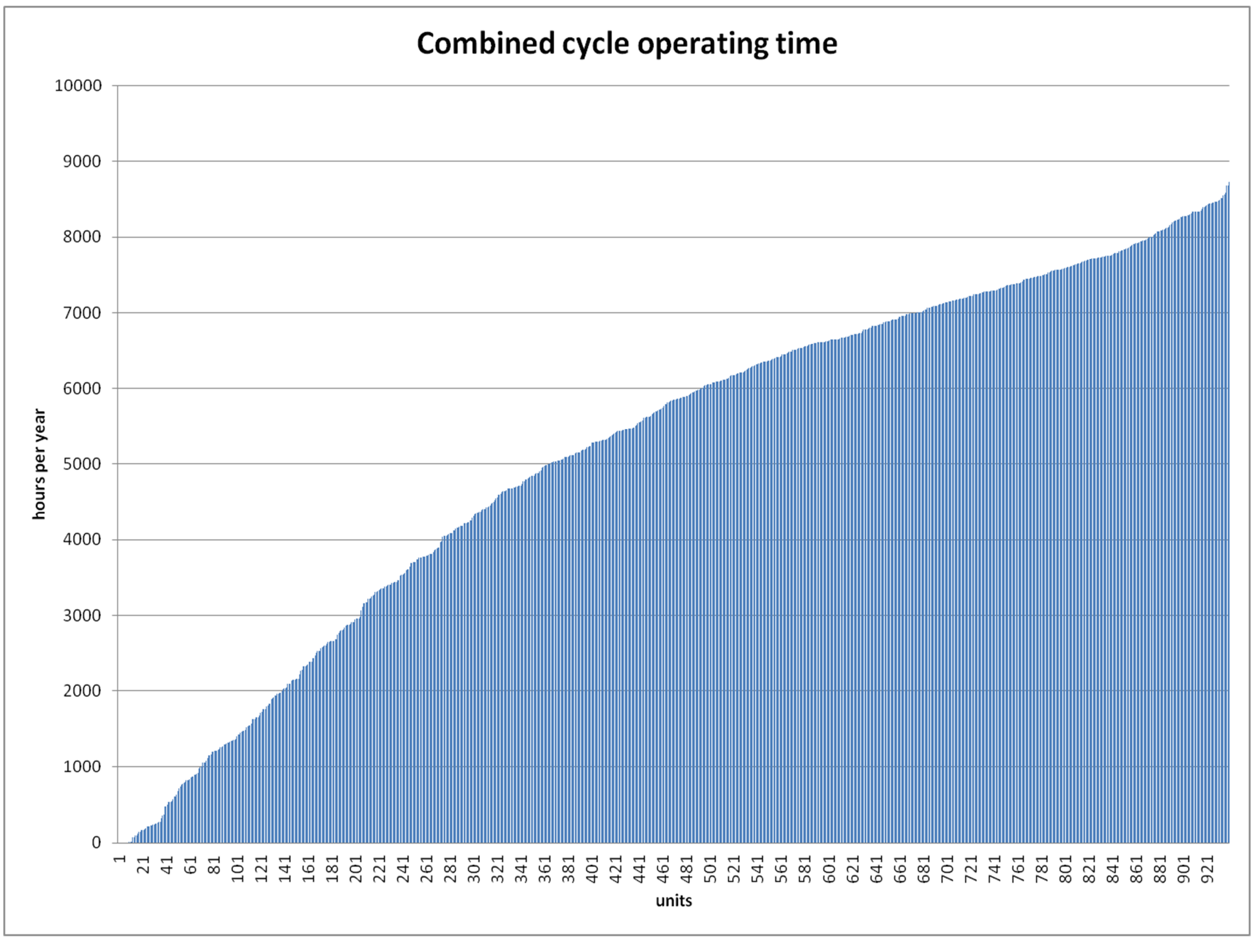
[247] Furthermore, EPA's failure to set a CO_2 emission limit for CTs might cause perverse incentives to develop more of these inefficient units.

most of the CT units in the data set had emission levels varying between 1,200 and 1,400 lb CO_2/MWh.

b. Intermediate/Load-Following and Baseload Units

In contrast to CTs, there is a much greater variation in the emission rate of CCGTs compared to their operating hours. Fig. 19 below shows the annual operating hours for all the combined cycle units in the 2012 CAMD data set.

Fig. 19: Annual Operating Hours – CCGT Plants
Source: 2012 CAMD Data Set



CCGTs also show much more variability than CTs in terms of operating hours. Whereas the vast majority of CT units operated under 1200 hours annually, CCGTs cover the full operational spectrum: the CAMD data on combined cycle units show a relatively smooth distribution ranging from less than 500 hours of annual operation up to a full 8,760 hours. Furthermore, the emission rates of CCGT plants change significantly depending on how frequently they run.

Figure 20 shows a significant decrease in emissions as units operate more hours over the course of a year.

Fig. 20: Emission Rates by Hours of Operation – CCGT Plants
Source: 2012 CAMD Data Set

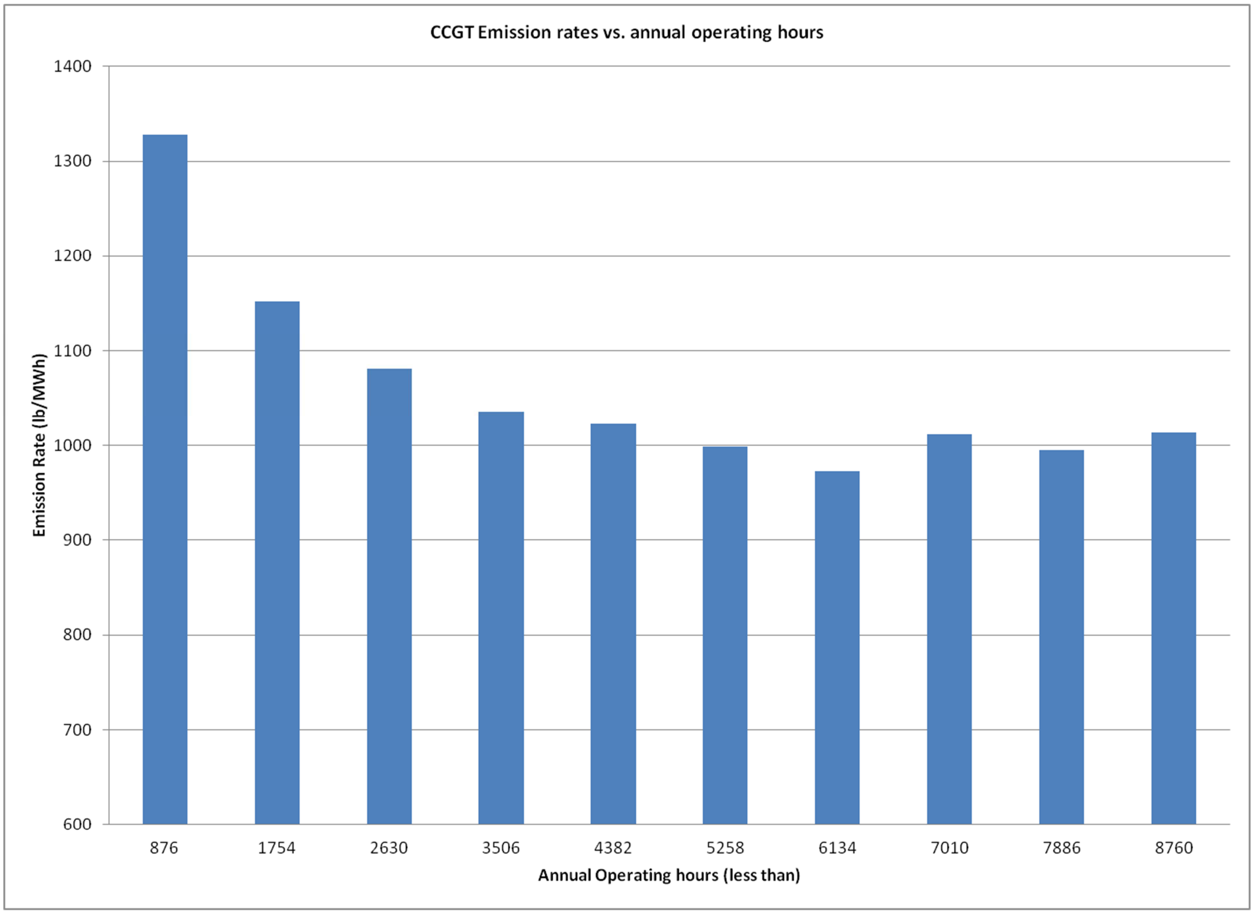


Figure 20 shows that existing CCGT units operating at or below 876 hours annually have much higher CO_2 emission rates compared to other CCGT units. Emission rates improve as the units operate more frequently until they reach about 4400 hours annually, where they begin to level out.

Joint Environmental Commenters compiled the aggregated CAMD data in Table 7 below to show the performance of both CCGT and CT units in the data set based on different tiers of operating hours. All emission rates are in lb CO_2/MWh, and show gross, net, and a 3 percent compliance margin figure (where applicable) on a net basis.

Table 7: Aggregate Emissions Data for CTs and CCGTs by Annual Hours of Operation
Source: 2012 CAMD Data Set

2012 Emission rate (lb/MWh) - key statistics	CT + CCGT > 4,000 hrs gross/net/ 3% compliance	CT + CCGT 1,200-4,000 hrs gross/net/ 3% compliance (average operating hours)	CT + CCGT < 1,200 hrs gross/net/ 3% compliance (average operating hours)
average of all units	995/1,025	1,080/1,112 (2,561)	1,368/1,409 (438)
median	879/905/932	978/1,007/1,038 (1,353)	1,321/1,361/1,401 (204)
average of top 10 percent	767/790/814	803/827/852 (2,692)	1,019/1,050/1,081 (589)
90th percentile unit	800/824/849	827/852/877 (2,799)	1,131/1,165/1,200 (477)
average of top 20 percent	789/813/837	822/847/872 (2,994)	1,164/1,199/1,235 (528)
80th percentile unit	818/843/868	849/874/901 (3,576)	1,189/1,225/1,261 (457)
average of bottom 10 percent	1,466	1,501 (2,416)	1,900 (308)
average of bottom 10-20th percent	1,303	1,349 (2,997)	1,582 (346)

Table 7 supports Joint Environmental Commenters' recommended emission limits for each class of CCGT units. The average performance of the top 10 percent of units that operated more than 4,000 hours annually (i.e., baseload plants), including a 3 percent compliance margin, is 814 lb CO_2/MWh. The average performance of the top 10 percent of units that operated between 1,200 and 4,000 hours annually (i.e., intermediate/load-following plants), including a 3 percent compliance margin, is 852 lb CO_2/MWh. Finally, the average performance of the top 10 percent of units that operated less than 1,200 hours annually (i.e., peaking units), including a 3 percent compliance margin, is 1,081 lb CO_2/MWh. These data show that in each tier, the top 10 percent performing units would exceed Joint Environmental Commenters' recommended performance standards limits for each operating tier, even assuming a 3 percent compliance margin. By contrast, these data show that only the bottom 10 percent of units operating more than 1,200 hours annually would exceed EPA's proposed limit of 1,000 lb CO_2/MWh.

We have elsewhere demonstrated that there is no clear correlation between the cost of a CCGT and its efficiency. *See* section IV.A, *supra*. Any additional capital cost that may be involved is more than offset by the fuel cost savings provided by these units.

c. Our Approach is Technically Feasible: CCGT Units Are Capable of Meeting Load-Following Dispatch.

Joint Environmental Commenters expect industry commenters to assert that emission limits for intermediate dispatch units (which they assert will be simple cycle CTs, not CCGTs) must be higher than the historic performance levels for units used as intermediate dispatch units, because as renewable generation grows, more CTs will be necessary to integrate those renewable sources into the electricity grid. Industry advanced this argument in comments to the April 2012 rule proposal, suggesting that EPA should not rely on historical data to set the standard for all natural gas units. Splitting the standard into separate subcategories based on hours of operation addresses part of industry's assertion that increased load-following will result in less efficient emissions. Our recommended intermediate dispatch subcategory would require an 875 lb CO_2/MWh (net) emissions standard, which is significantly less efficient than today's vendor statistics for combined-cycle designs for units typically considered for baseload operation. Our proposed intermediate limit is well within the capability of "fast response' CCGTs designed to support renewable generation. *See* Table 7, *supra*. The difference in proposed emission limits is specifically designed to account for any loss in efficiency due to the cycling that is necessary for load-following operations.

Industry's assertion that less efficient CTs are necessary for load-following operation is not correct. For the purposes of reliability and renewable integration, combined-cycle units are fully capable of providing fast-response generation. They are therefore fully capable of matching variable renewable output, and can satisfy load-following and immediate dispatch needs in manner comparable, if not identical, to simple cycle units. Siemens has published documentation showing that its Fast Start 30 is capable of 10 minute starts after an overnight shutdown.[248] Longer times necessary to reach full load are limited to circumstances where an operator elects to shut the unit down for more than 48 hours. There is no technological limitation requiring a unit to shut down for that period of time, but an operator may elect to do so if the unit will not be needed for that duration. However, even under this scenario, full output of the combustion turbines that are components of these units are available within 10 minutes.

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[248] *See* Siemens, *Siemens Gas Turbine SGT6-5000F Application Overview* (2008), at 4, 15, *available at* http://www.energy.siemens.com/hq/pool/hq/power-generation/gas-turbines/downloads/SGT6-5000F_ApplicationOverview.pdf, attached as **Ex. 89**; Modern Power Systems, *Fast-Cycling Toward Bigger Profits* (June 2007), *available at* http://www.modernpowersystems.com/features/featurefast-cycling-towards-bigger-profits/, attached as **Ex. 90**; Gülen, *Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept* (June 12, 2013), *available at* http://www.power-eng.com/articles/print/volume-117/issue-6/features/gas-turbine-combined-cycle-fast-start-the-physics-behind-the-con.html, attached as **Ex. 91**.

Accordingly, the performance standard for the intermediate tier should be set at a limit that modern fast-response CCGT units are capable of meeting, as a forward-looking matter, even if CT units cannot meet the limit. The performance capabilities of simple cycle turbines should not provide the base assumption for intermediate units because they are inherently less efficient, and are currently used primarily as peakers. Indeed, combined cycle units can act as peakers or load-following units by ramping up their combustion turbines very quickly, while still meeting full load simply by warming up the heat recovery steam generator in anticipation of increased demand. This point is important because the "peak" is rarely a surprise. Utilities are quite good at estimating peak demand based on weather and usage patterns. Thus, operators have sufficient time to warm up a combined-cycle unit to meet full-load needs, while at the same time having sufficient flexibility to dispatch units quickly at more than half of their full-load capacities within 10 minutes if an urgent need arises.

Illustrative of this point is NRG's gas-fired plant in El Segundo, California, which came online in September 2013. This facility operates in a combined-cycle configuration that is capable of the same startup times (12 minutes) as an identical unit in a simple-cycle configuration. A recent press release noted that the El Segundo plant can achieve even faster startup times: "The new plant can deliver more than half of its [550 MW] generating capacity in less than 10 minutes and the balance in less than 1 hour, which is needed as California relies more on intermittent renewable technologies like wind and solar that depend on weather conditions."[249]

There are several other examples of combined cycle units that can meet fast-start and quick ramping times in a manner comparable to simple cycle units. For example, Footprint Power's Salem Harbor Station will be capable of providing 300 MW of power to the grid "within 10 minutes" using GE's 7F 5-series gas turbine with its "Rapid Response" package.[250] The plant will reduce greenhouse gases as well as other pollutants including NO_x, SO_2 and mercury.[251] In addition, the plant's operators have touted its "flexibility" to enable integration of renewables onto the grid.[252] *See also 7F 5-Series Gas Turbine Fact Sheet* (indicating a start time of 11 minutes);[253] *7F 7-Series Gas Turbine Fact Sheet* (indicating start time of 10 minutes).[254]

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[249] Reuters, *NRG's California El Segundo Natgas Power Plant Enters Service* (Aug. 2, 2013), *available at* http://www.reuters.com/article/2013/08/02/utilities-nrg-elsegundo-idUSL1N0G317120130802, attached as **Ex. 92**.

[250] Press Release, *GE Technology to Repower Footprint Power's Salem Harbor Station, Reducing Emissions and Ensuring Reliable Electric Service for Greater Boston Area* (Nov. 1, 2013), *available at* http://www.genewscenter.com/Press-Releases/GE-Technology-to-Repower-Footprint-Power-s-Salem-Harbor-Station-Reducing-Emissions-and-Ensuring-Rel-43a6.aspx, attached as **Ex. 93.**

[251] *Id.*

[252] *Id.*

[253] GE, *7F 5-Series Gas Turbine Fact Sheet* (2012), *available at* http://www.ge-flexibility.com/static/global-multimedia/flexibility/documents/7F_5-series_Gas_Turbine_Fact_Sheet_FINAL.pdf, attached as **Ex. 94**.

Similarly, the proposed Oakley Generating Station in California has been designed with the capability to start up and dispatch quickly with GE's Rapid Response package.[255] The Rapid Response package will allow the plant to start up from warm or hot conditions in less than 30 minutes. The system achieves fast performance by initially bypassing the steam turbine when the gas turbines are first started up. In a conventional combined cycle system, the gas turbine must be held at low load for a period of time while the HRSG is warmed up and steam is gradually fed into the steam turbine to bring it up to operating temperature. This process must occur slowly in order to minimize thermal stresses on the equipment and to maintain the necessary clearances between the turbine's rotating and stationary components. In the past, this delay necessitated a slow warm-up of the HRSG and steam turbine, which meant that the plant's gas turbine could not increase load as rapidly as a simple-cycle turbine to quickly provide power to the grid. This method also resulted in increased emissions of air pollutants, including CO_2, because the combustion turbine remained at low load—where it operated less efficiently—while the HRSG and steam turbine warmed up. Those constraints are avoidable with today's technology. The GE Rapid Response system initially bypasses the steam turbine when the combustion turbines are started, allowing them to ramp up quickly and begin providing power to the grid. The steam turbine can then be warmed up slowly without requiring the combustion turbines to remain at low load (except for a short time during cold startups), which is achieved through the controlled admission of steam from the HRSGs into the steam turbine. The Rapid Response package therefore allows the facility to start up and begin providing power to the grid more quickly than a conventional system, achieving enhanced operational flexibility and reduced emissions associated with startups.

Another example of a currently operating facility that uses this technology is the 300 MW Lodi Energy Center, which came online in 2011 and can deliver 200 MW to the grid in 30 minutes.[256] The plant can also ramp up and down at a rate of 13.3 MW/min. This flexibility allows the unit to respond quickly to intermittent resources or demand while still complying with stringent California emissions requirements. The Siemens fast-start units are specifically designed to reduce the "thermal shock" or "thermal penalty" associated with ramping combined cycle units up and down. Furthermore, these units are available today, and demand

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[254] GE, *7F 7-Series Gas Turbine Fact Sheet* (2012)*, available at* http://www.ge-flexibility.com/static/global-multimedia/flexibility/documents/7F_7_Series_Product_Fact_Sheet.pdf, attached as **Ex. 95**.

[255] *See* Bay Area Air Quality Mgmt. Dist., *Final Determination of Compliance for Oakley Generating Station* (Jan. 2011), at 12, *available at* http://www.energy.ca.gov/sitingcases/oakley/documents/others/2011-01-21_BAAQMD_FDOC_TN-59531.pdf, attached as **Ex. 96**.

[256] *See* Isles, *Lodi's 300MW Flex 30 plant ushers in a new era for the US*, Gas Turbine World (Sept./Oct. 2012), *available at* http://www.gasturbineworld.com/assets/sept_oct_2012.pdf , attached as **Ex. 97**; Gawlicki, *Lessons from Lodi*, Public Utilities Fortnightly (Apr. 2010), *available at* http://www.fortnightly.com/fortnightly/2010/04/lessons-lodi, attached as **Ex. 98**.

for them is increasing.[257] In April 2013, Siemens was awarded a contract for a Siemens Flex Plant 30 fast-start unit at the Panda Temple II plant in Temple, TX.[258] Financing has been secured and construction of the plant has commenced.[259] Additional fast-response units will be constructed at the Palmdale Hybrid Energy Plant, where they will operate in conjunction with a 50 MW solar facility, and are also planned for inclusion at the proposed Huntington Beach Energy Project.

In addition, units designed by GE and other manufacturers are operating in other countries that, due to higher natural gas prices, have led the way in developing and adopting high efficiency, flexible natural gas-fired electric generating technology. GE asserts that it has orders totaling $1.2 billion for Flex Efficiency for 60 plants in the U.S., Japan and Saudi Arabia – countries that use 60-cycle electricity.[260] Likewise, the Severn Power Plant in Wales is capable of providing full load (834 MWh) within 30-35 minutes with a high degree of flexibility to compensate for intermittent resources such as wind.[261] The plant is the result of concerted efforts by turbine manufacturers to meet demand for flexible units with better efficiencies and lower emissions. Combined-cycle plants with enhanced flexibility and start-up capabilities have also appeared recently in France, England, the Netherlands, and Portugal.[262]

Lastly, data already included in the record indicates that units such as those described above can meet stringent CO_2 performance standards even when they undergo frequent cycling.[263] As part of its study of the performance of over three hundred NGCC units, EPA evaluated whether units that cycle more frequently exhibit higher CO_2 emission rates. Although the units included in the study pool had a wide range of cycling behavior, ranging

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[257] *See Siemens takes the early lead in the sale of packaged fast-start plants for the US market*, CCJ Onsite-Combined Cycle Journal (Oct. 21, 2012), *available at* http://www.ccj-online.com/siemens-takes-the-early-lead-in-the-sale-of-packaged-fast-start-plants-for-the-us-market-ge-rounds-out-the-activity-a-distant-second/, attached as **Ex. 99.**

[258] *See* Press Release, *Siemens receives order for EPC contract for power plant in the United States* (Apr. 04, 2013), *available at* http://www.siemens.com/press/en/pressrelease/?press=/en/pressrelease/2013/energy/fossil-power-generation/efp201304026.htm, attached as **Ex. 100.**

[259] *See* Press Release, *Panda Power Funds Secures Financing for Expansion of Temple, Texas Power Plant* (Apr. 04, 2013), *available at* http://newsroom.pandafunds.com/press-release/panda-power-funds-secures-financing-expansion-temple-texas-power-plant , attached as **Ex. 101**.

[260] *See* Press Release, *GE Launches Breakthrough Power Generation Portfolio with Record Efficiency and Flexibility with Natural Gas; Announces Nearly $1.2 Billion in New Orders* (Sept. 26, 2012), *available at* http://www.genewscenter.com/Press-Releases/GE-Launches-Breakthrough-Power-Generation-Portfolio-with-Record-Efficiency-and-Flexibility-with-Natural-Gas-Announces-Nearly-1-2-Billion-in-New-Orders-3b54.aspx, attached as **Ex. 102**.

[261] *See* Balling, *Fast cycling and rapid start-up: new generation of plants achieves impressive results*, Modern Power Systems (Jan. 11), at 7, *available at* http://www.energy.siemens.com/hq/pool/hq/power-generation/power-plants/gas-fired-power-plants/combined-cycle-powerplants/Fast_cycling_and_rapid_start-up_US.pdf, attached as **Ex. 103**.

[262] *See id.* at 2.

[263] Gas TSD at 6.

from to 1,553 starts per year, EPA found "limited correlation" between the number of starts and CO_2 emission rates. In addition, EPA found that the average CO_2 emission rate of the ten units that cycled most frequently was 883 lb/MWh, which is very close to our recommended standard for intermediate load units. These results confirm that load-following units are capable of meeting an emission standard that is much more stringent than the 1,000 and 1,100 lb/MWh standards that EPA has proposed.

These examples demonstrate that the feasibility of fast-start and quick-ramping combined-cycle turbines has advanced substantially. It is factually inaccurate to claim that combined-cycle units are incapable of meeting the technical function of a load-following unit. Advances in HRSG technology have allowed for faster response times with reduced or even eliminated thermal penalties. In short, CTs are unnecessary—and unnecessarily dirty—options for intermediate and load-following services, and EPA should not dilute the performance standard for gas plants in order to accommodate those less efficient technologies.

C. EPA Must Consider Solar-Hybrid CCGT Units

In addition to considering the performance of the existing CCGT units as the standard for BSER, EPA must also consider and incorporate the performance improvements that can be reasonably anticipated, such as CSP/ CCGT hybrids.[264] An example of this technology is the Palmdale Hybrid Power Plant, which has received PSD approval from EPA and is slated for construction. Plans for this facility include a 2-on-1 combined cycle configuration with two GE-7FA gas turbines and one steam turbine to produce a nominal electrical output of 563 MW, of which up to 50 MW will be produced from a solar thermal collection field.[265] This project will use the solar thermal auxiliary heat, in combination with the HRSG, to power the steam generator. This hybrid configuration is expected to yield a much better source-wide GHG emission rate, since solar thermal energy will displace some of the duct firing for the steam turbine. The PSD permit for this facility, issued by EPA Region 9, establishes a source-wide GHG BACT limit of 774 lb CO_2/MWh.[266]

Another proposed hybrid facility is the Victorville 2 plant. This planned 570 MW generating station will achieve a thermal efficiency of 59.0 percent when using thermal solar hybrid technology to preheat water for the HRSG system, a process similar to Palmdale's. This configuration is expected to achieve a 6.3 percent gain in thermal efficiency compared to the

[264] CSP can and has been retrofit to existing CCGTs, most notably at the Martin Next Generation Solar Energy Center, where 75 MW of CSP capacity was added to an existing 3,750 MW natural gas-fired plant.

[265] *See* EPA Region 9, *Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Project* (Oct. 18, 2011), at 1-3, *available at* http://www.epa.gov/region9/air/permit/palmdale/palmdale-final-permit-10-2011.pdf, attached as **Ex. 104.**

[266] *Id.* at 8.

Victorville 2 plant using duct burners.[267] It is also 9.1 percent higher than the proposed LPEC heat rate of 49.9 percent.[268] Given the superior performance of CSP/ CCGT hybrid units in terms of thermal efficiency and CO_2 emissions, as well as its demonstrated availability, EPA should consider whether this technology constitutes BSER for natural gas-fired EGUs.

X. Net Emissions vs. Gross Emissions

EPA proposes to set CO_2 emissions standards for both industrial categories (Da and KKKK) on a gross-output basis, rather than on a net-output basis. The agency does this despite acknowledging, as it did in its now-withdrawn 2012 proposal, that "the net power supplied to the end user is a better indicator of environmental performance than gross output from the power producer."[269] We agree with the agency that

> [r]easons for using net output include (1) recognizing the efficiency gains of selecting EGU designs and control equipment that require less auxiliary power, (2) selecting fuels that require less emissions control equipment, and (3) recognizing the environmental benefit of higher efficiency motors, pumps, and fans.[270]

Therefore, in response to the Agency's solicitation of comments on setting the standards on a net-output rather than gross-output basis, Joint Environmental Commenters assert that EPA's final standards must take advantage of *all* opportunities to promote more efficient designs of all coal- and gas-fired facilities, including those provided by setting the standard on a net-output basis for all affected facilities. EPA must avail itself of such opportunities for the resulting standard to truly effectuate the statute's technology-forcing purpose.

One stated objective of EPA's proposal is to encourage the development and use of more efficient generation technologies (*i.e.*, those that emit fewer pounds of pollutant per unit of electricity sold to the grid).[271] But EPA's proposed gross-output based standard actually discourages this result by ignoring the amount of electricity that the facility uses before it sells the electricity to the grid. That is because a gross-output based standard merely tracks the *total* amount of electricity generated per unit of pollutant emitted. By contrast, under a net-output based standard, compliance is determined based on the amount of electricity *made available* to the grid per unit of pollutant emitted. Thus, a net-based standard better promotes "technology

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[267] *See* City of Victorville and Inland Energy, Inc., *Application for Prevention of Significant Deterioration Permit for Victorville 2 Hybrid Power Project*, Doc. No: 10855-001-040a (Apr. 2007), *available at* http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2008-0406-0001**,** attached as **Ex. 105.**
[268] *Id.* at 48.
[269] 79 Fed. Reg. at 1448.
[270] *Id.* at 1446.
[271] *See, e.g.*, *id.* at 1460 (noting that one reason for proposing a different definition of "potential electrical output" is that the current definition does not account for the efficiency of the unit).

forcing" throughout the industry by encouraging the selection of more efficient electric generating unit designs. It also provides incentives over the long run for further research and development of even more energy efficient control processes and equipment, for all types of electrical generating facilities. Therefore, if the Agency finalizes a gross-output based standard, it will not have fully effectuated the technology-forcing purpose—and promise—of section 111.[272]

EPA recognizes this purpose, noting a concern that if the standard is not stringent enough, it would fail to create the incentives needed for the innovation in pollution control through techniques that provide significant CO_2 reductions.[273] EPA's reasoning (with which we generally agree) is that the standard must achieve one of the statute's key objectives - facilitating the development and deployment of lower emitting options such as CCS and/or other possible technologies that can achieve even greater percentage emissions reductions in the long term. Such objectives drive the selection of partial CCS (slightly less than 25 percent capture for an IGCC unit) with an emission rate equivalent to 1,400 lb CO_2/MWh (net-output) as proposed.[274] EPA is misguided, though, to argue that a gross-output standard is needed to accomplish such "technology forcing;" in fact the opposite is true – a net-output based standard better provides the necessary incentives to move technology that incremental step forward towards not only deeper reductions, but deeper reductions that can be achieved more efficiently.

Current generation IGCC or ultra-supercritical ("USC") plants are able to achieve emission rates of 1,600 lb CO_2/MWh (net-output) using 100 percent coal without any capture technology. Future development of an advanced ultra-supercritical plant ("AUSC") is projected to lead to design emission rates of less than 1,500 lb CO_2/MWh (net-output)[275] but not without

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[272] *See* Ashford *et al.*, *Using Regulation to Change the Market for Innovation*, 9 HARV. ENV. L. REV. 419, 466 (1985), attached as **Ex. 106** (concluding that the regulatory process "can be used both to stimulate technological change for health, safety, and environmental purposes and bring about a desirable restructuring of the industrial process").

[273] 79 Fed. Reg. at 1471 ("We are not currently considering a standard above 1,200 lb CO_2/MWh because at that level, the NSPS would not necessarily promote the development of CO_2 emissions control technology or provide significant CO_2 reductions. At an emissions rate of 1,300 lb CO_2/MWh, IGCC facilities would only be required to capture approximately 10 percent of the CO_2, and many designs would have a sufficient compliance margin that they would not need to use a WGS reactor. Further, an owner/operator of an IGCC facility could comply with this standard without the use of any CCS. For example, a new IGCC facility designed to co-fire 20 percent natural gas or using fuel cells instead of combustion turbines could comply with an emissions rate of 1,300 lb CO_2/MWh without the use of CCS.").

[274] *See id.* at 1448, Table 4.

[275] These figures are endorsed and cited by both the World Coal Association and the National Coal Council. See, e.g., World Coal Institute, *Coal Meeting the Climate Challenge* (2007), at Figure 5 and Table 9, *available at* http://www.worldcoal.org/bin/pdf/original_pdf_file/coal_climate_change_css_report(03_06_2009).pdf, attached as **Ex. 107**; The National Coal Council/U.S. DOE, *Opportunities to Expedite the Construction of New Coal-Based Power Plants* (at Figure 2.2,

a regulatory driver.[276] With a small percentage of natural gas co-firing or a solar preheating system, such units might well comply with EPA's proposed standard, but only if the associated emission limitation standard was set on a net output basis.[277] However, these units' future compliance with EPA's proposed gross-output emission rate of 1,100 lb CO_2/MWh could not be achieved because such non-CCS units would not have the large parasitic loads associated with CCS. As shown in Table 8 below, without that load their gross emission rates would be much closer to net emission rates and higher than the proposed limit. Thus, a net-output based standard would promote more flexibility to the facility in finding new, innovative ways to comply while still preventing substantial CO_2 emissions.

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available at http://www.nationalcoalcouncil.org/Documents/ExpediteNov30rpg.pdf. These figures are also consistent with figures published by EIA, EPRI, and several vendors of coal-fired power plants, including Hitachi, Dong Energy, Siemens, and Babcock & Wilcox. *See, e.g.*, Armstrong et al., Hitachi, *Design and Operating Experience of Supercritical Pressure Coal Fired Plant*, *available at* http://www.hitachipowersystems.us/supportingdocs/forbus/hpsa/technical_papers/EP2003A%20Design%20and%20Operating%20Experience%20of%20Supercritical%20Pressure%20Coal%20Fired%20Plant.pdf, attached as **Ex. 108**; Bugge et al., *High-Efficiency Coal-Fired Power Plants. Development and Perspectives*, at 4, *available at* http://www.dongenergy.com/SiteCollectionDocuments/NEW%20Corporate/PDF/Engineering/45.pdf attached as **Ex. 109**; Cziesla et al., Siemens AG, Energy Sector, *Advanced 800+ MW Steam Power Plants and Future CCS Options* (Sept. 2009), at 2 *available at* http://www.energy.siemens.com/nl/pool/hq/power-generation/power-plants/steam-power-plant-solutions/coal-fired-power-plants/CGE09-ID34-Advanced-SPP-Cziesla-Final.pdf , attached as **Ex. 110**; Weitzel, Babcock & Wilcox, *Steam Generator for Advanced Ultra-Supercritical Power Plants 700 to 760 C*, Technical Paper BR-1852 (2011), *available at* http://www.babcock.com/library/Documents/BR-1852.pdf, attached as **Ex. 111**; Bennett, Babcock & Wilcox, *Progress of the Weston Unit 4 Supercritical Project in Wisconsin*, Technical Paper (2006), *available at* http://www.babcock.com/library/Documents/BR-1790.pdf , attached as **Ex. 112**.

[276] *See* Ashford *et al.*, *supra* n. 272, at 462-66 (concluding that regulation is an effective way to drive innovation within an industry); Taylor *et al.*, *Regulation as the Mother of Innovation: The Case of SO_2 Control*, 27 Law & Policy, No. 2, at 371-72 (April 2005) (noting the importance of regulations in driving advancement of SO_2 control technology).

[277] *See* 79 Fed Reg. at 1471. EPA notes that "a new IGCC facility designed to co-fire 20 percent natural gas or using fuel cells instead of combustion turbines could comply with an emissions rate of 1,300 lb CO_2/MWh [gross output]" without the use of any capture technology. *Id.* For this type of facility, which has a much lower parasitic load than facilities using CCS, the corresponding net output-based standard is 1,400 lb CO_2/MWh, the equivalent of a standard of 1,100 lb CO_2/MWh on a 100 percent coal-fired facility utilizing 25 percent capture.

Table 8: Comparison of Net, Gross, and Adjusted Gross Emissions of Different Coal Configurations
Source: EPA, Preamble to GHG NSPS Rule Proposal[278]

Technology	Net emission rate	Adjusted gross emission rate	Gross emission rate
Coal with 25% CCS	1,400	1,300	1,100
Hybrid/co-fire w/o CCS	1,400	1,300	1,300

This comparison also highlights how EPA's proposed usage of a gross-output based standard may obscure the scope of the improvements that are potentially available from the proposed standard. By comparing gross emission rates (and ignoring the GHG emissions from the energy that it takes to operate CCS) EPA asserts that it estimates "this standard will result in reduction in emissions of at least 40 percent when compared to the expected emissions of a new SCPC boiler."[279] While it is true that the actual CO_2 emissions of a unit meeting EPA's proposed gross-output based standard would emit less CO_2 than would a new, high efficiency SCPC unit, that reduction is closer to 15-20 percent when analyzed on a "pounds-of- CO_2 -per-unit-of-electricity-delivered-to-a-consumer" basis.[280] In other words, the gross output standard overstates the real world impacts of the standard by at least factor of 2.

A gross output standard also inappropriately biases the future development of CCS, and other equal or better carbon dioxide control options, by providing a distinct and unwarranted advantage to IGCC units over AUSC units with CCS. EPA has proposed to address this particular issue with a third unit of measurement—an "adjusted gross output" standard in which the electric load needed to power the additional IGCC equipment is subtracted from the gross load. Because IGCC units have a much higher ancillary load than AUSC units,[281] if one discounts the emissions associated with this load, an IGCC unit would only have to capture 25 percent of the CO_2 emissions from the unit to comply with the proposed standard while an AUSC unit would have to capture 40 percent. This would result in substantially greater real world CO_2 emissions from the IGCC unit and an unwarranted cost advantage for IGCC/CCS units over AUSC/CCS units. There is no reason for EPA to create this distinction. Any advantages to IGCC/CCS units will be revealed, promoting the technology without the need for special treatment. Moreover, there is no need for a separate treatment regardless, as EPA should finalize standards on a net-output basis for all units.

[278] *See id.* at 1448, 1471.
[279] *Id.* at 1471.
[280] 1,600 lb CO_2/MWh (net) – 1,400 lb CO_2/ MWh (net) = 200 lb CO_2/MWh (net); 200/1600 = 12.5 percent. Using NETL's figure of 1,768 lb CO_2/MWh (net) for a less efficient USC as the baseline, EPA's proposal would represent a 21 percent reduction in emissions.
[281] In general, less than 7.5 percent of non-IGCC and non-CCS coal-fired station power output, approximately 15 percent of non-CCS IGCC-based coal-fired station power output, and about 2.5 percent of non-CCS combined cycle station power output is used internally by parasitic energy demands.

EPA asserts that the technologies it has considered for its 1,100 lb CO_2/MWh (gross-output) proposal can also achieve a level of 1,000 lb CO_2/MWh (gross-output).[282] Thus, Joint Environmental Commenters recommend EPA finalize an emission level of 1,200 lb CO_2/MWh (net-output), which EPA asserts is equivalent to 1,000 lb CO_2/MWh (gross).[283] There should not be a significant cost increase associated with a somewhat more stringent net emissions limit than proposed. Since, as described above, IGCC units without CCS have relatively high parasitic loads, setting the standard at the levels we suggest on a net-output basis would preclude compliance by IGCCs that co-fire relatively small percentages of natural gas. Because any IGCC/CCS unit would likely be a baseload unit, if fired on natural gas the CCGT portion of the IGCC would meet an emission limit of less than 850 lb CO_2/MWh (net-output). For this reason, the flexibility of operation, by way of co-firing an IGCC with natural gas, which the agency seeks to promote can still be readily achieved at a lower level than proposed. Moreover, EPA's proposal would apply the Subpart KKKK standard to any IGCC that fires above a given percentage. If set at an appropriate level, similar to those recommended in section IX, *infra*, this feature of the rule would preclude gaming of the partial CCS rule as EPA suggests.

Additionally, EPA suggests that determining the net output of an IGCC facility could be "more challenging to implement." 79 Fed. Reg. at 1447. But this would entail simply measuring the electricity associated with the primary gas compressors for electricity production—and EPA has not explained why this measurement would be "challenging."[284] The agency's assertion simply does not support the proposed gross-output based emission standard for IGCC units, nor for subpart Da and KKKK units more generally. While it is generally "more challenging" to do something than it is *not* to do something, this does not supply EPA with a proper rationale to opt for a gross-output standard in the proposed rules.

Joint Environmental Commenters urge the agency to finalize rules that provide impetus for improving the efficiency of all generating technologies, including IGCC, through net-output based standards, because it is simply not the case that measuring net electric output poses too burdensome of a technical or financial challenge today – particularly for newly constructed units. It cannot be "more challenging" to require an operator to submit basic information for a *new* unit that it already gathers, apparently without difficulty, for *existing* units. In fact, EPA has ready access to net metering data, and net electrical metering has become common in the industry for reasons set out by FirstEnergy fifteen years ago:

> Net power generation is the marketable product of a commercial power plant, and as the power industry moves into a deregulated environment, there is a strong impetus to even more accurately measure net output to the electrical grid. It is expected that one "point of sale" of this product will be the interconnection between the power plant and the transmission grid. This connection point is generally accepted to be at the high voltage side of the step-

[282] 79 Fed. Reg. at 1470.
[283] *Id.* at 1448, Table 4.
[284] *See id.* at 1447.

up transformer, net of all plant auxiliary use of electricity and transformer losses. As utility services are unbundled into distinct generation and transmission entities, the independent transmission organizations which are currently forming will be developing new performance standards for the accurate metering of electricity. FirstEnergy has established a corporate-wide standard for unit-level net MWh output in anticipation of these requirements. These industry upgrades to net output metering will proceed due to market forces concurrent with deregulation, independent of any separate environmental regulatory initiatives.[285]

EPA explains its continued preference for a gross output based standard by stating that the agency "only ha[s] CEMS emissions data reported on a gross output basis because that is the way the data is currently reported under 40 CFR Part 75." 79 Fed. Reg. at 1448. However, this statement is inaccurate and largely irrelevant in setting standards for new coal-fired units with CCS. In this rulemaking, EPA is not setting an emission limit for either existing or new coal-fired units without CCS. Part 75 data does not yet include emission data for CCS-equipped coal-fired units and EPA does not rely on any Part 75 emission data in support of its proposed emission limit for new fossil-fuel fired steam EGUs. EPA bases the selection of the proposed level of capture in part on a policy preference to keep the levelized cost of electricity for new coal plants at or below that of new nuclear units and to allow development of a fossil fuel-fired standard on an output basis. Thus, the fact that Part 75 data include gross electrical output is not relevant to a determination of the numerical emission limit associated with a BSER of partial CCS for fossil fuel-fired steam EGUs.

Indeed, the fact that facilities calculate, and EPA has access to, emissions on a net-output basis further demonstrates the Agency's flawed reasoning in further justifying a gross-based standard based on a claim that it only has "CEMS emissions data reported on a gross output basis because that is the way the data is currently reported under 40 CFR Part 75."[286] This statement is misleading in light of the above. Facilities can easily calculate emissions data on a net-output basis, regardless of Part 75 requirements, as evidenced by the above statement and the reports from the National Energy Technology Laboratory ("NETL"), which includes detailed cost- and performance-analyses for new, state-of-the-art units with CCS providing both net and gross CO_2 emission rates.[287] Moreover, EPA has relied on this data, in part, to support

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[285] FirstEnergy Corporation*, Measurement Of Net Versus Gross Power Generation For The Allocation Of NO_x Emission Allowances* (Jan. 27, 199), at 3, attached as **Ex. 113**

[286] 79 Fed. Reg. at 1449.

[287] *See e.g.,* NETL, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,* Revision 2a, 2013 DOE/NETL-2010/1397 (Sept. 2013), attached as **Ex. 114**; NETL, *Cost and Performance Baseline for Fossil Energy Plants Volume 3: Low Rank Coal to Electricity: Combustion Cases,* DOE/NETL – 2011/1663 (March 2011), *at* Exhibit ES-2: Cost and Performance Summary and Environmental Profile for Combustion Cases, attached as **Ex. 115** (in which the CO_2 emission rate for a USC plant combusting bituminous coal is given as 1,675 lb CO_2/MWh (gross) and 1,768 lb CO_2/MWh (net) for the zero carbon capture case and 203 lb CO_2/MWh (gross) and 244 lb CO_2/MWh (net) for the 90 percent capture case.

its choice of BSER[288], indicating that it is aware that facilities calculate emissions data on a net-output basis. In fact, EPA proposes to use net output data as a foundation of its rule. Although EPA proposes to establish the emission limitation on a gross-output basis, it also proposes that a source must determine whether it is an affected facility on the basis of the facility's net electrical output.[289] This requirement further, and substantially, undercuts the agency's argument that determining net-output is too difficult to require of new sources subject to the regulation.

Additionally, even without a Part 75 requirement to do so, electricity generators are still currently required to report monthly gross *and net* generation data to EIA using EIA Form 923.[290] These data allow EPA to determine the net generation directly for many units and, for other units, to convert the gross generation reported for each unit in its data set to net generation. Where a single unit serves a single generator, the conversion is fairly simple. For example, the Tennessee Valley Authority ("TVA") reports to CAMD/AMPD that 2009 gross generation from its Bull Run plant (ORISPL 3396) is 3,553,041 MWh; eGRID[291] lists 2009 net generation for this plant at 3,311,274. The net CO_2 emission rate for this plant is 1,832 lb CO_2/MWh (net-output, based on eGRID), while a simple calculation using CAMD/AMPD (gross generation divided by emissions) yields 1,699 lb CO_2/MWh (gross-output). Thus, for this unit, the net emission rate is 1.073 times the gross emission rate.

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[288] *See, e.g.*, EPA*, Costing Analysis for Partial CCS Memo*, EPA-HQ-OAR-2013-0495-0080 (Sept. 2013), Attachments 1-3, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0080.

[289] A source is subject to the gross output-based limits if it supplies more than one-third of its potential electric output and more than 219,000 MWh *net electric output* to a utility power distribution system for sale on an annual basis. Potential electric output is defined as either 33 percent of the design net electric output efficiency or 33 percent of a facility-specific calculation of the design net electric output efficiency of the facility. *See* 79 Fed . Reg. at 1502 & 1506 (Proposed 40 C.F.R. §§ 60.46Da(a)(2) and (k)), 1506 & 1510 (Proposed 40 C.F.R. §§ 60.4305(5), 60.4421), 1511 & 1516 (Proposed 40 C.F.R. §§ 60.5509(a)(1)-(2), 60.5580).

[290] *See* EIA, Form EIA-923: Power Plant Operations Report Instructions, OMB No. 1905-0129 (Exp. Dec. 31, 2015), at 14, attached as **Ex. 116**, which reads as follows:

"Gross Generation: Enter the total amount of electric energy produced by generating units and measured at the generating terminal. For each month, enter in the MWh generated.

Net Generation: Enter the net generation (gross generation minus the parasitic station load, i.e. station use). If the monthly station service load exceeded the monthly gross electrical generation, report negative net generation with a minus sign. Do not use parentheses. For each month, enter that amount in MWh. Combined heat and power plants in the industrial and commercial sectors may choose to leave net generation blank in cases where net generation cannot be determined. Please note that net generation is not defined as electric power sold to the grid (net of direct use), but as gross minus station use. If station use is not separable from direct use at combined heat and power plants, report only gross generation and leave net generation blank."

[291] eGRID2012 Version 1.0 Plant File (Year 2009 Data) *available at* http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012_Version1-0.zip, attached as **Ex. 117**.

Where multiple boilers serve one or more generators the calculation is more complex, but EPA has developed protocols for allocating criteria emission rates in these circumstances and one does not need individual unit data for purposes of standard setting. Plant Gibson has 5 boilers with similar controls. eGRID plant level data show a net emission rate 1.084 higher than the AMPD gross emission rate for that plant. The AMPD data are unit specific, while the published eGRID data are only provided at the plant level. But the average of plant level data that aggregate individual unit information will be the same as the average of all individual units. Regardless, for single or multiple boilers, plant level data is sufficient to determine a reasonable factor for converting gross output data to net at the final standard setting stage.[292]

Additional data on the relationship between net and gross electric output of specific units and the achievable emission levels are available in permit files for new units seeking BACT determinations or PUC approvals.[293] We note that in December of 2013, EPA Region IV issued a PSD permit for the reconstructed FPL Port Everglades facility that contained a 12-month limit of 830 lb CO_2e/MWh on a *net* emissions basis.[294] Clearly, a new facility has the ability to keep track of its emissions on a net-output basis.

Joint Environmental Commenters also agree with the Agency that one of the key purposes of the proposed rule is to serve as a necessary "predicate for the regulation of existing sources within this source category under CAA section 111(d)." 79 Fed. Reg. at 1496. It is important to preserve the ability to encourage all available options to reduce emissions from EGUs, including efficiency improvements and reductions in parasitic loads. This is another extremely important reason to employ a true net-output standard.

We also note that EPA should not allow sources an option to choose a net or gross output standard. As we point out above, a gross output standard fails to promote the agency's goal of encouraging the development of more and more efficient control options for carbon

[292] EPA's argument that it does not have sufficient information to convert net output to gross output for coal-fired units is undercut by its prior use of other conversion factors in other NSPS rulemaking efforts. *See, e.g.*, Memorandum from Weyland, R. to Maxwell, W., *Revised new source performance standard (NSPS) statistical analysis for mercury emissions*, EPA(D243-01) (May 31, 2006) at 7, attached as **Ex. 118** (factor of 1.056 used to convert the results of its input energy based analysis for the Hg NSPS for coal-fired units to an output based standard). EPA could easily calculate a similar conversion factor here to apply to a gross-to-net calculation.

[293] *See, e.g.*, Email from S. O'Kane to Cal. Energy Comm'n, re: Heat Rate Tables, CEC Docket 12-AFC-02, TN # 68934 (Dec. 19, 2012, docketed Dec. 20, 2012), attached as **Ex. 119.** *See also* EPA, Combustion Turbine Standard TSD, EPA-HQ-OAR-2013-0495-0082 (Sept. 2013), Attachment 2: Permits Spreadsheet (listing PSD permit applications), *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0082.

[294] EPA Region 4, *Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions* (Nov. 25, 2013), available at http://www.epa.gov/region04/air/permits/ghgpermits/porteverglades/PortEverglades_FinalPermit_112513.pdf , attached as **Ex. 120**.

dioxide. Moreover, it also results in more real world CO_2 emissions (per unit of electricity sold). Indeed, the fact that EPA is considering providing the option for facilities to choose demonstrates our point—that net-output standards are feasible. EPA has not provided any analysis in this proposal or the materials accompanying it of the additional emissions that might result from offering sources the opportunity to choose between net and gross output based standards.

XI. Monitoring, Compliance, and Enforcement Issues

EPA's proposed monitoring and compliance scheme provides a workable system in many respects. In particular, Joint Environmental Commenters appreciate that the proposed rule abandons EPA's earlier strategy of using an "average of 12 monthly averages" technique to determine compliance. The average of 12 monthly averages method of calculation would have distorted actual performance by overly weighting emissions during months of extremely low generation, and EPA has wisely omitted it from the current proposal. *Compare* 77 Fed. Reg. at 22,438 (initial proposed 40 C.F.R. § 60.5540(a)(3)-(5)) *with* 79 Fed. Reg. 1513-14 (current proposed 40 C.F.R. § 60.5540(a)(2)-(5)). Joint Environmental Commenters also recognize EPA's effort in the proposed rule to provide helpful clarity on how the agency may calculate penalties for violations of the standards. While additional clarification is needed, as we discuss below, the attention EPA gives to enforcement issues in this rulemaking can greatly smooth implementation of the standards.

However, the compliance program laid out in the proposed rule does have several critical shortcomings that must be addressed to achieve transparency and to meet the legal requirement that the rule be enforceable as a practical matter.

- First, the agency's proposed affirmative defense for violations attributable to malfunctions is both unlawful and an impediment to effective enforcement of the standards.
- Second, the proposed rule provides no safeguards to ensure sources will be able to comply with the performance standards. EPA must adopt measures to guarantee compliance with the NSPS.
- Third, EPA must ensure that penalties are sufficient to deter violations through daily compliance determinations, and should clarify penalties for violation of the 95 percent valid data requirement.
- Fourth, because the use of CEMS has been shown to be a feasible and inexpensive means for monitoring compliance, EPA's proposal of a less accurate alternative—fuel monitoring—is arbitrary and contrary to the statutory purposes.
- Finally, the record retention requirements pose potential obstacles to EPA's compliance investigations, and must be strengthened.

A. EPA's Proposed Affirmative Defense Is Unlawful and Arbitrary

Joint Environmental Commenters applaud EPA's recognition that the proposed performance standards must apply at all times, including during periods of startup, shutdown, and malfunction ("SSM"). *See* 79 Fed. Reg. at 1448-49. In *Sierra Club v. EPA*, 551 F.3d 1019, 1027-28 (D.C. Cir. 2008), the D.C. Circuit made clear that, under the Act, emissions standards require "continuous" compliance. Accordingly, the Court rejected a regulatory provision exempting sources from section 112's emission standards during SSM events. *Id.* Notably, *Sierra Club's* holding is not limited to the context of section 112, but applies as well to section 111 performance standards. This is because the court's ruling turned on the correct interpretation of the word "continuous" as it appears in the CAA's definition of "emission limitation," 42 U.S.C. § 7602(k), a term that is incorporated into section 111's definition of "standard of performance." *Id.* § 7411(a)(i). EPA therefore has properly proposed that performance standards for coal and gas plants must apply at all times, including during SSM events.

Nonetheless, the agency has also proposed an affirmative defense to civil penalties for any source that violates the performance standard due to a malfunction event. *See* 79 Fed. Reg. at 1449-50, 1512 (proposing 40 C.F.R. § 60.5530). This affirmative defense is unlawful under the Clean Air Act, as recently explained by the D.C. Circuit in *Natural Resources Defense Council v. EPA*, No. 10-1371 (D.C. Cir. Apr. 18, 2014) ("*NRDC*"). *NRDC* held that EPA lacked authority to promulgate, as part of a section 112 emission standard, an affirmative defense to civil penalties that is virtually identical to the one EPA proposes here. The court explained that this affirmative defense was contrary to sections 304(a) and 113(e)(1) of the Act because "Section 304(a) clearly vests authority over private suits in the *courts*, not EPA." *Id.* at Slip Op. 15-16 (emphasis in original).[295] *NRDC* also reiterated that when statutes vest courts with such authority, neither EPA nor any other administrative agency may limit the courts' consideration of available remedies. *Id*. at Slip Op. 15 (citing *City of Arlington v. FCC*, 133 S. Ct. 1863, 1871 n.3 (2013)); *see also Nehmer v. U.S. Dept. of Veterans Affairs*, 494 F.3d 846, 860 n.6 (9th Cir. 2007) ("An executive agency possesses no such power to strip a federal court of its jurisdiction.").[296]

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[295] Section 304 provides a mechanism by which "any person" may bring a civil action, over which the federal district courts shall have jurisdiction, including jurisdiction "to apply any appropriate civil penalties." *NRDC*, No. 10-1371, Slip Op. 15 (quoting 42 U.S.C. § 7604(a)). Section 113(e)(1) enumerates factors that courts shall consider when assessing civil penalties.

[296] *NRDC*'s holding that EPA cannot deprive courts of their jurisdiction to weigh the section 113(e)(1) factors is consistent with circuits that have held that the statutorily enumerated factors and mandates regarding fee assessments under analogous Clean Water Act sections may not be ignored—not even by courts themselves. *See, e.g., United States v. Lexington-Fayette Urban Cnty. Gov't*, 591 F.3d 484, 488 (6th Cir. 2010) (collecting cases from the Fourth, Sixth, Ninth, and Eleventh Circuits); s*ee also, e.g.*, *Sackett v. EPA*, 622 F.3d 1139, 1146-47 (9th Cir. 2010) *cert. granted in part*, 131 S. Ct. 3092 (2011), *rev'd on other grounds by* 132 S. Ct. 1367 (2012) ("[T]he [Clean Water Act's] civil penalties provision is committed to judicial, not agency, discretion."). Similarly, even if EPA, rather than courts, bore responsibility for applying the section 113(e) factors, the agency would still be required to consider all such factors when assessing a penalty. 42 U.S.C. § 7413(e)(1); *see also N.Y. Cross Harbor R.R. v. Surface*

The relevant section 304(a) and section 113(e)(1) provisions described above affect not only the section 112 standards at issue in *NRDC,* but apply with equal force to section 111 performance standards—including those proposed here. Indeed, in *NRDC*, the D.C. Circuit addressed the very justification EPA proffers here for promulgating the proposed affirmative defense: i.e., that such a defense is purportedly needed "to balance a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances beyond the control of the source." 79 Fed. Reg. at 1450. As the DC Circuit explained, whatever the merits of that argument in a particular case, it "does not suffice to give EPA authority to create an affirmative defense." *NRDC*, No. 10-1371, Slip Op. at 17-18.[297]

Because *NRDC* was decided after publication of the proposed NSPS, it is, of course, not discussed therein. Nevertheless, it is controlling. EPA primarily cites old cases that have been superseded by subsequent legislative and judicial developments, as the agency itself acknowledges. *See* 79 Fed. Reg. at 1450 ("[D]ue to intervening case law such as *Sierra Club v. EPA* and the CAA 1977 amendments . . . these cases are no longer good law on whether EPA can exempt malfunctions from liability . . . ."). EPA cites just two recent cases in support of the affirmative defense: *Montana Sulphur & Chemical Co. v EPA*, 666 F.3d 1174 (9th Cir. 2011) and *Luminant Generation Co. v. EPA*, 714 F.3d 841 (5th Cir. 2013). Yet *Montana Sulphur & Chemical* did not consider the lawfulness of an affirmative defense. Instead, the court referred to the existence of such a defense in upholding EPA's federal implementation plan ("FIP")-imposed numerical limitation on flaring as reasonable. *Id.* At no point did the court there hold or consider whether the defense itself was legal under the terms of the statute.

Although the 5th Circuit in *Luminant* upheld an affirmative defense provision similar to the one proposed here, *NRDC* squarely rejected, as contrary to *en banc* D.C. Circuit precedent, the premise underlying *Luminant*: that the absence of statutory language explicitly *withholding* authority to promulgate an affirmative defense by regulation should be presumed to *delegate* such authority. *Compare Luminant*, 714 F.3d at 852 *with NRDC*, No. 10-1371, Slip Op. at 17 (quoting *Rwy. Labor Execs.' Ass'n v. Nat'l Mediation Bd.*, 29 F.3d 655, 671 (D.C. Cir. 1994) (en banc)). Moreover, *Luminant* failed to consider other problems with the affirmative defense, such as the Act's explicit grant of jurisdiction to district courts—not EPA—to determine any civil penalties. *NRDC*, No. 10-1371, Slip Op. at 15-16 (citing 42 U.S.C. § 7604(a)). Thus, Joint Environmental Commenters contend that *Luminant* was wrongly decided. More importantly, this rule will be subject to review in the D.C. Circuit, not the Fifth Circuit, and thereby is governed by *NRDC*.[298]

Transp. Bd., 374 F.3d 1177, 1184 (D.C. Cir. 2004) (holding that "Board's failure to balance the competing interests . . . requires" vacatur of agency action).

[297] Indeed, the enumerated section 113(e)(1) factors include a company's "good faith efforts to comply." 42 U.S.C. § 7413(e)(1).

[298] *NRDC* did not directly opine on *Luminant* on the grounds that that case concerned the validity of an affirmative defense in a State Implementation Plan, an issue not before the *NRDC* court. *NRDC*, No. 10-

The proposed affirmative defense is also contrary to the Act for additional reasons not discussed in *NRDC*. An NSPS must remain "continuously" enforceable. By allowing plant operators to escape monetary liability during malfunctions, the affirmative defense is inconsistent with the continuous enforceability of emission limits during such periods. Although it does not bar injunctive relief, an affirmative defense to civil penalties removes a legal mechanism specified in the Act for ensuring continuous compliance, both by penalizing violations that have occurred and deterring future ones. For these reasons, the proposed affirmative defense violates the requirement that emission limitations be "continuous." It would also undermine section 304's purpose of providing for simple and straightforward enforcement, *see NRDC v. Train*, 510 F.2d 692, 724 (D.C. Cir. 1974), by requiring citizen suit purveyors to engage in fact-intensive disputes whenever a violator asserted the defense. This added burden would reduce opportunities for enforcement of the statute by citizens, impermissibly undermining the deterrent function of civil penalties and, in turn, overall compliance with the Act. *See, e.g.*, *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs.*, 528 U.S. 167, 186 (2000), S. Rep. 101-228, at 373 (1989), as reprinted in 1990 U.S.C.C.A.N. 3385, 3756.

Even if the proposed affirmative defense were consistent with the statute, it would still be arbitrary and capricious, as well as poor public policy. The defense is wholly unnecessary, even under the shorter 12-month averaging period EPA proposes. Where the standard includes a properly designed rolling annual average, as Joint Environmental Commenters have suggested herein, and the operator of the facility employs even a minimal compliance margin, the only types of violation that would fall under the affirmative defense—brief, unplanned malfunctions—would not violate the standard. In light of this, the defense is fundamentally superfluous. *See* 79 Fed. Reg. at 1450 (requesting comment on this issue). On the other hand, because the defense fails to give clear guidance to operators concerning prudent design and operational practices and instead invites dispute over these issues in any enforcement proceeding, it lessens operators' incentives to maintain reasonable compliance margins, maintain spares onsite, and take swift action to minimize emissions once a malfunction occurs. For all these reasons, operators' incentive to engage in prudent, conservative design and operations will be reduced, and emissions will increase.

In sum, the proposed affirmative defense is contrary to the Act and must not be adopted. It is also bad policy. Given the serious nature of climate change, EPA should not retract or weaken citizens' rights and remedies under the Act, as this proposal does, by making it more difficult to obtain meaningful relief when facilities are releasing unacceptably high levels of CO_2 into the atmosphere.

1371, Slip Op. at 19 n.2. Insofar as there is any import to this distinction, the section 111 standard at issue here is in all relevant respects indistinguishable from the section 112 standard. More fundamentally, the *NRDC's* reasoning is plainly contrary to the analysis provided in *Luminant*.

B. EPA Must Take Steps to Improve Near-Term Compliance.

Similarly, the proposed rule does not adequately ensure that sources will comply with the carbon pollution standards. Below, we suggest several modifications to the proposed rule that would help assure compliance. Even the shorter of the proposed rule's two averaging times—12 months—will leave the compliance status of newly constructed sources uncertain for an extended period. To ensure compliance with the NSPS, EPA should require an initial performance test before the source begins operating. In addition, two other measures can shorten the time between when the start of operations begins and when compliance with CO_2 limits is confirmed. First, although Joint Environmental Commenters recommend significant changes to EPA's proposed approach for determining applicability, to the extent an applicability threshold applies, EPA needs to factor into the initial averaging period to determine a source's compliance those operating days that predate the point at which the source crosses the applicability threshold. Second, EPA needs to reduce the unreasonably generous 180 days that the proposed rule would allow for certification of the CEMS. Finally, if EPA adopts its proposed 84-month compliance option in the final rule, the agency must include interim demonstrations to ensure compliance and should limit the option's application only to those sources that may need the additional flexibility it provides.

1. EPA Should Establish a Requirement for an Early Initial Compliance Demonstration.

EPA departs from many years of consistent practice by failing to provide for an early initial compliance demonstration for either fossil-fired steam EGUs or natural gas-fired CTs and CCGTs. Pursuant to currently applicable NSPS provisions, a new source must conduct a performance test using prescribed reference test methods within six months of startup of the unit. Thus, for example, a new CCGT must conduct an initial performance test for NO_x and SO_2 emissions within six months of startup. *See* 40 C.F.R. §§ 60.4400, 60.4415. However, in the proposed GHG NSPS, EPA eschews this standard practice without adequate explanation. As proposed by EPA, the earliest compliance demonstration for a CCGT would not occur until 19 months after the unit commences operation and, for a coal-fired steam EGU or IGCC that chooses EPA's 84-month compliance option, the first compliance demonstration would not occur until after more than seven and a half years of operation have elapsed.[299]

[299] For coal plants using CEMS and all gas plants, the rules require installation and certification of the monitoring system within 180 days of commencing commercial operations. *See* 40 C.F.R. § 75.4(b)(2); *see also* 79 Fed. Reg. at 1450 (citing section 75.4(b)'s 180-day window). Sources would then spend either 12 or 84 months collecting their first sets of data. Finally, plants would conduct an initial compliance determination within 30 days of the end of that first compliance period. *See Id.* at 1503 (proposed 40 C.F.R. § § 60.46Da(e)), 1508-09 (proposed 40 C.F.R. § 60.4376(b)(1)) (this provision would actually require an initial compliance report to be submitted within 30 days of the end of the calendar quarter that includes the 12th month of data collection). Adding these figures up, it becomes apparent that the earliest initial compliance test would occur 19 months after the start of commercial operations for gas plants, and 91 months for coal plants following the 84-month compliance period.

An initial performance test is needed for all sources covered by these NSPS. Although EPA has not proposed such a requirement, the agency has sought comment on whether it should impose a performance test requirement on new stationary combustion turbines. *See* 79 Fed. Reg. at 1497. In fact, performance testing is needed for *all* regulated sources to ensure they are capable of achieving in practice their designed efficiency levels. Failure to require performance testing at the outset of operations would be inconsistent with the command in section 111(b)(1)(B) that a standard of performance or revision thereto "shall become effective upon promulgation," and in section 111(e) that "[a]fter the effective date of standards of performance … it shall be unlawful for any owner or operator of any new source to operate such source in violation of any standard of performance applicable to such source."

The need for early determinations of compliance is especially great in light of the long averaging times EPA has proposed. As the agency notes in the preamble, "[r]equiring an initial compliance test that is numerically more stringent than the annual standard for new combined cycle facilities would insure that the most efficient stationary combustion turbines are installed." *Id.* Indeed, EPA's own guidance recognizes that such testing "is an important tool used to determine a facility's compliance with emission limits."[300] A number of the commenting organizations have elsewhere recommended stringent "new and clean" limits, adjusted to standard environmental and operating conditions in order to address industry concerns about in-use variability and performance degradation while still ensuring that the most efficient designs are used.[301] But even if EPA fails to adopt a separate "new and clean" limit, there is no reason not to require that sources demonstrate their ability to perform to the annual average emission limits when the unit is new and under controlled conditions.

Similarly, for sources relying on the 84-month compliance alternative, it is essential to demonstrate the ability to meet the applicable emission limits. Among other things, a coal-fired source using CCS and adopting the 84-month compliance alternative would need to provide sufficient documentation to demonstrate at startup that the CO_2 capture system functions properly and that it will be able to sequester CO_2 on-site at a properly permitted facility that reports its CO_2 under 40 C.F.R. Part 78, subpart RR, or assure long-term containment through transfer to an offsite facility that reports its CO_2 under 40 C.F.R. Part 78, subpart RR.

Where the sequestration operations are under common ownership or control, there would seem to be no reason why such testing could not be conducted as normally required in NSPS. We recognize that plants that are not co-located with their CO_2 sequestration operations and that do not have ownership (and thus control) over those operations may face unique

[300] EPA, *Issuance of the Clean Air Act National Stack Testing Guidance* (Apr. 27, 2009) at 1, *available at* http://www.epa.gov/compliance/resources/policies/monitoring/caa/stacktesting.pdf, attached as **Ex. 121.**

[301] *See, e.g.*, Sierra Club and NRDC, *Comments on Washington's Proposed Emissions Performance Standard Update* (Dec. 3, 2012), *available at* http://www.commerce.wa.gov/Documents/SierraClub-Nat-lResource-Def-12-3-12.pdf, attached as **Ex. 122**; *see also* Sierra Club *et al.*, *supra* n. 200., at 45-46.

challenges in conducting an initial performance test of the injection or sequestration activity[302] (where it is not already operating). However, even in these circumstances, an initial performance test of the generating unit and its CO_2 capture equipment would still provide valuable information on the source's ability to meet the NSPS. A performance test that demonstrates insufficient CO_2 capture capacity or combustion efficiency that is below levels needed to meet the NSPS will avoid what otherwise could amount to many years of excess and unlawful CO_2 emissions.

Although we do not offer detailed comments here on the timing or conditions of initial performance tests, the agency's guidance makes clear that those conditions should generally be rigorous. EPA's guidance specifically provides that testing should be conducted under conditions that reflect real-world operations and that are likely to "most challenge" the performance of emission control measures.[303] Consistent with this guidance, initial performance testing should be conducted using the most carbon-intensive fuels permitted at the source and with the source operating at load levels, including part-load operation, that reflect what the agency calls "realistic worst case conditions."

Failure to require an early initial compliance demonstration not only risks facilitating a lengthy period of noncompliance, it may create a situation where the "equities on the ground" make effective injunctive relief less probable. The delay in establishing the performance of the unit may also make it difficult, if not impossible, to resolve issues as to the division of responsibility for any problems between the vendor and the operator. For these reasons, and those discussed above, EPA must require early initial performance tests for all regulated units, in keeping with its standard best practices and sound public policy.

2. Ignoring Emissions that Predate the Applicability Threshold Is Unwarranted.

In part to exempt peaking power plants from the proposed standards, EPA has proposed limiting the applicability of the standards to plants that sell in excess of one-third of their potential electric output and 219,000 MWh to the grid annually.[304] *See* 79 Fed. Reg. at 1459. One impact of the extended averaging period for the applicability determination is a significant delay in the date by which certain sources must comply with the proposed standards. The proposed rule states that, for sources subject to standards with a 12-month averaging period, the "initial 12-operating month compliance period would begin with the first month of the first calendar year of EGU operation in which the facility exceeds the capacity factor applicability

[302] For CO_2 transfer to a sequestration facility that is already in use, no such initial performance testing may be necessary. In that case, an examination of monitoring and reporting records for the facility may suffice. Joint Environmental Commenters suggest that documentation of the facility's permits and most recent report should be included with the compliance materials.
[303] *Id.* at 15.
[304] Under the subpart Da, this determination is made annually. 79 Fed. Reg. at 1502 (proposed 40 C.F.R. § 60.46Da(a)(2)). Under subparts KKKK and TTTT, it is made on a three-year rolling average basis. 79 Fed. Reg. at 1506 (proposed 40 C.F.R. § 60.4305(c)(5)), 1511 (proposed 40 C.F.R. § 60.5509(a)(1)-(2)).

threshold." *Id.* at 1451. For a source that exceeds the applicability threshold in January, this language appears to allow the source to ignore all emissions prior to that month, with the source's first 12-month compliance period concluding in December of that year. In sum, the proposed rule would not require a compliance determination until up to 12 months after the applicability threshold is crossed.

This problem illustrates one of the many reasons why Joint Environmental Commenters oppose the proposed capacity factor-based threshold. But in the event EPA keeps the threshold, there is no reason to wait up to a full year after applicability is triggered to make the first compliance determination. Even sources that are intended to run at high capacity factors may not sell enough electric output to the grid to cross the proposed applicability threshold for well over a year. For these sources, the proposed delay of the beginning of the first compliance period serves no policy-grounded purpose—it merely delays the date by which those sources must demonstrate compliance with the NSPS. The initial compliance dates should reflect that most plant operators will know the ultimate applicability status of their sources well in advance of crossing the applicability threshold. Therefore, the initial compliance determination should be made at the end of the month during which a source crosses the applicability threshold (or at the end of the source's twelfth month of operation, if that has not yet occurred), not up to a full year later.

Including in a compliance determination emissions that predate the point at which a source crosses the applicability threshold is consistent with Congress's timing scheme for applying NSPS to new sources. The CAA defines a "new source" for the purposes of section 111 as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." 42 U.S.C. § 7411(a)(2). This unique use of the date of *proposed* regulations to define the sources to which an NSPS applies shows that Congress meant to require compliance by new sources without delay. EPA should therefore not base applicability determinations on a source's actual generation. If EPA chooses to adopt its proposed applicability test it should require the initial compliance determination in the first month after a source crosses the applicability threshold.

3. Allowing 180 days to Certify CEMS is Unreasonable and Unnecessary.

EPA's proposed rule would follow the Part 75 approach of allowing sources 180 days to certify the performance of their CO_2 monitoring equipment. *See* 79 Fed. Reg. 1451 ("In accordance with § 75.64(a), the proposed rule would require an EGU owner or operator to begin reporting emissions data when monitoring system certification is completed or when the 180-day window in § 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier)."). However, simply applying the 180-day window from the Part 75 regulations ignores that the justification behind this allowance in the currently existing regulations is not applicable here. The timetable in 40 C.F.R. § 75.4, which dates from the time the acid rain program was implemented nationwide, primarily governs the more difficult task of retrofitting monitoring equipment onto existing sources. *See*, *e.g.*, 60 Fed. Reg. 26,510, 26,511

(May 17, 1995) (imposing the 180-day timetable as a technical correction to address CEMS implementation issues). There is no basis for finding that new sources face similar challenges in installing monitoring equipment during initial plant design and construction. A 90-day period would be consistent with the timetable EPA initially promulgated for the certification of CO_2 CEMS, *see* 58 Fed. Reg. 15,634, 15,717 (Mar. 23, 1993), and would reflect the time reasonably necessary to conduct the required procedures.[305]

4. An 84-Month Compliance Option Must Include Additional Measures to Ensure Compliance.

If included in the final standards, an 84-month compliance option must be structured with additional features necessary to ensure compliance. As set out in more detail in the comments of several of the Joint Environmental Commenters on the 30 year compliance alternative included in EPA's 2012 proposal, averaging periods that extend over many years must be accompanied by measures to reduce the possibility of widespread non-compliance undermining the achievement of the long-term emission reduction goals.[306] To ensure the integrity of the proposed standards and to meet EPA's other obligations under the CAA, EPA must require milestones to ensure that regulated sources take all necessary steps to prepare for, and operate under, the 84-month emission limitation period.

The most straightforward and effective way of ensuring that sources meet their 84-month compliance obligation is to require that the operator demonstrate at the end of each 12-operating month period that the source will meet the requirement in accordance with the established averaging period and realistic operating assumptions. The permitting authority would be required to approve the certification and demonstration of compliance; regulators and the public could bring an enforcement action if the demonstration was not sufficient to establish compliance with the NSPS. Adopting these steps will help to provide certainty both to regulators and regulated sources, and will avoid situations where sources find themselves ultimately unable to achieve sufficient emission reductions to make up for excess emissions during the initial months of operations.

EPA has sought comment on the possibility of supplementing the 84-month standard with interim requirements, recognizing that such an approach will "facilitate enforceability and assure adequate emission reductions." 79 Fed. Reg. at 1448. In selecting the appropriate

[305] *See* Emerson Process Management, Certification Testing vs. Compliance Testing for CEMS, Technical Guide No. 51A-TG-103-101C (Jan. 2011) at 2, *available at* http://www2.emersonprocess.com/siteadmincenter/PM Rosemount Analytical Documents/PGA_ADS_Certificate_Testing_vs_Compliance_Testing.pdf (recommending that "a full week should be planned for start up of the CEMS" and that "a month should be allocated" for CEMS operation, "during which time the CEMS should successfully complete the equivalent of a seven day drift test," which the CEMS "usually passes . . . the first week after start-up").

[306] *See*, *e.g.*, Sierra Club *et al.*, *supra* n. 200 at 70) (discussing problems with the South Coast Air Quality Management District's Regional Clean Air Incentives Market (RECLAIM) program).

interim requirements, EPA must keep in mind its rationale for the 84-month compliance option. The proposed rule states that this extended averaging period "will tend to compensate for short-term emission excursions, which may especially occur at the initial startup of the facility and the CCS system." *Id.* at 1482. The 84-month compliance option therefore recognizes that some sources may emit CO_2 at a rate that exceeds the 84-month standard level during at least some portion of their initial years of operation. For these sources, the key question to answer in an interim analysis is whether they retain the capability to comply with the 84-month limit given the time that remains in the compliance period. That answer depends on three pieces of information: (1) the plant's current cumulative CO_2 emission rate; (2) the capacity of the plant's CO_2 capture and sequestration equipment—the minimum design emission rate of the source—as demonstrated during initial performance testing;[307] and (3) an assumed level of MWh output for the years of operation that remain in the compliance period.

Joint Environmental Commenters suggest a simple three-step process that would enable permitting authorities to annually evaluate the source's ability to meet the 84-month limit.

- **Step 1 – Determine the projected 84-month MWh output of the source.** For each of the remaining years in the averaging period, project the amount of net output generation that will occur based on the net output of the unit (assuming a standard capacity factor, e.g., 85 percent) with and without operation of the CCS system and the projected utilization of the CCS system. The resulting projected annual MWh output would then be added to the source's cumulative MWh output to date to determine the projected 84-month electric generation output of the source.

- **Step 2 – Determine the minimum practicable 84-month CO_2 emissions for the source.** For each of the remaining years in the averaging period, project the amount of CO_2 emissions that will occur based on the demonstrated CO_2/MWh(net) emission rate of the unit with and without operation of the CCS system and the projected utilization of the CCS system. The resulting annual CO_2 emissions would then be added to the source's current cumulative CO_2 emissions, and the result represents the projected amount of CO_2 that the source would be expected to emit over the entire 84-month period.

- **Step 3 – Calculate the source's minimum practicable 84-month CO_2 emission rate.** Divide the source's projected 84-month CO_2 emissions by the source's projected 84-month MWh output to obtain the minimum practicable 84-month emission rate for the source.

[307] As recognized above in our comments on the need for initial compliance demonstration requirements, for certain coal-fired sources, initial performance test data may be available only for the generating unit and its CO_2 capture equipment. In such circumstances, the capacity of the infrastructure enabling long-term containment of the source's CO_2 must reflect documentation provided by the source.

If the minimum practicable 84-month emission rate that the source can achieve, based on its performance to date and the capabilities of its capture and sequestration equipment, exceeds the applicable standard, then the source is in violation and must cease operating until it is able to come into compliance by reducing its minimum practicable 84-month CO_2 emission rate below the level of the standard.

For example, a source that otherwise operates as normal but does not successfully sequester any of its CO_2 output during its first two 12-operating-month periods would likely not be in violation if it has installed CO_2 capture equipment that can achieve an emission rate that is 50 percent lower than the applicable 84-month emission rate, and has secured access to sequestration facilities and equipment that also has twice the capacity needed to meet the 84-month emission rate. The source could still feasibly meet the 84-month standard. But if the same source still has not begun capturing and sequestering CO_2 by the end of its 48th operating month, it would likely be in violation of the NSPS limit.

Regardless of what interim requirements are adopted, EPA must ensure that information on the progress of sources subject to the 84-month compliance option is available. The proposed rule would not require sources that have selected this option to submit compliance data to EPA until the end of the 84-month compliance period. *See* 79 Fed. Reg. at 1452 ("The first report would be for the quarter that includes the final (60th) [sic] operating month of the initial 84-operating-month compliance period."). Access to up-to-date emission rate information is important to citizens concerned about the health and environmental impacts of CO_2 emissions from power plants. Such information is also crucial for EPA to fulfill its obligation to consider "emission limitations and percent reductions . . . achieved in practice" when reviewing and revising the NSPS. 42 U.S.C. § 7411(b)(1)(B). Deferring sources' reporting obligations for seven years would leave EPA unprepared to gather necessary emission rate data when these standards next come up for review and would also impede the agency's development of NSPS for other source categories for which CCS may be appropriate.

EPA must further adopt regulations ensuring that sources are equipped to meet the 84-month standard. Such rules need to include specific deadlines and required filings with the permitting agency to ensure that all CCS-related components, including not only carbon capture equipment but also all necessary infrastructure and sequestration agreements are in place at the time the source begins operating, along with any other components needed to comply with the 84-month emission limitation. Such measures must be incorporated into sources' Title V permits as conditions of operation. This will ensure that they are binding and enforceable.

Additionally, because EPA has proposed the 84-month compliance option to accommodate difficulties that may be experienced during a source's initial startup period, the agency should clarify in the final rule that this option is available only during a source's initial 84 months of operation after construction. Thereafter, EPA's rationale for the extended compliance period no longer applies, and the flexibility provided by the 84-month option is no longer warranted. After their initial 84 operating months, all sources should be subject to the 12-operating month standard.

Finally, as EPA proposed in 2012 for the 30-year compliance option then under consideration, the 84-month option should automatically terminate for new plants commencing construction eight years or more after the proposed rule—that is, in 2021. As EPA observed in the 2012 proposal, the flexibility afforded by a compliance option with an extended averaging period "is likely to be most important for the first several CCS projects (i.e., 'first movers')," 77 Fed. Reg. at 22,407, and should not be necessary by the time the NSPS is next reviewed. Automatic termination of the provision will also prevent unwarranted expectations that the option will be renewed, while not precluding EPA from renewing the provision if it is still determined to be appropriate in 2021.

C. EPA Must Ensure That Penalties Are Sufficient to Deter Violations.

Given the very large economic benefits that may accrue from the unlawful operation of highly profitable plants, EPA must make the most of its ability to deter violations through penalties.[308] Two provisions of the Clean Air Act authorize penalties for NSPS violations. Section 113(d)(1) provides for civil penalties of up to $37,500 "per day of violation." 42 U.S.C. § 7413(d)(1)(B); 40 C.F.R. Part 19 (adjusting $25,000 maximum daily penalty for inflation). This equates to a maximum penalty of $13,687,500 per year. However, to ensure the availability of penalties that exceed the economic benefit of the violation, section 120 separately authorizes noncompliance penalties that are set at the amount of economic benefit gained from noncompliance. 42 U.S.C. § 7420(d)(2).[309] These noncompliance penalties are in addition to, and not in lieu of, the civil penalties described in Section 113(d)(1). *Id.* § 7420(f).[310]

Recognizing the potential for disputes over the duration of violations that are calculated against a long averaging period, the proposed rule seeks comment on a method for determining the number of daily violations within the proposed averaging periods. Under this approach, the number of violations in any 12- or 84-operating month period in which the source's average emission rate exceeds the standard would be the number of operating days in that period. *See* 79 Fed. Reg. at 1498. However, violations that persist or recur would not result in a second penalty being assessed for an operating day penalized as part of a prior violation. *See id.*

The long averaging periods EPA has proposed raise serious concerns regarding penalties

[308] Assuming a wholesale electricity price of $40/MWh, a 400 MW unit operating at an 85 percent capacity factor would generate $120 million per year in revenues.

[309] *See* S. Rpt. 95-127 at 49 (observing that "many sources continue to find the fees paid to attorneys to resist the requirements of law less expensive than pollution control equipment" and stating that section 120 penalties will "balance the economic difference between those who comply and those who resist or delay").

[310] The hypothetical plant discussed in footnote 308 above could cover the costs of a full year's worth of CO_2 emission limit violations under section 113(d)(1) (365 daily violations X $37,500 per violation = $13,678,500) at a cost of less than $5 per MWh ($13,678,500/year in penalties ÷ (400 MW x 8 8760 hours/year x .85 capacity factor) = $4.59/MWh).

and enforcement, and we appreciate EPA's effort to address these issues now, rather than await individual enforcement actions. For the reasons discussed below, we recommend that compliance determinations be made daily and that EPA clarify how penalties would be calculated for sources that do not meet the 95 percent valid data requirement.

1. Compliance Determinations Should Be Made Daily.

EPA should require daily, rather than monthly, calculation of a source's rolling annual average CO_2 emissions. If a daily calculation is required, once a facility determines that it is in violation of the annual or seven-year standard (depending upon which standard applies to that source), each subsequent operating day on which the rolling average continues to exceed the standard would count as another day of violation for purpose of calculating penalties. This approach reflects that the CAA's penalty provisions aim to remedy *all* excess emissions—each "day of violation," not merely those days on which the compliance calculation happens to fall. Moreover, once a facility is in violation of the standards, penalizing each additional day spent operating in excess of the applicable CO_2 limit will better ensure that the source comes into compliance as soon as possible, rather than gradually over the course of the 13^{th} (or 85^{th}) month. Finally, because source operators must know each day's emissions in order to manage their compliance obligations, the rolling average is likely to be calculated each day even if only monthly data is submitted to EPA. This level of vigilance is especially likely for sources in violation of the standards, or close to violating them. Therefore, this change would likely impose little additional burden on facility operators.

EPA's rationale for the proposed monthly calculation requirement appears to be that it will limit the amount of data that states and EPA will need to audit. *See* 79 Fed. Reg. at 1452/2. However, a daily computation by the source poses no additional burden on permitting authorities, since those authorities will have to review hourly and daily emission data in order to properly audit the monthly averages. EPA's argument also ignores the fact that, with only a few exceptions, the utility industry is already required to monitor and electronically report *hourly* CO_2 emissions data under Part 75. *See* 40 C.F.R. § 75.64(a)(6).[311] Moreover, if the data is reported electronically, as EPA has proposed, initial audits of the compliance data can be done via software applications, which can just as easily track daily computations as monthly calculations.[312]

[311] *See also* EPA, *Plain English Guide to the Part 75 Rule* (June 2009) at 17, *available at* http://www.epa.gov/airmarkets/emissions/docs/plain_english_guide_par75_final_rule.pdf (stating that the data and information to be reported include the facility's hourly emissions data), attached as **Ex. 123**.

[312] *See id.* at 88 ("When emissions data are reported in a standardized electronic format such as XML, regulatory agencies can develop software tools with which to audit the data. The results of these electronic audits can serve as a basis for targeting problem sources, either for more comprehensive electronic audits or for field audits.").

2. **EPA Should Clarify How Penalties Would Be Assessed Against Sources That Do Not Meet the Required 95 Percent Valid Data Threshold.**

The proposed regulations would require sources to demonstrate compliance with the CO_2 emissions standard by using only operating hours during which valid data have been gathered for all the relevant parameters. *See* 79 Fed. Reg. at 1504 (Proposed 40 C.F.R. § 60.46Da(g)(1)(i)), 1507-08 (Proposed 40 C.F.R. § 60.4374(a)(1)), 1513 (Proposed 40 C.F.R. § 60.5540(a)(1)). The proposal further provides that the source must obtain valid hourly values for a minimum of 95 percent of the operating hours in the applicable compliance period. *Id.* Because it provides an important incentive to generate accurate data essential to ensuring meaningful compliance with the proposed standards, Joint Environmental Commenters support the proposed 95 percent requirement.

However, EPA should specify that a source's failure to meet the 95 percent data requirement represents a violation of the rule's monitoring requirements, and should clarify the agency's approach to assessing penalties for such a failure. One possibility would be to assess penalties based on the number of individual operating days in which the 95 percent data requirement was not met. For example, if the source operated for all 24 hours on a particular operating day, but only had 22 hours of valid data (representing 91.2 percent data validity), the day would be counted as a day of violation for the purpose of calculating penalties. But if the source had 23 hours of valid data for the day (representing 95.8 percent data validity), there would be no penalty assessed for that day. Another option would be to assess penalties based on a percentage of the source's annual operating days equivalent to the percentage of operating hours for which the source lacks valid data. For example, if a source operated on 200 days over a 12-month period and lacked valid data for 10 percent of its operating hours, it would be in violation for 20 days over the period.

D. EPA Should Require Direct CEM Monitoring of CO_2 Emissions.

EPA proposes to facilities that burn only liquid- or gas-based fuel to determine compliance either by using CEMS or by estimating emissions based on their fuel consumption. 79 Fed. Reg. at 1501 (Proposed 40 C.F.R. § 60.46Da(f)(3)), 1507 (Proposed 40 C.F.R. § 60.4373), 1512-14 (Proposed 40 C.F.R. §§ 60.5535, 60.5540).[313] Direct monitoring of emissions, especially using CEMS, is generally more accurate than estimating emissions using fuel consumption, as EPA has previously acknowledged.[314] Accordingly, EPA should require CEMS for emissions from all units, regardless of fuel type.

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[313] It appears that EPA inadvertently omitted a third provision relating to the use of fuel consumption to estimate emissions. Proposed 40 C.F.R. § 60.5535(c) refers the option of "determin[ing] . . . CO_2 mass emissions . . . by monitoring fuel combusted in the affected EGU and periodic fuel sampling *as allowed under § 60.5525(c)(2)*," but the proposal does not contain a section 60.5525(c)(2).

[314] *See, e.g.*, EPA, Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Proposed Rule (Mar. 2009) at 5-15—5-21 (Mar. 2009), attached as **Ex. 124**; Schakenbach, Vollaro, & Forte, U.S. Office of Atmospheric Programs, *Fundamentals of Successful Monitoring, Reporting, and*

EPA's fuel sampling procedures for natural gas include a determination of the relationship between fuel flow and load for the unit.[315] In doing so, the operator measures the fuel consumption and generation of the unit on an hourly basis for 168 hours and determines the average fuel consumption per unit of generation. However, EPA's procedure allows a source to exclude as "nonrepresentative" any hour in which the unit is "ramping up or down" (defined as a variation in load of greater than 15 percent) or is operating at low-load (defined as any hour in which the load is in the lower 25 percent of the unit's normal range of operation). This procedure effectively exempts periods of low or changing load from regulation. As recognized by EPA in its earlier proposal, emission rates are ordinarily higher during these periods of operation than during steady-state, near-full load conditions. Since the excess CO_2 generated under these conditions contributes to climate change and can be reduced by minimizing low-load and ramping activities, if EPA includes in its final rule a monitoring option based on fuel consumption, these emissions should not be excluded from the emissions calculations. Additionally, the best CCGT designs provide for a broader range of efficient operation than poorer designs, a fact that should be recognized in the determination of BSER and in the compliance obligations of the rule.

Joint Environmental Commenters further note that the information used to set the standards for new gas turbines is largely CEMS data, which does not exclude periods of ramping activities and low load. Similarly, the proposed emission limitation applicable to steam EGUs does not rely on a fuel sampling procedure that excludes these modes of operation from consideration. Therefore, allowing sources to disregard these modes of operation from a compliance demonstration would arbitrarily weaken the standard below levels reflecting BSER. Such an approach would also violate the requirement that sources demonstrate continuous compliance with the performance standards. EPA should therefore require all new plants to use CEMS to calculate CO_2 emissions, but should require plants to include periods of ramping and low load in there compliance determinations for any monitoring methods that are permitted in the final rule.

E. EPA Should Strengthen the Record Retention Requirements.

EPA's proposed rule would require sources to retain compliance records on site for only two years, after which records could be retained "off-site and electronically." 79 Fed. Reg. at 1505 (Proposed 40 C.F.R. § 60.46Da(i)(8)), 1509 (Proposed 40 C.F.R. §60.4391(h)(3)), 1515 (Proposed 40 C.F.R. § 60.5565(c)). The effect of this seemingly innocuous provision is to reduce the efficacy of onsite inspections and make compliance determinations only possible through information requests authorized under section 114 of the CAA and analogous state provisions (where they exist). Section 114 information requests by EPA's enforcement office have often

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Verification under a Cap-and-Trade Program ('*Fundamentals*'), 56 J. of the Air & Waste Mgmt. Ass'n 1576, 1581 (Nov. 2006), attached as **Ex. 125**.

[315] Alternatively, a source operator may calculate the unit's gross heat rate, but may still exclude ramping and low load operation. 40 C.F.R. Pt. 75, Appendix D 2.1.7.

been the subject of controversy, as well as attempted interference by Congress.[316] State and local officials are particularly reliant on onsite inspections to ensure regulatory compliance. If they have the authority to conduct document-intensive offsite investigations, they use it only rarely. The prospect of essential information being stored at a remote location, which may lie outside the jurisdiction of the state or local authority, and in formats that may be difficult to access, presents a significant obstacle to enforcement in the current era of shrinking EPA and state agency enforcement budgets.[317] EPA has not identified any particular (or even generalized) basis for its proposal to permit offsite storage after two years. Technological advances have reached the point where a year's worth of data, including scanned PDF documents, can be stored on a single flash drive, negating earlier arguments about space requirements.

To facilitate the expeditious review of needed information, EPA should adopt additional requirements covering record retention. For example, under the subpart 98 reporting program for GHGs, records may be stored off site only "if the records are readily available for expeditious inspection and review." 40 C.F.R. § 98.3(g). In addition, for any records stored electronically, "the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents." *Id.* To properly implement the CAA's citizen suit provisions, EPA should clarify that "readily available" means available on demand, not just to EPA, but to state and local authorities, irrespective of jurisdiction over the site where the records are stored, and to the general public. Because these requirements apply to CO_2 emissions data from power plants under the GHG reporting program, extending their application to the proposed NSPS will ensure consistent requirements and will impose little, if any, additional burden. *See id.* § 98.47.

XII. The NSPS Must Cover Sources in Development that Have Not Yet Begun Construction

The Clean Air Act provides that an NSPS applies to all sources in the regulated category that commence construction after the standard is first proposed. *See* 42 U.S.C. § 7411(a)(2). In its 2012 proposal, however, EPA proposed to exempt new sources that had a valid PSD permit and were poised to begin construction, so long as they commenced construction within one year of the proposal's publication. EPA termed this exempt class of facilities "transitional sources." Joint Environmental Commenters objected that nearly all of the transitional sources were unlikely to proceed with construction, and that, in any event, EPA's proposal to exempt

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[316] EPA's Office of Air and Radiation has also demonstrated a reluctance to apply to the Office of Management and Budget for permission under the Paperwork Reduction Act to employ section 114 requests to obtain information needed for rulemaking development.

[317] EPA's draft Fiscal Year (FY) 2014–2018 Strategic Plan announced significant and troubling cuts to the agency's enforcement program, including reductions in in-person inspections and civil cases. *See* EPA, *Draft FY 2014–2018 EPA Strategic Plan* (Nov. 19, 2013) at 82, *available at* http://progressivereform.org/articles/EPA_Draft_Strategic_Plan112013.pdf**,** attached as **Ex. 126.**

them was inconsistent with the CAA's definition of "new source" and the requirements of Section 111.[318]

Today, most of the so-called "transitional sources" that could not meet the 1,100 lb CO_2/MWh performance standard have indeed announced cancelation or have converted to natural gas projects. At the time EPA's current proposal was made public in draft form in September 2013, four units were still purportedly under development as coal-fired power plants: Wolverine (MI), Washington County (GA) (also known as "Plant Washington"), Holcomb (KS), and Two Elk (WY). Wolverine announced its cancelation on December 17, 2013.[319]

EPA's 2014 proposal includes a TSD that discusses the remaining three sources purportedly under development, but there is considerable uncertainty in EPA's approach to these sources.[320] EPA repeatedly notes that these sources' developers have represented to the agency that they have already commenced construction on the projects. *See, e.g.*, 79 Fed. Reg. at 1461 ("Based solely on the developers' representations, the projects would be existing sources, and thus not subject to this proposal.").[321] But EPA also repeatedly emphasizes that it has not evaluated or accepted the developers' claims, acknowledges the substantial contrary evidence submitted by several of the Joint Environmental Commenters and others,[322] and explicitly reserves the right to determine at a later date that these sources in fact did not commence construction before the NSPS was proposed. *See* 79 Fed. Reg. at 1461.

If EPA determines that Plant Washington or Holcomb have not already commenced construction, EPA "anticipate[s] proposing at a later time that [Plant Washington and Holcomb] *either* be made subject to the 1,100 lb CO_2/MWh *or* be assigned to a subcategory with an alternate CO_2 standard."[323] As for Two Elk, if EPA later determines that construction has not been continuously underway, the agency proposes to require it to meet the NSPS.[324]

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[318] "The term 'new source' means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." 42 U.S.C. § 7411(a)(2).

[319] Lamb, *Wolverine Power makes it official 'project will cease'*, Presque Isle Advance (Dec. 17, 2013), *available at* http://demo.piadvance.com/2013/12/wolverine-makes-it-official-project-will-cease/, attached as **Ex. 127.**

[320] *See* EPA*, Fossil Fuel-Fired Boiler and IGCC EGU Projects under Development: Status and Approach*, Technical Support Document for the EGU NSPS Proposed Rule, EPA-HQ-OAR-2013-0495-0024 (hereinafter "PUD TSD"), *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0024 , attached as **Ex. 128**.

[321] *Id.* at 9 (discussing Plant Washington), 10 (discussing Holcomb), 11 (discussing Two Elk).

[322] *See* Sierra Club *et al.,* supra n. 200, at 75-77, 78, and accompanying exhibits, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-10798. (Note: while the relevant exhibits are available at the aforementioned address, the finalized comments are available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-10887.)

[323] PUD TSD at 8. EPA specifically describes this approach only for the Wolverine plant, but states that "if it is determined in the future that either [Holcomb or Plant Washington] has not commenced

Joint Environmental Commenters support EPA's decision to discard the "transitional source" classification, to abandon its approach of using "sunk costs" to determine BSER for these sources, and to apply the proposed standard to plants that are designed to meet it, such as the Texas Clean Energy Project. We also support EPA's apparent intent to determine (either in this rulemaking or "at a later time") whether Plant Washington, Holcomb, and Two Elk did indeed "commence construction" prior to the date of the proposed NSPS. As we discuss below, the record does not contain evidence to corroborate the developers' claims that these sources have commenced construction, and EPA may not take the developers' unsupported and self-serving claims at face value. Moreover, substantial contrary evidence demonstrates that each of these sources have not yet commenced construction and are not on the verge of doing so. Based on the administrative record for this rulemaking, EPA cannot at this time validly conclude that these sources have commenced construction.

Additionally, as several of the Joint Environmental Commenters explained in their 2012 comments, there is no legal justification for creating a separate subcategory with a different CO_2 emissions standard based solely on the stage of a source's development. We urge EPA to finalize its proposed option to make all new sources subject to the 1,100 lb CO_2/MWh standard regardless of their stage of development, rather than fashion a separate, plant-specific standard for certain individual sources. Once EPA determines that Plant Washington and Holcomb have not yet commenced construction, it should require these new facilities to comply with the same performance standard that applies to all other new sources in this category.

A. Plant Washington, Holcomb, and Two Elk are Not Existing Sources.

EPA's rules implementing the Clean Air Act define the actions that constitute "commencement of construction" for NSPS purposes. *See* 40 C.F.R. § 60.2. Specifically, these rules define "construction" as the "fabrication, erection, or installation of an affected facility," and define "commenced" to mean that "an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification." *Id.*

The record for this rulemaking does not contain evidence that would allow EPA to conclude that Plant Washington, Holcomb, or Two Elk have commenced construction under this

construction as of the date of this proposal, then that project will be addressed in the same manner as the Wolverine project." 79 Fed. Reg. at 1461. EPA does not include Two Elk in this category due to the "long-standing nature of the developer's position that the project commenced construction in 2005." PUD TSD at 11. However, the agency correctly states that if Two Elk's permit has lapsed due to insufficient construction activity, "it should be treated like any other new source if the developer were to resume development efforts." *Id.* at 11.

[324] *Id.* at 11.

definition. There is no evidence that either Plant Washington or Holcomb have actually begun physical, on-site construction, nor is there adequate evidence that either has either entered into the requisite contracts. Two Elk, on the other hand, has a permit that has now lapsed due to lack of construction activity for many years. Moreover, significant evidence shows that none of these three sources is poised to begin construction at any time in the near future. Accordingly, EPA may not determine in this rulemaking that any of these three proposed facilities are existing sources.

1. Plant Washington[325]

Power4Georgians ("P4G") contends that it has commenced construction of Plant Washington, such that the facility is an existing source that should be exempted from EPA's proposed NSPS for new coal-fired EGUs. It is undisputed that P4G has not commenced *physical* construction of Plant Washington. Instead, P4G claims that it has entered into contracts to supply and erect the facility's boiler and, on that basis, EPA should deem the plant an existing source for NSPS purposes.

Contrary to P4G's self-serving representations, there is neither legal nor factual support in the record for its claims. First, the language and purpose of section 111 (as well as EPA's prior practice) confirm that EPA's April 13, 2012 publication date of the original NSPA proposal set the benchmark date for new sources. There is no question that at that time, Plant Washington did not have a final, valid air permit that authorized construction of the plant, nor had it commenced construction for NSPS purposes. Thus, if built, Plant Washington should be subject to the NSPS for new coal-fired EGUs.

Second, as EPA acknowledges, the record does not support P4G's claims that it has commenced construction of Plant Washington even under the January 8, 2014 publication date of the re-proposal. Without adequate support in the record, EPA cannot conclude that Plant Washington has commenced construction or deem it an existing source. On the contrary, the available facts show that Plant Washington has *not* commenced construction, nor is it is not on the verge of doing so, and thus the record does not support P4G's claims that Plant Washington is an existing source.

a. Plant Washington Is a New Source Under EPA's Initial Proposal Published on April 13, 2012.

EPA should continue to use the original proposal date of April 13, 2012 as the benchmark for distinguishing new sources from existing sources (known as the "applicability

[325] One of the Joint Environmental Commenters, Southern Environmental Law Center, will be submitting a separate set of comments regarding Plant Washington. Those comments will include all of the documents cited herein relating to Plant Washington. Because those materials will be made part of the administrative record through that submission, we include them in our citations but do not include them as attachments here.

date"). As explained below, April 13, 2012 is the proper applicability date under the Clean Air Act, applicable EPA regulations, judicial interpretations, and the agency's own past practices. There is no dispute that Plant Washington had not commenced construction by April 13, 2012. Thus, it should not be considered an existing source.

i. April 13, 2012 Is the Proper Applicability Date Under the Clean Air Act and Its Implementing Regulations.

The plain language of the Clean Air Act demonstrates that the appropriate applicability date is the date EPA initially proposes a standard, even if the agency later modifies or re-proposes that standard. The statute defines a new source as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." 42 U.S.C. § 7411(a)(2). Once EPA proposes a standard, the applicability date is set, and does not change even if the standard is subsequently altered: "[o]nce [a facility becomes] a new source, it remain[s] a new source regardless of what happen[s] to the [proposed] standard." *United States v. City of Painesville, Ohio*, 644 F.2d 1186, 1189 (6th Cir. 1981). In enacting section 111, Congress provided that "the publication of proposed regulations establishes the cut-off date for identifying new sources," even though a "proposed regulation is, of course, subject to both administrative and judicial review and, consequently, modification." *Id.*; *accord Com. of Pa., Dep't of Envtl. Res. v. EPA*, 618 F.2d 991, 999 (3d Cir. 1980) ("[T]he proposal of new source standards [under the Clean Water Act] puts the world on notice, and . . . the regulations, whenever promulgated, apply to all who have been put on notice.").

Regulations implementing the CAA confirm that a facility is subject to an NSPS if it commences construction or modification after the date of publication of "*any* proposed standard" applicable to that facility. 40 C.F.R. § 60.1(a) (emphasis added).[326] Courts "have recognized on many occasions that the word 'any' is a powerful and broad word, and that it does not mean 'some' or 'all but a few,' but instead means 'all.'" *Price v. Time, Inc.*, 416 F.3d 1327, 1336, *modified on other grounds on denial of reh'g*, 425 F.3d 1292 (11th Cir. 2005). In particular, "the Court has read the word 'any' to signal expansive reach when construing the Clean Air Act." *New York v. EPA*, 443 F.3d 880, 885 (D.C. Cir. 2006). EPA itself has interpreted the word "any" expansively—for example, EPA argued that the phrase "any other final action" "should be read literally to mean *any* final action of the Administrator," and the Supreme Court affirmed this interpretation. *See Harrison v. PPG Indus., Inc.*, 446 U.S. 578, 585, 589 (1980) (rejecting industry petitioner's argument that the phrase "any other final action" should be construed narrowly); *see also Ali v. Fed. Bureau of Prisons*, 552 U.S. 214, 218–19 (2008) ("[R]ead naturally, the word 'any' has an expansive meaning." (citing *United States v. Gonzales*, 520 U.S.

[326] *See also* 40 C.F.R. § 60.1(a) ("[T]he provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.").

1, 5 (1997))). Here, the phrase "any proposed standard" is properly construed to mean *all* proposals, including proposals that are later withdrawn and replaced with modified proposals. Under the CAA and its implementing regulations, then, the correct applicability date for the GHG NSPS is April 13, 2012.

In previous rulemakings, EPA has kept the date of an initial proposal as the applicability date when it re-proposed a rule, and there is no reason to depart from that practice here. For example, when EPA amended the proposed NSPS for aluminum smelters, it recognized that "[t]he final amendments do not alter the applicability date of the original standards. The standards continue to apply to all new primary aluminum plants for which construction or modification began on or after October 23, 1974, the original proposal date."[327] EPA similarly retained the original proposal date (June 11, 1973) as the applicability date for the opacity standard for Basic Oxygen Process Furnaces, even though the agency re-proposed the opacity standard on March 2, 1977.[328] Likewise, here, when EPA proposed the NSPS on April 13, 2012, this action put the world on notice that new sources would be subject to those standards, in keeping with the Clean Air Act. The final standards therefore apply to all sources that commenced construction after April 13, 2012.

It is especially appropriate to retain the initial proposal date here, where EPA has relaxed rather than strengthened the standards for new sources. *Compare* 77 Fed. Reg. at 22,392 (proposing a standard for coal-fired EGUs of 1,000 pounds of CO_2 per megawatt-hour), *with* 79 Fed. Reg. at 1433 (revising the standard to 1,100 pounds of CO_2 per megawatt-hour). As EPA has recognized in a previous NSPS rulemaking, new sources are on notice that a standard would apply to facilities constructed after the proposal date, even where the final standard was less stringent than the proposed rule.[329] New EGUs have been on notice that they will need to comply with GHG standards since April 13, 2012, and must be held to those standards—"whatever they might be or become"—as required under the Clean Air Act. *City of Painesville*, 644 F.2d at 1189.

Finally, EPA issued the April 2012 proposal in order to avoid litigation over its failure to timely perform its nondiscretionary duty to propose standards of performance for GHG emissions from EGUs. 77 Fed. Reg. at 22,397. If EPA changes the applicability date to January 2014, it would further exacerbate the consequences of its missed deadlines, and would allow more time for sources to commence construction and avoid regulations that should have been

[327] 45 Fed. Reg. 44,207 (June 30, 1980).
[328] EPA, FR Doc. 78-9879, FRL 841-6 (Apr. 13, 1978).
[329] 45 Fed. Reg. 8210 (Feb. 6, 1980) ("[U]tilities were on notice on September 19, 1978, of the proposed form of the standard, and that the standard would apply to facilities constructed after that date," even though "the final SO_2 standard was less stringent than the proposed rule."). *See also Am. Iron & Steel Inst. v. EPA*, 568 F.2d 284, 293 (3d Cir. 1977) ("[T]he adequacy of the notice must be tested by determining whether it would fairly apprise interested persons of the 'subjects and issues' before the Agency.").

proposed long ago. EPA must not further compound the problems from its prolonged delay, and must deem Plant Washington a new source subject to the proposed NSPS.

ii. Plant Washington Did Not Commence Construction by the Original Applicability Date.

There is no question that Plant Washington had not commenced construction by April 13, 2012. The PSD permit authorizing construction of Plant Washington was not final or legally effective until June 15, 2012.[330] EPA has already rejected P4G's contention that it had a final PSD permit and all other required permit approvals necessary to commence construction of Plant Washington as of May 17, 2012, explaining that P4G's "assertion is incorrect, inasmuch as state administrative challenges to the P4G permit remain pending."[331] Even its own spokesperson has acknowledged that P4G lacked required CAA permits and authorizations required to commence construction of Plant Washington at least through April 19, 2012.[332] Moreover, Power4Georgians did not even attempt to enter into illusory construction contracts for Plant Washington until 2013, and it only did so then in an effort to avoid coverage under the proposed NSPS, as explained in the following section.[333] Under the proper applicability date of April 13, 2012, Plant Washington qualifies as a new source.

b. EPA Lacks Sufficient Record Evidence to Designate Plant Washington as an Existing Source Under the January 8, 2014 Re-Proposal.

In its January 2014 re-proposal, EPA explained that it lacked any evidence (much less sufficient credible evidence) to corroborate P4G's unsupported representation that it had commenced constructing Plant Washington. 79 Fed. Reg. at 1461/3 ("Based *solely* on the developers' representations, the projects would be existing sources, and thus not subject to this

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[330] Under Georgia law, a PSD permit is stayed and non-final until 10 days after any challenges to the permit are resolved. O.C.G.A. § 12-2-2(c)(2)(B); Ga. Comp. R. & Regs. 391-1-2-.07(1). A number of groups challenged the PSD permit for Plant Washington, and the Administrative Law Judge did not issue a final decision resolving all challenges until June 5, 2012. Final Decision, *Fall-Line Alliance for a Clean Environment v. Turner*, Dkt. No. OSAH-BNR-AQ-1218695-60-WALKER (June 5, 2012).

[331] *White Stallion Energy Center, LLC v. EPA*, D.C. Cir. Case No. 12-1100, EPA Opp'n to Joint Mot. to Sever and Expedite.

[332] Letter from Alford (P4G) to Turner (EPD) (Sept. 12, 2013) at 2; Georgia EPD Narrative, Plant Washington Application No. 22139 for PSD Permit Extension at 3 (Mar. 27, 2014).

[333] In addition, there is no evidence that the design of Plant Washington had even been fully conceived at the time of the original proposal. The plans for the facility were rudimentary, consisting of a simple list of generic structures and emission controls. *See* Plant Washington Permit Application (Jan. 17, 2008) and Supplemental Application (Nov. 26, 2008) (combined). Even P4G acknowledged how the far the facility's designs were from being finalized, stating that "[i]t will take years to complete the design and construction of a large and complex facility like Plant Washington." Response by P4G in Opposition to Petitioners' Motion for Summary Determination, Fall-Line Alliance for a Clean Environment v. Turner, Dkt. No. OSAH-BNR-AQ-1218695-60-WALKER at 14 (Feb. 14, 2012).

proposal.") (emphasis added).[334] P4G's situation has not improved since then, but has, in fact, worsened.

P4G bases its entire argument on two agreements to supply and erect the Plant Washington boiler. The publicly available versions of these agreements are heavily redacted, lack the most basic information, and do not support P4G's self-serving claim that it has commenced construction of Plant Washington.[335] The unredacted portions of these agreements confirm that P4G has not contracted for fabrication or installation of integral components of the electric steam generator train. The agreements expressly exclude essential elements, such as air pollution controls, that would be required to construct and operate the emission source as permitted.[336] The agreements also contain a disclaimer that they lack technical specifications and designs that must be accepted, approved, and stamped by the Engineering, Procurement, and Construction ("EPC") contractor's engineer before fabrication of any components of the boiler can even begin.[337] Thus, these agreements, without more, do not satisfy the NSPS criteria for commencing construction.

In fact, the current record contains the same gaps and deficiencies that prevented EPA from designating Plant Washington an existing source in the re-proposed NSPS. *See* 79 Fed. Reg. 1461.[338] The record lacks any evidence that P4G has retained an EPC contractor, a

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[334] *See also* PUD TSD at 6 (P4G "ha[s] represented that the project[] ha[s] commenced construction for NSPS purposes, and based *solely* on those representations, the project[] would be considered [an] existing source[] not subject to this rulemaking") (emphasis added); *id.* at 9 (proposing to find Plant Washington has commenced construction "[b]ased *solely* on the developer's representations") (emphasis added).

[335] *See*, Boiler Supply Agreement between P4G and IHI, Inc. (Apr. 12, 2013) (Redacted); Boiler Erect Agreement between P4G and Zachary Industrial, Inc. (Apr. 12, 2013) (Redacted). In addition to these redacted agreements, counsel for several Georgia environmental groups (Fall-Line Alliance for a Clean Environment, Ogeechee Riverkeeper, Sierra Club, and Southern Alliance for Clean Energy) have obtained unredacted versions of the agreements through settlement of a Georgia Open Records Act proceeding. *See Power4Georgians v. Georgia Envt'l Protection Div.*, Sup. Ct. Fulton County, GA, Civ. Action No. 2014CV241165, Confidentiality Agreement (Feb. 11, 2014). P4G has designated these materials as confidential business information ("CBI") and provided them pursuant to a confidentiality and limited-disclosure agreement. *Id.* Counsel will submit a separate set of comments on behalf of the Georgia environmental groups detailing the additional deficiencies in these agreements through EPA's process for submission of information that has been designated as CBI. *See* 79 Fed. Reg. at 1430/3-1431/1.

[336] *Cf.* Boiler Supply Agreement, *supra* n. 335 at Appendix A-1, EPD-000041-R—EPD-000073-R (striking air pollution control devices); Georgia Dep't of Natural Res., Envtl. Prot. Div., Air Prot. Branch, Air Quality Permit for Plant Washington (Apr. 08, 2010) (specifying essential components of electric steam generator process train). *See also Nat'l-Southwire Aluminum Co. v. EPA*, 838 F.2d 835, 837 (6th Cir. 1988) (affirming EPA's interpretation that "under the plain words of [section 111], pollution control equipment is part of a stationary source").

[337] Boiler Supply Agreement, *supra* n. 335 at EPD-000040-R.

[338] In its technical support document for the re-proposal, EPA observed that all of the original participating electric management cooperatives ("EMCs") had severed ties with the project; that P4G had not executed contracts to construct the balance of the plant; that P4G had no customers and no

necessary first step in designing and building an electric generating unit. Contrary to P4G's stated intention, it has not secured contracts to construct the balance of the plant, nor has it sought or obtained an NSPS applicability determination from EPA.[339] All of the electric management cooperatives ("EMCs") that initially supported the proposed plant have severed ties with it and ended any funding commitments.[340] The project remains grossly undercapitalized, and according to P4G's own estimates will cost $3 billion (in 2013-2014 dollars) to complete.[341] Available information shows that P4G has been able to attract only a single investor—Taylor Energy—after all of the original investors ceased funding the project.[342] As P4G itself recognizes, Taylor Energy's role would not be to fund the project, but rather to help "obtain permanent financing," which is still conspicuously lacking for Plant Washington.[343] Moreover, Taylor Energy's available funds are limited to $2 million—less than 0.06 percent of the total projected costs—and there is no indication that these limited funds will be used to finance Plant Washington.[344] Not surprisingly, P4G does not have any power purchase agreements for the electricity the plant would generate.[345] Georgia already has significant

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power purchase agreements; that it had not sought an EPA determination of NSPS applicability; and that it recently requested an extension of the deadline to commence construction under its PSD air permit. *See* PUD TSD at 8 – 9; *see also* 79 Fed. Reg. at 1461/3.

[339] PUD TSD at 8-9.

[340] *See id.* at 8; Cobb EMC, Annual Report 2012, *It's a New Day* ("Cobb EMC has also ended its involvement with the Power4Georgians Plant Washington coal-fired generation facility project. In re-assessing the future requirements for electric load in our area, it was determined that the additional load from the new plant was not needed."); Snapping Shoals EMC, *SSEMC no longer funding coal plant*, *available at* http://www.ssemc.com/news/coolplant.asp , attached as **Ex. 129**, (Snapping Shoals EMC entered into an agreement "releas[ing] Snapping Shoals EMC and the other P4G co-ops from future capital commitments to the Plant Washington project"); Duncan, *Middle Georgia EMCs free From further Plant Washington investment*, The Telegraph (July 16, 2012), *available at* http://www.macon.com/2012/07/16/2096637/middle-georgia-emcs-free-from.html#storylink=cpy., attached as **Ex. 130**.

[341] *POWER4Georgians Comments on TR Rose Report "Power4Georgians Plant Washington Coal-Fired Power Plant: Too High a Price for Consumers,"* at 1 (July 19, 2011), *available at* http://www.power4georgians.com/docs/P4G Analysis of Rose Report 07-19-2011 FINAL.pdf, attached as **Ex.131**.

[342] *See* POWER4Georgians, *Project Summary* (identifying Taylor Energy Fund as the "Project Investor" and Allied Energy Services as the "Project Developer"), *available at* http://power4georgians.com/summary.aspx , attached as **Ex. 132**.

[343] *See* POWER4Georgians, *Taylor Energy Fund to Partner with Power4Georgians to Develop Plant Washington* (Apr. 19, 2012), *available at* http://www.power4georgians.com/docs/P4G Release - Taylor Energy Fund Partners with P4G - 04-19-12 FINAL2.pdf, attached as **Ex. 133**.

[344] SEC Form D for Taylor Energy Fund, L.P. (Aug. 23, 2012) (reporting $2 million total capitalization), *available at* http://www.sec.gov/Archives/edgar/data/1556210/000155621012000001/xslFormDX01/primary_doc.xml, attached as **Ex. 134**.

[345] PUD TSD at 9.

excess coal-fired electric generation capacity, so there is no market for the electricity Plant Washington would generate if it were built.[346]

Most recently, P4G has urged Georgia's Environmental Protection Division ("EPD") to grant an extension of the "commence construction" deadline for its preconstruction air permit under the closely analogous provisions of the PSD program.[347] P4G's admission that it has not commenced construction under its PSD permit, and its explanation for why it needs a permit extension, seriously undermine its present claim that it has commenced construction for NSPS purposes. In its extension request, P4G not only admits that it "has been thwarted in its efforts to commence construction of Plant Washington," but admits that it has not taken the most basic steps to begin the construction process.[348] As of September 2013, P4G acknowledged that:

- It had not obtained vendor guarantees;[349]
- It had not secured necessary construction financing;[350]
- It had not completed designs for the plant;[351] and,
- It had not finalized construction arrangements.[352]

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[346] In one recent proceeding, Georgia Power requested approval of four power purchase agreements ("PPAs") to obtain a total of 1,562 MW of natural gas capacity. *See* Georgia Public Service Commission, Final Order at 8–10, Docket No. 34218 (Mar. 26, 2012). After considering testimony that these PPAs would burden ratepayers with excess capacity and unnecessary costs, the Public Service Commission denied approval of the fourth PPA, which was for approximately 560 MW. *Id.* Unlike Georgia Power, EMCs are not subject to Public Service Commission proceedings to determine whether proposed projects are needed to meet energy needs or are otherwise in the public interest. *See* Georgia Public Service Commission, *Electric* (noting that the Public Service Commission has only "limited regulatory authority" over EMCs), *available at* http://www.psc.state.ga.us/electric/electric.asp , attached as **Ex. 135**. Therefore, the Plant Washington proposal has not been subject to the same type of rigorous public proceedings to determine whether public necessity and convenience justify the project.

[347] *See* Alford Letter, *supra* n. 332 (requesting extension of time to commence construction under P4G's PSD permit for Plant Washington); Georgia EPD Narrative, *supra* n. 332 (same). The principal distinction between the criteria for commencing construction under the NSPS and PSD programs is the extent of liability a developer faces in the event of project cancellation. *See Potomac Elec. Power Co. v.EPA*, 650 F.2d 509, 520 (4th Cir. 1981) ("[T]he requirement to be discerned from prior EPA decisions is one of 'significant liability' [for NSPS] rather than 'substantial loss'" for PSD purposes).

[348] Alford Letter, *supra* n. 332 at 4; *see also id.* at 2, 3.

[349] *Id.* at 2. P4G also complained that EPA's MATS rule prevented P4G from obtaining vendor guarantees and commencing construction. But this complaint is unpersuasive. P4G voluntarily agreed to meet the MATS requirements years before it was required to and consistently expressed confidence that Plant Washington could meet all MATS requirements. *See, e.g.,* EPA opposition brief to severance motion, *White Stallion Energy Center*, *supra* n. 332, at 12 n. 6 (observing that "P4G entered into a settlement agreement to resolve state administrative litigation pursuant to which it voluntarily agreed to comply with [the MATS] new source standards years *sooner* than it might have otherwise had to").

[350] Alford Letter, *supra* n. 332 at 2.

[351] *Id.* at 3, 4.

[352] *Id.* at 4.

P4G not only has failed to take the most basic preparatory steps for commencing construction prior to the NSPS reproposal's publication date, it has asserted that it cannot do so until EPA *finalizes* the GHG performance standards for EGUs.[353]

In response to P4G's request for an extension, Georgia's EPD has proposed to extend the Plant Washington PSD permit with additional conditions and a "hard deadline" of October 15, 2015.[354] Under EPD's proposed conditions, before P4G can commence construction of the facility, it must first conduct and submit additional modeling demonstrations for SO_2, NO_2, and $PM_{2.5}$.[355] These modeling demonstrations will take significant time to complete, and P4G cannot commence construction until they are submitted.

The facts are clear: contrary to P4G's self-serving representations, Plant Washington has not commenced construction and is not on the verge of doing so. Ultimately, P4G entered the Boiler Supply and Boiler Erection agreements in an effort to avoid coverage under the initial NSPS proposal, rather than to complete a program of continuous construction of Plant Washington within a reasonable time. This type of arrangement is not sufficient to "commence construction" for NSPS purposes. *See Potomac Elec. Power Co. v. EPA*, 650 F.2d 509, 513-14 (4th Cir. 1981) (contracts "entered into simply for purposes of avoiding the NSPS requirements" do not satisfy the NSPS definition of "commence construction"). Based on the record in this rulemaking, EPA cannot determine that Plant Washington has commenced construction for NSPS purposes, nor can EPA designate the proposed project an existing source.

2. Holcomb

EPA may not in this rulemaking determine that the proposed Holcomb 2 plant in Holcomb, Kansas is an existing source. Indeed, EPA itself has identified many of the reasons that the Holcomb plant has not commenced construction and should not be considered an existing source.[356] While the agency also notes that the project's developers have represented to EPA that the project has already commenced construction, these unsupported assertions are not sufficient for EPA to conclude that Holcomb 2 is an existing source in this rulemaking, particularly in the face of substantial contrary evidence.

a. EPA Lacks Sufficient Record Evidence to Conclude that the Holcomb 2 Plant Is an Existing Source.

EPA may not rely on the unsupported assertions of Holcomb's developers to conclude that the Holcomb 2 project is an existing source. In its TSD, the agency notes that the Holcomb developers (specifically, Tri-State Generation and Transmission Association) have represented

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[353] *Id.* at 3-4.
[354] Georgia EPD Narrative, *supra* n. 332 at 4.
[355] *Id*.
[356] *See* PUD TSD at 9-10.

to EPA that the Holcomb project has commenced construction, both in a February 13, 2013 letter and in comments on EPA's 2012 NSPS proposal.[357] While Tri-State asserts in its February 13, 2013 letter that its sunk costs are sufficient to have "commence[d] construction" of Holcomb, EPA has correctly abandoned the approach of granting certain sources "transitional" status based on sunk costs. Furthermore, EPA's regulations defining commencement of construction do not include a developer's sunk costs among the factors relevant to such a determination. *See* 40 C.F.R. § 60.2. Rather, only a continuous program of actual construction or binding contracts to complete construction of the facility within a reasonable time constitute commencement of construction for NSPS purposes. *Id.*

There is no question that Tri-State has not begun a continuous program of physical construction. In its 2012 comments to EPA, however, Tri-State represents that it has entered into two contracts for the Holcomb project: one to construct the steam generator and another to construct the steam turbine/electricity generator.[358] But for a host of reasons, EPA must reject Tri-State's claims and determine that that the Holcomb project has not commenced construction for the purposes of the proposed NSPS.

First, in response to a Freedom of Information Act Request, EPA has advised that it does not have copies of either contract referenced in the Tri-State's 2012 comments.[359] It would be entirely inappropriate for the agency to conclude that these contracts satisfy the "commence construction" requirement without having ever reviewed them. It would be equally inappropriate for EPA to so find without including these contracts in the public docket and accepting public comment on them. Without these contracts, and without an opportunity for public review of them, EPA lacks an adequate evidentiary basis to credit Tri-State's claims.

Moreover, Tri-State's own statements regarding these two contracts make clear that they do not meet the "commence construction" definition for NSPS purposes. In a section of its 2012 comments entitled "Pre-Construction Planning," Tri-State advises that while it has awarded two contracts, many parts of the facility have yet to be contracted or designed:

> Proposals for air quality control systems have been received and evaluated, but no contract has been awarded. At the same time that this contract is awarded, a single "engineer, procure, and construct" (EPC) vendor will be selected to

[357] *See id.* at 9 & n. 21-22.

[358] *See id.* at 9 & n.22; *see also* Tri-State Generation & Transmission Ass'n, *Comments on Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660-9845 (June 25, 2012) (hereinafter "Tri-State 2012 Comments"), at 9, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-9845, attached as **Ex. 136**.

[359] *See* Earthjustice, Freedom of Information Act Request regarding Contracts Referenced in EPA's Technical Support Document for the EGU GHG NSPS Proposed Rule, Docket ID. No. EPA-HQ-OAR-2013-0495 (Jan. 29, 2014), attached as **Ex. 137**; EPA, E-mail correspondence from C. Hamborg to T. True regarding EPA's Final Disposition in Request EPA-HQ-OAR-2013-0495 (Feb. 19, 2014), attached as **Ex. 138**.

> integrate the steam generator, turbine generator, and air quality control systems, and to provide the final overall design and construction of Holcomb 2.[360]

Similarly, in a declaration filed in federal court in Washington, D.C. on April 27, 2012, Tri-State's Executive Vice President and General Manager characterized its expenditures to date on the Holcomb project as "engineering and legal costs," and advised that Tri-State had not yet commenced construction on the plant.[361] Tri-State may have placed an order for a boiler, but that does not constitute a binding contract for construction of all structures and facilities essential to the eventual erection or installation of the boiler at the project site.[362] Construction of Holcomb 2 itself has not yet commenced.

b. Substantial Contrary Evidence Shows that the Holcomb 2 Plant Has Not Commenced Construction.

Not only does EPA lack evidence to conclude in this rulemaking that the Holcomb 2 plant is an existing source, substantial contrary evidence demonstrates that the Holcomb 2 facility has not yet commenced construction, and be unable to do so for many years to come.

i. The Holcomb Developers Have Not Received Necessary Approval from the Rural Utilities Service.

Holcomb's developers may not lawfully commence construction until the Rural Utilities Service ("RUS") issues additional approvals of the project—approvals that the developers have neither requested nor received. As EPA notes, a federal court in Washington, D.C. has held that RUS must prepare a full environmental impact statement before granting Sunflower any of the additional federal approvals it needs to proceed with the project. *See Sierra Club v. U.S. Dep't of Agric.*, 841 F. Supp. 2d 349 (D.D.C. 2012), *appeal dismissed*, 716 F.3d 653 (D.C. Cir. 2013).[363] Sunflower has not requested the approvals necessary to commence construction of Holcomb 2, and RUS has not yet begun the lengthy process of preparing a full environmental impact statement, which it must complete before granting the necessary approvals.

In 2009, Sunflower signed a consent agreement with the state of Kansas that would significantly modify its plans for Holcomb. RUS, which granted approvals to Holcomb in 2007 based on earlier plans, has "emphatic[ally] conclu[ded] that Sunflower must seek additional approvals" from the agency before the Holcomb project may proceed with its new plans

[360] Tri-State 2012 Comments at 9.
[361] *See* Decl. of Kenneth J. Anderson, Dkt. No. 1371309, Case No. 12-1100 (filed April 27, 2012) at ¶¶ 17, 14, attached as **Ex. 139.**
[362] *See* Press Release, *Toshiba Wins Contract to Supply Steam Turbine/Generators for Holcomb Expansion Project in the USA* (Toshiba characterizes its contract with Tri-State as one for the "supply of equipment"), *available at* http://www.toshiba.co.jp/about/press/2012_01/pr1901.htm , attached as **Ex. 140**.
[363] *See also* PUD TSD at 9-10.

following the 2009 settlement agreement with Kansas. *Sierra Club*, 841 F. Supp. 2d at 362.[364] As RUS has noted, the 2009 agreement has significant ramifications for the recovery of Sunflower's outstanding federal debt.[365] Thus far, however, Sunflower has neither sought nor received approval for the 2009 reconfiguration. Moreover, Sunflower's 2007 agreement with Sunflower explicitly prohibits the company from entering into any contract to develop an additional unit without prior written approval from RUS.[366] Again, Sunflower has neither sought nor received approvals for the alleged new contracts for the project's boiler and steam generator. Entering into these contracts without RUS approval is a breach of Sunflower's 2007 agreements with the agency. Accordingly, EPA must not bless Sunflower's disregard for the contracts with RUS governing its continuing debt obligations to the United States, nor should it ignore the "emphatic" position of its sister agency.

ii. The Holcomb Project May Not Commence Construction Without A Valid PSD Permit.

The PSD provisions of the Clean Air Act require the proponent of a project to obtain a valid permit prior to commencing construction. *See* 42 U.S.C. § 7475.[367] On December 16, 2010, the Kansas Department of Health and Environment ("KDHE") issued a PSD permit to

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[364] *See* Sierra Club, Fed. Defs.' Supplemental Brief Regarding Remedy, Dkt. No 117 at 6 (filed May 27, 2011), attached as **Ex. 141** ("RUS has concluded that due to the significant changes Sunflower made to the configuration of the Holcomb Expansion Project subsequent to the Agency's approvals in 2007, the Holcomb Expansion Project requires new RUS approvals."); *see also id.* at 13 ("Due to the material changes in the development of the Holcomb Expansion Project . . . RUS has concluded that its approvals and implementing documents require Sunflower to seek new approvals from RUS for the drastic changes to the Holcomb Expansion Project from the proposal RUS previously reviewed and approved in 2007.").

[365] *Id.* at 12-13 ("Sunflower did not consult with or seek approval from RUS before signing the [2009] Settlement Agreement, affirmatively and unilaterally withdrawing its application for Unit 3. Thus, RUS is interested in discussing the financial ramifications of the Settlement Agreement on RUS, and in particular, on the approximately $26 million RUS was to have received if Unit 3 commenced commercial operation.").

[366] Under the terms of the loan contracts and mortgages between Sunflower and RUS that govern Sunflower's substantial federal debt, Sunflower agreed "that it would not 'enter into *any agreement or other arrangements . . . for the development of Holcomb Unit 2* without the prior written approval of RUS.'" *Sierra Club*, 841 F. Supp. 2d at 353 (emphasis added); *id.* at 353 n.3 ("In addition, and even more comprehensively, Sunflower also agreed []that it w[ould] not '[c]onstruct, make, lease, purchase or otherwise acquire any extensions or additions to its system *or enter into any contract therefore*' without the prior written approval of RUS.") (emphasis added).

[367] The definitions of commencing construction under the NSPS and PSD provisions differ slightly. *Compare* 40 C.F.R. § 60.2 *with* 42 U.S.C. § 7479(2). However, while the NSPS regulatory definition of commence construction does not explicitly require a source to have obtained pre-construction approvals, a contract that would satisfy that definition would likely also fall under the statutory definition that applies to the PSD program. EPA should not interpret the CAA to allow a source to commence construction for purposes of the NSPS while at the same time violating of the Act's PSD provisions.

Sunflower Electric Power Corporation, Holcomb's other main developer. The Sierra Club challenged the permit, and on October 4, 2013, the Kansas Supreme Court held the permit unlawful, vacated it, and remanded the matter to KDHE. *See Sierra Club v. Moser*, 310 P.3d 360 (Kan. 2013). Accordingly, because Holcomb currently lacks a final, valid PSD permit, Sunflower is legally barred from having commenced construction on the project.[368]

Nor is Sunflower close to receiving a final, valid PSD permit. On January 16, 2014, KDHE published a draft "addendum" to the vacated permit and solicited public comment.[369] As Sierra Club has noted in comments, the draft "addendum" complies with neither the CAA nor Kansas's State Implementation Plan and fails to address the specific deficiencies identified by the Kansas Supreme Court. The proposed "addendum" has not been finalized, and a new permit has not been issued.

Moreover, Sunflower could not have lawfully commenced construction before its permit was vacated by the Kansas Supreme Court. EPA Region 7 explicitly advised the state permitting agency and Sunflower before, during, and after the permitting process that failure to include one-hour NO_x and SO_2 emission limits was unlawful.[370] Additionally, the PSD permit was stayed during the pendency of the litigation challenging the permit. The stay was issued on July 20, 2011 and lasted until the permit was reversed and vacated by the Supreme Court on October 4, 2013.[371] Accordingly, Holcomb's developers cannot have commenced construction in 2012, and EPA must find that Holcomb is not an existing source for the purposes of the proposed NSPS.

iii. The Developers of Holcomb Are Not Planning to Construct the Project for More Than a Decade, If Ever.

The facts in the record reveal that the developers of Holcomb have no intention of constructing or operating the project for more than a decade, if ever.[372] As EPA noted in its

[368] *See also* PUD TSD at 4-5 (noting that EPA does not consider projects that "lack effective PSD permits" to be "capable of commencing construction in the very near future").

[369] *See* Kansas Dep't of Health and Envt., Sunflower Electric Power Corporation, *Holcomb Draft Addendum* (Jan. 16, 2014), *available at* http://www.kdheks.gov/bar/sunflower/sunflower.html, attached as **Ex. 142**.

[370] *See* Letter from Becky Weber, EPA, to J. Mitchell, Kansas Dept. of Health and Environment, April 2, 2011, attached as **Ex. 143**; Letter from Becky Weber, EPA, to J. Mitchell, Kansas Dept. of Health and Environment, April 2, 2011, attached as **Ex. 144**.

[371] *See* Kansas Dept. of Health and Environment, Order Granting Request for a Stay, Case No. 11-E-80-BOA (July 20, 2011), attached as **Ex. 145**; Sierra Club, Request for Clarification, Case No. 11-E-80-BOA (DATE), attached as **Ex. 146**. KDHE has refused to clarify the nature of the stay, *see id.*, but the only interpretation of the stay that does not run afoul of the Clean Air Act dictates that the entire permit remained stayed during the pendency of appeal. Hence, this is the interpretation of the stay EPA must adopt.

[372] *See* 40 C.F.R. § 60.2 (only contracts that require construction within a "reasonable time" may indicate commencement of construction).

TSD, Tri-State submitted a resource plan update to state regulators in 2012 representing that no new coal-fired generating capacity—not the Holcomb project nor any other coal-fired facility—is either needed or expected to be added to Tri-State's portfolio within the next 20 years.[373] Since then, Tri-State has submitted a 2013 annual update to its resource planning document, also filed with state regulators.[374] In its 2013 update, Tri-State confirms that for numerous reasons, development of the Holcomb project is a distant possibility at best.

In its initial 2010 resource plan, Tri-State projected that it likely would not need any new coal generation resources during the 20-year planning horizon, with 23 out of 24 modeled scenarios supporting this result, and one modeled scenario predicting a possible need for a fraction of additional power from a new coal-fired plant in 2026.[375] In its 2013 Update, Tri-State notes that "[t]he current forecast indicates that Tri-State's Member load continues to grow but at a slower rate than was projected in the previous update."[376] Based on additional modeling incorporating this slowed growth, Tri-State concludes that "no new capacity resources are required to serve firm load and obligations through 2028 for the median load forecast case."[377] In other words, Tri-State will likely never need any power from the Holcomb plant. If it ever does need that capacity, it will not be until 2028—years past the end of the eight-year regulatory cycle for the proposed NSPS.

The most significant change considered in the 2013 Update is the amendment and strengthening of Colorado's renewable energy standard ("RES").[378] As a result of the heightened RES, "[b]y 2020 Tri-State will need to acquire additional renewable energy either through self-build generation, power purchase agreements, or the purchase of renewable energy credits."[379] The mandate to achieve a higher percentage of renewable resources makes the already-unlikely development of Holcomb even more remote.

Indeed, Tri-State candidly acknowledges in the 2013 Update that no progress has been made on Holcomb in the last several years, and the unit would at the earliest fill a possible

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[373] *See* PUD TSD at 10 & n.26.

[374] *See* Tri-State Generation and Transmission Association, Inc., Electric Resource Plan Annual Progress Report (filed with the Colorado Public Utilities Commission on Oct. 31, 2013) [hereinafter "Tri-State 2013 Update"], attached as **Ex. 147.**

[375] *See* Tri-State Generation and Transmission Association, Inc. , Integrated Resource Plan/Electric Resource Plan (filed with the Colorado Public Utilities Commission in Nov. 2010) , *available at* http://www.tristategt.org/ResourcePlanning/documents/Tri-State_IRP-ERP_Final.pdf.

[376] Tri-State 2013 Update at 2.

[377] *Id.* at 7.

[378] Although Holcomb is proposed to be constructed in Kansas, Tri-State is headquartered in Colorado. *See also id.* at 7 ("New in this APR is the enactment of Colorado SB13-252 which modified the existing RES. The additions and modifications that apply to Tri-State increases [sic] the RES requirements from 10 percent to 20 percent by 2020 by requiring that the energy provided by each generation and transmission cooperative electric association to its Member Systems in Colorado be from eligible energy resources.").

[379] *Id.* at 8.

resource need in 2028.[380] Similarly, in a letter dated March 12, 2013 filed with the Colorado Public Utilities Commission, Tri-State advised state regulators that "no final decision has been made as to whether to proceed with construction of [Holcomb 2] and, if so, when that would occur."[381] Tri-State further represented to state regulators that it is "keep[ing] its options open" with respect to Holcomb and that "Tri-State is continuing to explore the development of the Holcomb 2 Project but, as of this date, has not made any final decisions with respect to that project."[382] Notably, these statements postdate the 2012 contracts that Tri-State now argues are adequate to commence construction.

Tri-State has repeatedly represented to state regulators that it does not need the power from the Holcomb project anytime soon (if ever) and has not yet decided whether to proceed with the project. These statements cannot be reconciled with a finding that the Holcomb project is "on the verge of construction,"[383] and certainly not with a finding that the project has entered into binding commitments to complete construction within a reasonable time.[384] Rather, Tri-State appears to be hoping to sit on a project that is grandfathered out of compliance with the proposed NSPS and preserve its flexibility to build an unregulated facility at some distant future date if needed. Based on the record in this rulemaking, EPA cannot determine that Holcomb has commenced construction for NSPS purposes, nor can it designate the proposed project an existing source.

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[380] *See id.* at 10 ("Since the 2010 ERP and since the last APR, development at the Holcomb site has largely been unchanged. As in the previous two APR cycles, this APR is intended to be an update and does not involve modeling any specific unit in the planning horizon. However, a similar potential unit is included in the expansion planning process. Tri-State similarly maintains several potential sites but does not prescribe a timeline for their development within the resource planning process."). *See also id.* at 9 ("Tri-State has positioned itself to have viable options to meet future needs that may include demand side alternatives, natural gas generation, renewable generation or baseload generation. No firm commitments have been made at this time as to the timing, technology, size or location of new generation projects.")

[381] *See* Letter from K. Rief, Tri-State General Counsel and Senior Vice President to Chairman J. Epel, Commissioner J. Tarpey, and Commissioner P. Patton, Colorado Public Utilities Commission (March 12, 2013), at 2, attached as **Ex. 148.**

[382] *Id.*

[383] PUD TSD at 10.

[384] *See* 40 C.F.R. § 60.2.

3. Two Elk[385]

As with Port Washington and Holcomb, EPA has no basis to presume that Two Elk is an existing source for NSPS purposes. If Two Elk's developers intend to move forward with the project, it must be subject to the proposed NSPS, along with all other new coal-fired EGUs.

Sierra Club and Powder River Basin Resources Council have provided extensive information documenting that Two Elk's 2003 PSD permit has expired due to lack of construction since 2007.[386] While EPA is correct that the State of Wyoming accepted Two Elk's representation that it commenced construction in 2005 and had a valid permit as of 2007, the developers have not continued construction since that time. To the contrary, the evidence overwhelmingly shows that construction on Two Elk has not been continuous (and has lapsed entirely in recent years) and that its PSD permit has therefore expired.[387] Furthermore, even if Two Elk did "commence construction" of the facility to which state regulators issued the 2007 permit, it has not commenced construction of the modified project it now plans to build, and for which it must obtain a new permit.

The evidence has only grown stronger since 2012 that Two Elk's 2003 PSD permit for a coal-fired power plant (now more than a decade old) has lapsed. In its October 2013 status report to the Wyoming Department of Environmental Quality ("WDEQ"), Two Elk states that it has a single employee, that it has negotiated an agreement to purchase a gas turbine, and that only "preliminary design" on the turbine has begun.[388] Correspondence with WDEQ indicates that a 45 MW gas turbine is included in the equipment covered by the 2003 permit for the coal-fired power plant.[389] This purchase agreement does not suffice as commencing construction of

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[385] As of the September 2013 publication date of the PUD TSD, EPA made clear that it considered the Two Elk plant as having commenced construction. *See* PUD TSD at 10-11. However, in the Federal Register notice for the proposed NSPS, the agency makes no mention of Two Elk in the section on projects still under development, but discusses Plant Washington, Holcomb, and the now-cancelled Wolverine project only. *See* 79 Fed. Reg. at 1461-62. It is unclear what this omission signifies, and Joint Environmental Commenters would commend a determination by EPA that it no longer considers Two Elk exempt from the proposed NSPS. However, because the agency's intention in this regard is ambiguous, Joint Environmental Commenters assume in these comments that EPA has not changed its mind with regard to Two Elk in order to preserve any arguments they may have with regard to that project.

[386] Sierra Club *et al.*, *supra* n. 200, at Exs. 60-68, 76, & 77, attached as **Exs. 149-59.** *See also* Sierra Club and Powder River Basin Res. Council, Comments on the Two Elk Generation Partners Coal-Fired Power Plant, EPA-HQ-OAR-2011-0660-14900 (Sept. 27, 2012), at 5-6 and Exs. 3, 12, & 13, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-14900, attached as **Exs. 160-63.**

[387] *See* Sierra Club and Powder River Basin Res. Council, *supra* n. 386, at 5-6; Sierra Club *et al.*, *supra* n. 200, at 78-79, 89-90.

[388] Letter from B. Enzi, Two Elk Power Company, to L. Esch, Industrial Siting Div., WDEQ (including attachments) (Oct. 31, 2013), attached as **Ex. 164.**

[389] E-mail correspondence from S. Dietrich, Director, Air Quality Division, Wyoming Dept. of Environmental Quality, to S. Anderson, Powder River Basin Resources Council (Jan. 29, 2014), attached

the coal-fired boiler. Nor is there any evidence of a valid, existing contract or of any physical construction activity on that coal-fired boiler. Two Elk's October 2013 status report also confirms, as noted in the 2012 comments submitted by several of the Joint Environmental Commenters, that the developers instructed Pacificorp to cease all interconnection work as of March 2012, and had not (as of the date of the status report) lifted this suspension. The state's site inspection report from October 2013 notes that "[n]o construction activities could be confirmed to have taken place in the last twenty-four months" at the Two Elk site.[390] Two Elk's 2003 PSD permit's own terms state that it expires if there is a lapse of construction for 24 months. Thus, based on the evidence in the record, EPA cannot reasonably come to any other conclusion than that Two Elk's permit has expired. EPA's reliance on Wyoming's supposed determination that Two Elk's decade-old permit remains valid lacks support in the record and ignores the stark evidence to the contrary.

Further, Two Elk is not even purporting to build the same plant as was authorized in its now expired 2003 permit. On July 20, 2010, Two Elk sought a revision to its PSD permit to change the design of its boiler such that it would burn biomass.[391] On August 10, 2010, the Air Quality Division of WDEQ sought more information from Two Elk to support this application, but—consistent with the company's apparent abandoment of the project—has received no further information from the plant developers.[392]

In sum, Two Elk has not performed any construction activity that would qualify for continuous "construction" at the site for many years, if ever.[393] As evidenced by its 2010 application for a boiler redesign it has yet to complete, Two Elk remains in the design phase for its plant. If Two Elk seeks to move forward with its project (which appears unlikely), it must therefore apply for a new PSD permit. Given the expiration of the project's PSD permit and the demonstrated lack of any construction activity at the project site, EPA must reject Two Elk's conclusion that the plant is an existing source for the purposes of this rulemaking and must instead determine that the proposed NSPS will apply to Two Elk if and when the facility is constructed.

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as **Ex. 165**; e-mail correspondence from S. Anderson, Powder River Basin Resources Council to S. Dietrich, Director, Air Quality Division, Wyoming Dept. of Environmental Quality (Jan. 28, 2014), attached as **Ex. 166.**

[390] WDEQ, Inspection Report for Two Elk Project (Oct. 2013), attached as **Ex. 167.**
[391] Sierra Club *et al.*, *supra* n. 200, at Ex. 66.
[392] *See* Dietrich-Anderson email correspondence, *supra* n. 389.
[393] "Construction means fabrication, erection, or installation of an affected facility." 40 C.F.R. § 60.2. "Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable." *Id.*

B. EPA Lacks a Factual or Legal Justification for Distinguishing These Sources from Other New Coal-Fired Power Plants.

Assuming that Port Washington, Holcomb, and Two Elk have yet to "commence construction," the proposed emission limit of 1,100 lb CO_2/MWh for coal-fired utility boilers should apply to these sources pursuant to section 111(a)(2) of the Act, which sets out a bright-line rule of applicability: plants that have not yet commenced construction by the date of the proposal are subject to the standard. *Id.* In proposing a separate subcategory for Holcomb and Plant Washington (and perhaps different subcategories for each), EPA makes the same error it did with regard to "transitional sources" in the 2012 NSPS proposal.

As the Joint Environmental Commenters have previously argued, EPA must establish performance standards for new sources within a listed category. 42 U.S.C. § 7411(b). Those standards apply to *any* source in the category that commences construction after EPA proposes the standards. *Id.* § 7411(a)(2). While EPA "may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards," *id.* § 7411(b)(2)(emphasis added), section 111 does not provide EPA with discretion to establish a special standard for a particular source that cannot be distinguished by type, size, or class.

The agency asserts that section 111 "does not require that the EPA propose such standards for *all* new sources or for *any* new source. The EPA may fulfill [Section 111's] directive by proposing standards that cover some, but not all, sources that newly commence construction or modification."[394] But EPA must have a rational basis for distinguishing between sources, and the authority that EPA cites for this assertion does not support its approach of distinguishing otherwise similar coal-fired EGUs based on when the projects were conceived by their developers. For example, EPA cites *National Lime Association*, 627 F.2d at 426 & n.28, where the Court considered separate standards set for three different *types* of lime kilns, each utilizing different technology.[395] The agency does not claim that Plant Washington and Holcomb are situated differently from other coal-fired EGUs because they are proposing to utilize distinct technologies; rather, the only distinction is that they are purportedly "on the verge of construction" (an assertion that the record evidence does not, in any event, bear out).

[394] PUD TSD at 17 (quoting 77 Fed. Reg. at 22,425-26).

[395] In the rule establishing performance standards for lime kilns, it is not clear that EPA sought to exclude any new lime plants, since the agency projected that all new kilns would be rotary. *See National Lime Ass'n*, 627 F.2d at 426 n.28 ("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."); 42 Fed. Reg. 22,506, 22,507 (May 3, 1977) ("[V]irtually all the new kilns that have been built in the last few years have been of the rotary type . . . . [T]he present trend is to build and operate rotary kilns whenever possible."). Moreover, the exclusion of non-rotary kilns from the lime standards was not part of the petitoner's legal challenge to the rule. The D.C. Circuit's approval of EPA's action in that case does not, therefore, confirm that the agency has free reign to exclude certain new sources from NSPS applicability.

Likewise, the prior rulemakings that EPA cites distinguished sources based on "type" and "size," consistent with the statutory language. *See* 72 Fed. Reg. 27,178 (May 14, 2007) (distinguishing fluid coking units, delayed coking units, and process heaters as different types of refinery sources); 40 C.F.R. §§ 60.4305(a), 60.4310(a)(d) (distinguishing gas turbines with less than 10 MMbtu/heat input, emergency units, and combustion turbine test cells by size); *id.* § 60.301(b) (distinguishing metal furniture surface coating operations that use less than 3.842 liters of coating per year by size); 49 Fed. Reg. 2636, 2637 (Jan. 20, 1984) (distinguishing process emission sources at natural gas processing plant from other emission sources at the plant by type of source).

If fully developed, Plant Washington and Holcomb would emit millions of tons of CO_2 annually, and cannot be distinguished from other coal-fired EGUs on the basis of size. Thus, past rules in which EPA exempted some subcategory of *de minimis* or smaller sources are not analogous. Nor are these plants a different "type" of source; they are coal-fired EGUS no different in kind from other new plants that will be subject to the proposed NSPS. The rulemakings in which EPA distinguished different types of emission points or different types of sources are therefore also inapposite. EPA acknowledges that any discretion to regulate new sources in stages, as it proposes to do, would be "bounded by the principle of rationality."[396] In fact, there is no rational basis to establish an alternate standard for two or three new sources that are not technologically different, nor different in "class, type, or size," from other new sources.

Moreover, EPA's reasoning for not applying the 1,100 lb CO_2/MWh standard to the projects discussed above is neither consistent with the statute's language and purpose nor practical from a policy perspective.[397] The agency states that these plants have different "opportunity costs" from other sources and therefore may have a different BSER, yet admits that it has "not formulated a view at this time" as to what the BSER would be.[398] According to EPA, "imposition of a CO_2 standard implicates a proposed EGU's fundamental site, fuel, and technology choices," such that if a source is "truly is on the verge of construction in order to meet a valuable near-term resource need or market opportunity, and if complying with the 1,100 lb CO_2/MWh standard would require changes to the project's fundamental site, fuel type, or combustion technology choices that could not be accomplished without a degree of delay that would cause that valuable opportunity to be missed, then making the project subject to the standard could entail high opportunity costs."[399] EPA posits that "one possible

[396] PUD TSD at 17 (quoting 77 Fed. Reg. at 22,425-26).
[397] Although EPA provided this reasoning with respect to the Wolverine plant (which has since been canceled by its developers), the agency apparently intends to apply the same reasoning to Holcomb and Plant Washington. *See* 79 Fed. Reg. at 1461 (stating that Holcomb and Plant Washington will be "addressed in the same manner as the Wolverine project" if they have not already commenced construction).
[398] PUD TSD at 19.
[399] *Id.* at 19-20.

interpretation of" the cost element of BSER is "that opportunity costs of the nature just described could be a type of cost relevant to the determination of BSER."[400]

As EPA itself concedes, its ability to establish a meaningful performance standard based on opportunity costs is impeded not only by its uncertainty as to whether a plant is on the verge of construction, but also by its "lack of information concerning the degree of difficulty the project would face in adapting its design to incorporate CCS and the associated consequences for the project's development schedule."[401] Such information is primarily, if not wholly, within the control of the company itself, making it impossible for EPA to make an objective decision and to treat all sources fairly.[402]

More importantly, Congress specified in section 111 that an NSPS would apply to entire *categories* of sources, and EPA has never in the past carved out a one- or two-source subcategory in determining a proper emission limits pursuant to a BSER determination. Congress has already spoken directly to how a source's construction status relates to the application of a new emissions standard: if the source has not commenced construction, it is subject to the standard. If it has commenced construction, it is not.[403] This bright-line rule for sources within the same general category obviates the need for delving into the details of each and every source's construction status and "opportunity costs." It is for this reason that Congress crafted section 111 in the way that it did, and EPA lacks the authority to revisit Congress's decision.

Creating a subcategory for one or two facilities that have not yet commenced construction would also reward facilities for ignoring state of the art technology. Once EPA publishes a proposed rule, sources are on notice as to the technology they should include in the plant's design. Indeed, EPA notes that some proposed sources have changed design since EPA's initial proposed rule and now are capable of meeting the NSPS.[404] EPA must apply the NSPS even-handedly and fairly to *all* new sources, rather than allowing proposed sources that have ignored this notice to build plants that are less-controlled while at the same time requiring proposed sources that heeded the notice to comply with the NSPS.

Creating a subcategory for one or two facilities based solely on the plants' stage of development also departs from EPA's past practice. As discussed above, none of the previous NSPS rulemakings cited by EPA creates a subcategory for certain hand-picked sources based on

[400] *Id.* at 20
[401] *Id.*
[402] Providing an opportunity for public comment might mitigate the problem of one-sided information, but citizens will face the same challenges as EPA in determining the true facts surrounding any plant's development.
[403] *See Sierra Club*, 657 F.2d at 325 ("The standards must to the extent practical force the installation of all the control technology that will ever be necessary on new plants at the time of construction when it is cheaper to install.").
[404] PUD TSD at 4-5.

the timing of those projects or their “opportunity costs.” *See, e.g.,* 42 Fed. Reg. at 22,507 (setting standards for rotary kilns, but not other types of kilns, because the vast majority of the industry uses that particular technology); 74 Fed. Reg. 51950, 51953 (Oct. 8, 2009) (setting a more lenient standard for modified coal preparation and processing plants based on “physical layout,” while recognizing that reconstructed sources, as well as new sources, can “take design options into account” and therefore could meet a stricter standard). Even if an “opportunity cost” approach to section 111 performance standards were viable and could be limited to situations in which a new source is “on the verge of construction,” Holcomb and Plant Washington would not qualify, as explained above. Both plants are far from beginning construction.

Additionally, we do not share EPA’s apparent concern regarding the “extent that [its] own actions related to the MATS rule may have hampered developers’ efforts to commence construction”[405] provide a basis for special treatment of these sources. 79 Fed. Reg. at 1461 n. 126. As shown above, EPA’s actions were not the cause of the developers’ delay. Rather, the projects were mired in legal issues and/or have been lacking in investor interest for years—issues entirely unrelated to the MATS rule. In any case, this is not a relevant factor to EPA when making a BSER determination or setting a performance standard.

Finally, we respectfully disagree with certain statements EPA has made in justifying its decision not to set an alternative standard for Holcomb and Plant Washington at this time. Namely, we disagree with agency’s position that “applicability of a section 111(d) standard for CO_2 emissions would mitigate any negative impact that might arise from not covering the project under the proposed 1,100 lb CO_2/MWh standard.”[406] EPA further contends that “it is possible that a section 111(d) standard would be similarly stringent as any alternate GHG standard of performance that could have been developed for [these projects] consistent with retaining [their] ability to commence construction in the very near term.”[407] EPA cannot rely on regulations that will be promulgated under section 111(d) to cover these sources. Full implementation of the existing-source regulations will take years even after EPA issues its emission guidelines this June, and any standard that eventually applies to existing sources will be limited by the opportunities available to reduce emissions from plants that are already built (which are very differently situated from those that are merely “on the verge of construction.”)[408] For sources that emit millions of tons of CO_2 annually, the delay in imposing performance standards coupled with the more limited scope of the existing source standard creates a regulatory gap that will have a substantial impact on human health and the

[405] EPA made this assertion specifically with respect to the Wolverine Plant; it is unclear whether the agency intends this reasoning to apply to Holcomb, Plant Washington, and Two Elk as well.
[406] PUD TSD at 21.
[407] *Id.*
[408] EPA has recognized that “[i]t is much easier, both in technical and practical terms, to consider the air quality impacts and pollution control requirements of a major new source of air pollution before it has been constructed and has begun operation rather than after.” 54 Fed. Reg. 27,274-01, 27,281 (June 28, 1989).

environment. To rely on a forthcoming 111(d) standard as an excuse for exempting certain new sources from a 111(b) standard also creates bad precedent that could be applied beyond the context of this particular rulemaking.

C. EPA Must Formally Determine Whether These Plants Qualify as Existing Sources.

Finally, EPA is vague as to if, when and how it plans to make a final determination as to whether the sources discussed herein have "commenced construction," and are therefore existing sources. In the final rule, EPA should make clear the process by which it will make this determination, including the time frame for this decision and the opportunity for public participation. As a number of the Joint Environmental Commenters explained in their 2012 comments on the initial NSPS proposal, state environmental agencies have not been reliable in enforcing EPA's guidance or other authorities interpreting this definition.[409] Indeed, the state of Kansas recently enacted into law a provision that purportedly gives the state permitting agency authority to regulate greenhouse gas emissions from sources under development and requires the state agency to base its regulation on a variety of factors not permitted under the CAA.[410] Given the history of state backing of these plants, including issuance of decisions later struck down by state courts, it is especially inappropriate to rely on the states to enforce the definition here. EPA must therefore make clear both the timeline and process for EPA to determine the final status of these plants.

XIII. EPA Is Properly Taking Action to Develop Standards for Modified and Reconstructed Sources.

A. Modified Sources

Section 111 directs EPA to set standards of performance for "new sources," 42 U.S.C. § 7411(b)(1)(B), which are defined to include modified sources. *See id.* § 7411(a)(2) ("The term 'new source' means any stationary source, the construction *or modification* of which is commenced after the publication of [the final or proposed NSPS] . . . .") (emphasis added). *See also* 40 C.F.R. § 60.1(a). Section 111 further defines "modification" as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4). In the current proposal, "EPA is not proposing standards of performance for modified or reconstructed sources." 79 Fed. Reg. at 1433. However, we are aware that EPA recently submitted to OMB a draft rule establishing CO_2 NSPS for modified and reconstructed fossil fuel-fired EGUs, with plans to publish the rule by June of this year.[411] Joint Environmental Commenters acknowledge and appreciate EPA's efforts to

[409] *See* Sierra Club *et al.*, *supra* n. 200 at 87-91.
[410] *See* Kansas House Bill 2636 (signed into law Apr. 27, 2014). Bill details and full language *available at* http://legiscan.com/KS/bill/HB2636/2013 .
[411] *See* EPA, Notice of Transmittal to OMB of EGU Carbon Pollution Standards - Modified Sources, http://yosemite.epa.gov/opei/rulegate.nsf/byRIN/2060-AR88, attached as **Ex. 168.**

move forward with this important set of regulations, as section 111(b) requires. Joint Environmental Commenters look forward to commenting on these proposed performance standards when they are made public.

As a policy matter, it is critical that EPA's performance standard for modified plants be sufficiently protective, since modifications may entail significant increases in carbon pollution. For example, a plant might install turbine upgrade technologies that would increase the plant's output capacity and hence its hourly CO_2 emissions; or it might initiate a boiler retubing project that would increase the boiler's area size and hence its output capacity. A plant might also undertake measures to reduce its equivalent forced outage rate and thus increase its annual generating capacity (and hence its hourly CO_2 emissions). These are the kinds of modifications to which EPA has responded with PSD enforcement actions against unpermitted plants, and EPA's forthcoming must ensure that these kinds of projects—and all source modifications—do comply with rigorous environmental standards.

We also note here that EPA's forthcoming regulations must cover *all* modifications as that term is defined in section 111, including pollution control projects ("PCPs"). EPA's current NSPS regulation specifically exempt from the definition of "modifications" any "addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial." Yet this regulatory definition does not comport with the Clean Air Act. In *New York v. EPA*, 413 F.3d 3, 40-42 (D.C. Cir. 2005), the D.C. Circuit struck down an identical PCP exemption in the context of the statute's New Source Review program. There, the court held that PCPs that increase hourly rates of pollution plainly qualify as "modifications" as that term appears in section 111(a), *see* 42 U.S.C.A. § 7479(2)(C) (cross-referencing section 111(a)), and EPA could point to no basis in the statute's context or its legislative history that should call for a differing interpretation. *Id.* at 40. Thus, the Court struck down the NSR program's PCP exemption as contrary to the Clean Air Act. As EPA acknowledged in the 2012 rule preamble, section 60.14(e)(5)'s PCP exemption is essentially identical to the provision the New York court rejected. *See* 77 Fed. Reg. at 22,421. Thus, because the PCP exemption is inconsistent with the Clean Air Act, EPA not rely on it when promulgating its performance standards for modified sources, and must ensure that PCPs are covered under the forthcoming rule.

B. Reconstructed Sources

Although the text of section 111 refers only to new and modified sources, EPA's implementing regulations properly define "reconstruction" as a type of modification. 40 C.F.R. § 60.15. That provision defines reconstruction as "the replacement of components of an existing facility to such an extent that . . . the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." *Id.* § 60.15(b). As with modified sources, EPA has exempted reconstructed sources from the proposed performance standards, *see* 79 Fed. Reg. at 1433, but presumably included them in the proposed rule it recently submitted to OMB. Again, Joint Environmental Commenters appreciate EPA's efforts to move forward with these regulations.

Performance standards for reconstructed sources are particularly important; without them, an operator wishing to construct a new plant could simply take an existing facility, demolish everything but a few parts, and then construct a new plant in its place. According to section 60.15(b)'s definition, this would constitute a "reconstruction," and the absence of regulations for reconstructed sources would permit this effectively new facility to escape the new source standard entirely. Under these circumstances, the loophole would permit what is for all intents and purposes a brand new power plant to "increase emissions without application of [BSER]," 75 Fed. Reg. at 54,996, a scenario that is clearly contrary to the goals of the Clean Air Act. Accordingly, it is wholly appropriate that EPA's rule for modified sources will cover power plant reconstructions as well, and Joint Environmental Commenters look forward to reviewing this rule upon its publication.

XIV. The NSPS Established by This Rule Will Affect Future BACT Determinations Under the PSD Program

One of EPA's critical tools for regulating air quality under the CAA is the PSD program, part of the NSR process. *See* 42 U.S.C. §§ 7470-79. PSD, along with EPA's implementing regulations, seek to ensure that new or newly modified major sources of pollution do not cause significant deterioration of air quality in areas that have been designated as "attainment" with regard to one or more national ambient air quality standards (NAAQS). *Id.* §§ 7471-71, 7575; 40 C.F.R. § 51.166(a)(7). Among other things, PSD requires any new "major emitting facility" (or any major modification at an existing facility) in a NAAQS attainment zone to acquire a preconstruction permit before commencing construction, and to install BACT to reduce emissions from all "regulated NSR pollutants." 42 U.S.C. § 7475; 40 C.F.R. § 51.166(a)(7), (b)(1), (b)(2), (b)(12), (b)(48), (b)(49). Subject to the reasonable thresholds established in EPA's Tailoring Rule, *see* 75 Fed. Reg. 31,514 (June 3, 2010), "regulated NSR pollutants" include, for the purposes of PSD review, GHGs such as CO_2. *See* 40 CFR § 51.166 (b)(48)(i)-(v).

The CAA defines BACT as

> an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

42 U.S.C. § 7479(3). Unlike BSER, BACT is determined on a source-specific basis, and encompasses a broader array of considerations than those that factor into BSER. However, the statute directly admonishes that "in no event shall application of 'best available control

technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 [Section 111] or 7412 [Section 112] of this title." *Id.; see also* 40 C.F.R. § 51.166(b)(12). In other words, emission limitations established by an NSPS serve as a regulatory "floor" for future BACT determinations for facilities that fall within the same category.

It is therefore doubly important that EPA establish strong performance standards in the current rulemaking: not only are the NSPS themselves crucial for reining in dangerous CO_2 pollution from coal and gas plants, they will also lay the groundwork for future BACT determinations for EGUs subject to the PSD program. This is particularly relevant to gas plants, which will comprise the vast majority of new fossil-fired EGUs in the foreseeable future. Accordingly, Joint Environmental Commenters reiterate need for performance standards that truly reflect the cutting edge technology, and urge EPA to adopt the stricter emission limitations we have proposed in these comments.

XV. EPA Must Promptly Propose and Finalize Emission Guidelines for Carbon Pollution from Existing EGUs

Joint Environmental Commenters welcome EPA's proposal to establish the first nation-wide standards for carbon pollution from new fossil fuel-fired EGUs, but emphasize that this is only the first step in fulfilling EPA's responsibilities under the Clean Air Act and the President's Climate Action Plan. EPA must not only timely finalize these new source standards, but also promptly establish emission guidelines for existing EGUs pursuant to section 111(d) of the Clean Air Act. Reducing carbon pollution from existing EGUs is a critical priority: the power sector emits approximately 40 percent of the nation's carbon pollution, and the vast majority of this pollution will, for the foreseeable future, continue to be emitted by EGUs that were already in service at the time of EPA's proposal.[412] Moreover, the issuance of the emission guidelines is required by law: once EPA issues standards of performance for new EGUs, the establishment of standards of performance for carbon pollution from existing EGUs is a mandatory duty under section 111(d) of the Clean Air Act and EPA's implementing regulations.[413] The President's Climate Action Plan reinforced that duty by directing EPA to propose emission guidelines by June 1, 2014; to finalize those guidelines by June 1, 2015; and to receive state plans implementing standards of performance by June 30, 2016.

[412] "EIA's 2014 Annual Energy Outlook projects approximately 79 GW of fossil fuel-fired capacity additions through 2025, representing approximately 11 percent of total fossil fuel generating capacity in existence today. EIA, supra n. 108 at Table A9.

[413] *See* 42 U.S.C. § 7411(d) (providing that states "shall" submit to the Administrator state plans that establish standards of performance for any existing source that would be subject to a performance standard if it were new); 40 C.F.R. §60.22(a) (providing that EPA will publish proposed emission guidelines "concurrently upon or after proposal of standards of performance for the control of a designated pollutant" from new sources).

Joint Environmental Commenters recognize that EPA recently transmitted its proposed emission guidelines to OMB, and appreciate the agency's progress towards meeting the deadlines in the Climate Action Plan. We urge EPA to move quickly to complete interagency review of the existing source guidelines, and look forward to providing comment on those guidelines once they are made available to the public. As the Climate Action Plan recognized, the carbon pollution standards for existing power plants represent a tremendous opportunity to protect public health and the environment by leveraging clean energy solutions that have already been deployed in many states across the U.S.

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