United States Environmental Protection Agency

Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

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Comments of the National Mining Association

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GLOSSARY OF TERMS

ACI	Activated Carbon Injection
AEP	American Electric Power
APPA	American Public Power Association
BACT	Best Achievable Control Technology
BSER	Best System of Emissions Reduction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMD	Clean Air Markets Division
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule (proposed)
CBO	Congressional Budget Office
CCPI	Clean Coal Power Initiative
CCS	Carbon Capture & Storage
CEQ	Council on Environmental Quality
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CURC	Coal Utilization Research Council
DOE	Department of Energy
EEI	Edison Electric Institute
EGU	Electrical Generating Unit
EIA	Energy Information Administration
EIS	Environmental Impact Statements
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPAct05	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EVA	Energy Ventures Analysis, Inc.
FGD	Flue-gas Desulfurization
FOAK	First-of-a-kind
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GWh	Gigawatt Hour
HECA	Hydrogen Energy Project of California
IGCC	Integrated Gasification Combined Cycle
KWh	Kilowatt Hour
lbs./MWh	Pounds per Megawatt Hour
LCOE	Levelized Cost of Electricity
MATS	Mercury and Air Toxics Standards
MWh	Megawatt Hour
NACSA	North American Carbon Storage Atlas
NEPA	National Environmental Protection Act
NETL	National Energy Technology Laboratory

NGCC	Natural Gas Combined Cycle
NMA	National Mining Association
NOAA	National Oceanic Atmospheric Administration
NOAK	Next-of-a-kind
NODA	Notice of Data Availability
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standards
PM	Particulate Matter
PSI	Pounds per Square Inch (of pressure)
PURPA	Public Utility Regulatory Policies Act
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
TCEP	Texas Clean Energy Project
Tcf	Trillion Cubic Feet
TSD	Technical Support Document
UARG	Utility Air Regulatory Group
USCPC	Ultra-Supercritical Pulverized Coal

EXECUTIVE SUMMARY
COMMENTS OF THE NATIONAL MINING ASSOCIATION

In the comments set forth below, NMA extensively details the serious deficiencies with EPA's proposal to establish NSPS for CO_2 emissions from new electric utility generating sources. NMA urges EPA to seriously consider these comments and correct the deficiencies when it promulgates the final rule. Failure to do so dooms EPA's rule not only in the legal sense, but also its ability to achieve real emissions reductions and advance technology.

The proposal's fatal flaw is EPA's failure to comply with the strictures of the CAA by determining that partial capture CCS is BSER for new coal-fired units. CAA section 111(b) provides EPA certain discretion in establishing standards of performance for new sources. Importantly, however, Congress constrained EPA's standard-making authority in two significant ways by requiring every NSPS to be "*achievable*" through a system of control that "*has been adequately demonstrated*." In the proposed standard for new coal plants, EPA has failed entirely to show CCS technology is either achievable or adequately demonstrated.

Given this failure, EPA should have instead evaluated and selected technology that does meet the CAA section 111(b) criteria such as a standard based upon advanced and highly efficient coal generation technologies that are achievable and commercially available. EPA's rejection of a standard based upon advanced coal generation technologies as not resulting in "significant" CO_2 reductions is indefensible. Even the agency concedes that replacing older coal units with highly efficient new units would result in 5-20 percent emission reductions. In

fact, the emissions reductions would be twice that level if the new coal plants replace the oldest existing subcritical plants.

Instead of embracing this proven technology and adhering to the statutory requirements of 111(b), past agency practice and applicable case law, EPA determines that CCS technology is BSER for new coal units. Yet, EPA fails entirely to establish that the standard is achievable or adequately demonstrated as required under the CAA. Unsurprisingly, EPA is unable to show the standard is achievable due to the lack of actual experience with CCS systems. Because there has been no fully integrated end-to-end demonstration of CCS on a commercial scale coal base load power plant, the proposed standard lacks any credible analytical support that it can be achieved at a single plant let alone for the industry as a whole under the full range of relevant operating conditions.

Nor does EPA have sufficient data to support its conclusion that CCS is adequately demonstrated. While EPA cites several major projects in determining that CCS is "adequately demonstrated" as BSER, these projects are either under construction and not yet operational, in the planning phase and facing difficulties, or not designed to function primarily as a power plant. The lack of commercially operating facilities with real world performance data belies the demonstrated nature of these projects cited by EPA.

Further, EPA's approach to determining that CCS is BSER for new coal units deviates significantly from EPA's past precedent in determining how BSER is set. Over the last 40 years, EPA has interpreted an "adequately demonstrated" control system or technology as one that has actually been installed and operated at commercial scale for a sufficient period to ascertain its performance in the source

category. In fact, in the proposal, EPA adheres to its long-standing approach in setting the standard for natural gas combined cycle technology. The result is a standard that can be met by over 95 percent of the operating units and actually allows emission levels 20 percent higher than the levels actually achieved by the best performing natural gas units. In contrast, the proposed emission standard for coal units is at least 40 percent lower than the performance level that is achievable by these demonstrated coal technologies. EPA's standard for coal base load technology is based upon calculations for hypothetical coal units using unproven CCS technologies – a standard that cannot be met by a single existing coal base load unit, even those using the newest and most advanced technologies. Additionally, EPA's decision to require CCS for new coal units is contrary to the applicable case law, and, despite EPA's claims to the contrary, D.C. Circuit precedent do not support EPA's decision. In fact, the court has consistently held that BSER rests upon a control system that has been demonstrated through commercial application.

EPA refuses to acknowledge that CCS is equally available or unavailable for all fossil fuel-fired units and instead arbitrarily uses two distinct and irreconcilable approaches to develop standards for coal and gas-fired EGUs. CCS technology is the same fundamental system for fossil units that produce CO_2 emissions and EPA provides no rational or legally-supportable basis for the disparate treatment of coal and gas units.

EPA proffers several flawed reasons in an attempt to justify that CCS is inappropriate for natural gas-fired plants, including current emission levels, technical feasibility, adverse impacts on electricity prices, and the structure of the

electric power sector. EPA alleges that the CCS is not necessary for natural gas units because their emissions profile is already acceptably low. Simply declaring that the CO_2 emissions from natural gas are already 'acceptably low' while stating the CO_2 emissions from coal are far too high for EPA to allow is contrary to the BSER factors EPA is required to consider. Additionally, EPA studiously ignores the potential warming factors that could arise from increased natural gas production such as increased methane emissions. These emissions have the potential to overwhelm any climate benefits that EPA might be anticipating from this proposed rule and future rulemakings to control GHGs from the utility sector. Nor do EPA's claims regarding technical feasibility of CCS for gas ring true since DOE's NETL thoroughly studied the impacts of applying CCS technology to NGCC and concluded that it could be done successfully.

EPA's claims regarding adverse impacts on electricity prices and the structure of the power sector are equally unavailing, especially since these considerations bear equal weight in any finding for coal-fired EGUs. EPA bases these concerns on a faulty assumption: that all new fossil fuel-fired power will use NGCC technology and consequently, requiring CCS for all these gas-fired units would have more of an impact on the price of electricity than the few projected coal plants with CCS and the number of projects would make it difficult to implement in the short term. EPA's assumption is fundamentally flawed. EPA's projection that all new fossil fuel-fired power will be natural gas-fired holds true only so long as current market conditions do not change. If the price of natural gas climbs significantly or its availability drops in any appreciable measure then the relative price advantage that gas currently has over coal quickly evaporates. All of EPA's concerns about adverse

effect on electricity prices, electricity supplies and the structure of the power sector would be obviated with a finding that CCS **is not** BSER for any EGU (coal or natural gas).

EPA's approach risks overreliance on one power source and jeopardizes the reliability that is inherent in having a diverse energy portfolio. EPA's proposal effectively bars the construction of new higher efficiency coal base load power plants that are needed to maintain a diverse, reliable and affordable electricity supply. The centrality of coal based electricity to the reliability and affordability of the nation's electricity supply is beyond dispute. Over the past ten years, coal based electricity generation has supplied more than 45 percent of the nation's electricity supply. EPA fails entirely to consider the probability of significant price increases for natural gas. Turning a blind eye toward the inevitable is irresponsible and a costly gamble with the nation's energy future. To maintain a diverse reliable and affordable electricity grid, EPA must adopt a BSER standard that allows new higher efficiency coal units to be built.

Finally, NMA cautions EPA to proceed with great care in this rulemaking as it is merely step one of the agency's plans for regulating the power sector under the CAA to reduce CO_2 emissions. EPA has an incredibly aggressive set of regulatory deadlines to meet. These timelines are incredibly tight, giving very little time for the agency to fully consider the impacts of their upcoming proposed regulations, especially as the currently proposed rule might impact the upcoming set of proposed rules. Given that all future rules under section 111(d) of the CAA are linked to the legality and precedential nature of any sector rules proposed under CAA section 111(b), EPA needs to be particularly cautious with its current proposal.

In order to avoid unintended negative impacts on the power sector, NMA believes that EPA must pledge in the final rule that the rule will not have any impacts on modified sources that are traditionally subject to section 111(b) authority, that the proposed rule cannot set the BACT floor given its impracticability for existing and modified sources, and that EPA's technology forcing approach in the proposed rule should not (and cannot) be the philosophical underpinning for its upcoming rulemakings.

INTERESTS OF THE NATIONAL MINING ASSOCIATION

The National Mining Association (NMA) is a national trade association of mining and mineral processing companies whose membership includes the producers of most of the nation's coal, metals, industrial and agricultural minerals; the manufacturers of mining and mineral processing machinery, equipment and supplies; and the engineering and consulting firms, financial institutions and other firms serving the mining industry. It is not hyperbole to conclude that the mining industry will be one of the sectors of the economy most affected by the establishment of a standard of performance for CO_2. Because the electricity generation sector (1) contributes a large source of the nation's GHG emissions and (2) is primarily fueled by coal, proposals to reduce GHG emissions often have the purpose and effect of dramatically reducing coal usage and therefore coal mining and processing.

Nonfuel minerals and metals mining and processing will also be directly and profoundly affected by the proposed and future GHG standards of performance because these industries are highly energy-intensive. Spending on energy and

electricity by both the nonferrous metals manufacturing and metal mining sectors represents up to 30 percent of their total costs. These companies are highly sensitive to increased costs that this and further GHG regulation may create. At the same time, they do not have the ability to pass increased energy costs on to customers because metals and minerals prices are largely set in international markets, often on commodities exchanges, reflecting international supply and demand. Thus, U.S. GHG regulation, where it is not matched by foreign regulation, will create a tremendous competitive disadvantage for these companies leading to the migration of jobs, economic development and emissions overseas.

Mining is the foundation of all the trappings of modern life and a significant contributor to the American economy. Thus, the impacts of this and future GHG standards of performance on the mining industry need to be closely scrutinized. Everyday items that Americans take for granted, as well as manufactured goods vital to our national security, would not exist without mined materials. Telephones are made from as many as 42 different minerals, including aluminum, beryllium, coal, copper, gold, iron, limestone, silica, silver, talc and wollastonite. A television requires 35 different minerals, and more than 30 minerals are needed to make a computer. A military jet requires many critical minerals including titanium, nickel, cobalt and tantalum.

As EPA is aware, coal is a critical component of the nation's energy portfolio. Nearly 40 percent of U.S. electricity is derived from coal combustion. Furthermore, coal can provide substantial amounts of transportation fuels and syngas to displace significant amounts of imports of crude oil, refined products and natural gas. Notably, coal is also by far the nation's most abundant source of energy,

constituting 94 percent of the nation's fossil fuel resources. The U.S. has nearly 261 billion tons of recoverable coal reserves, according to the Energy Information Administration, which is a 240-year supply at current rates of use.

The mining industry is also a major direct and indirect source of jobs and economic development in the United States. The U.S. coal mining industry directly employs nearly 120,000 people in 23 states. For each coal mining job, an additional 3.5 jobs are created elsewhere in the economy. Additionally, about 300,000 people work directly in minerals mining throughout the United States. Employment in industries supporting mining, including manufacturing, engineering and environmental and geological consulting, accounts for nearly 1.6 million jobs. The average miner makes over $71,000 per year in salary, not including overtime, bonuses and benefits.

Additionally at risk if EPA proceeds with its desired direction is the mining industry's contribution to the national economy. Mining of coal, metals and minerals provides more than $232 billion annually in direct and indirect economic impact. According to federal statistics, the value added by major industries that consume raw materials translated into an estimated $2.39 trillion to U.S. GDP in 2012 and approximately $100 billion in coal based electricity generation.

INTRODUCTION AND BACKGROUND

On April 13, 2012, EPA proposed a greenhouse gas NSPS for new electric utility generating units that would have imposed a single emission limitation – 1,000 lbs./MWh of electrical output – on all fossil fuel-fired utility units, including

both coal-fired units and natural gas-fired units.[1] EPA recognized that – at that level – coal-fired units would be required to install CCS systems, but that natural gas units should be able to comply with existing combined-cycle technology. On June 25, 2013, President Obama released a Presidential Memorandum directing EPA to re-propose GHG performance standards for power plants by September 20, 2013, this time with separate standards for coal- and natural gas-fired units. [2]

For all practical purposes, the new standard proposed for coal-fired units did not change (rising only to 1,100 lbs./MWh) and still requires "partial CCS" in order to meet the emissions limit. EPA unwisely dismisses highly efficient generation technologies such as SCPC and IGCC, asserting those do not provide as much emissions reductions as "practicable." [3] EPA fails to acknowledge that these technologies would provide meaningful emissions reductions over the emission rates of most of the current coal EGU fleet. Moreover, EPA's reason for rejecting these advanced and highly efficient technologies cannot be squared with the proposed standard for natural gas units which set a limit that requires no reductions from NGCC units and instead allows for emissions 20 percent above the best performing units in the regulated category.

EPA attempts to justify its claims that partial CCS is "feasible" through its reliance on the following information:

(1) A literature search;

(2) Applications at industrial plants;

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[1] *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 Fed. Reg. 22,392 (April 13, 2012)
[2] *Memorandum for the Administrator of the Environmental Protection Agency*, 78 Fed. Reg. 39,535 (July 1, 2013) (also available at http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards)
[3] 79 Fed. Reg. at 1468

(3) Pilot scale EGUs in operation; and

(4) Progress towards construction of fossil fuel-fired EGUs with CCS at commercial scale.[4]

The agency's reasoning is stunningly weak, radically departs from EPA's historic interpretation and analysis in other section 111 determinations, and inexplicably ignores the context and lessons from the case law.[5] Wholly absent from EPA's explanation is *any* example of an integrated commercial scale coal-fueled EGU with CCS – with either full or partial CO_2 capture. CCS has not been demonstrated at appropriate scale for power plant application and in its current state of development it remains cost prohibitive and carries an extreme energy penalty to operate. In sum, the proposed standard is not achievable from a best system of emissions reduction that has been adequately demonstrated, and must be withdrawn. The following comments extensively detail the technical, legal and policy flaws that compel the agency to disavow the current approach and craft a rule that meets the prescriptions of CAA section 111.

COMMENTS AND DISCUSSION

I. EPA's Failure to Consider a Standard for New Coal Units that Reflects the Performance of Supercritical Pulverized Coal and Integrated Gasification Combined Cycle Technology is Unreasoned and Arbitrary

EPA asserts in its proposed rule that a new standard based upon advanced coal generation technologies such as SCPC, USCPC and IGCC generation would not

[4] 79 Fed. Reg. 1471-5

[5] See attached report, "REVIEW AND SUMMARY OF TECHNICAL BASIS USED BY EPA IN SETTING STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES," attached as Appendix 1. NMA is attaching certain key documents as appendices. All of the other reports and third-party documents NMA cites in these comments are readily available to EPA and should be considered as submitted to the record in this docket if attached hereto

result in significant CO_2 reductions and would not provide an incentive for technological innovation.[6] In contrast, EPA alleges that regulatory requirements to use CCS will promote further development of the technology. EPA is wrong and its reasoning is fatally flawed on both counts. The utility sector is able to achieve significant CO_2 reductions from building highly advanced and highly efficient coal technologies that are technically feasible and commercially available, and EPA's assertions about the proposed rule's ability to incentivize technological innovation are not adequately explained in the face of the unavailability of CCS technology for commercial power generators. Thus, EPA's decision to set CCS as BSER over other technologies that represent significant CO_2 reductions and incentivize technological innovation of efficient coal generation is unreasoned and arbitrary.

a. Advanced Higher Efficiency Coal Technologies Can Provide for Significant CO_2 Reductions

EPA readily acknowledges that SCPC and IGCC are technically feasible. More importantly, they are adequately demonstrated. Despite these facts, however, EPA dismisses these emissions reductions as providing "little meaningful CO_2 emissions reductions."[7] Yet, EPA never explains what would be meaningful reductions that are both "practicable" from the source category and actually make a material difference in global GHG concentrations for purposes of climate change.

More to the point, new higher efficiency SCPC would yield significant CO_2 reductions as compared to the subcritical technology they replace as older, less efficient units reach the end of useful economic life and retire. The most likely candidates for retirement are low-pressure subcritical units which tend to be among

[6] 79 Fed. Reg. 1468
[7] *Id*.

the older, smaller and less efficient units in the coal fleet. A comparison of the emissions performance of low-pressure subcritical plants with SCPC plants demonstrates the substantial emissions difference between these two technologies:

	CO_2 Emissions (lbs./MWh)[8]	
	Subcritical (LP)	Supercritical
Average	2,293	1,902
25P (1Q)	2,136	1,824
50P (2Q)	2,245	1,886
75P (3Q)	2,408	1,970
90P	2,527	2,087
95P	2,692	2,132

On average across all of the units examined in each technology category, a higher efficiency SCPC unit will achieve 17 percent lower CO_2 emissions than low-pressure subcritical technology. The performance gap almost doubles when comparing the best performing supercritical units with the lowest performing low-pressure subcritical units – with the best supercritical technology achieving 32 percent lower emissions than subcritical technology.

The significant CO_2 emissions reduction potential from new SCPC technology is also evident when directly comparing the recent performance (specifically, in 2013) of older plants that have announced plans to retire with newer plants of similar capacity:

[8] The data in the CO2 Emission chart was compiled from hourly emission and unit operating data for 2012 from the Clean Air Markets Division (CAMD) and other boiler design information from the EPA data base used in the MATs rulemaking. The results exclude non-operating units and units where there were data gaps. The two technology subcategories compared are: (1) Low-pressure subcritical boilers (P<1,600 psia) and (2) Supercritical boilers (P>3200 psia)

PLANTS SCHEDULED TO RETIRE	CAPACITY	FUEL	EFFICIENCY
L V Sutton Steam	604 MW	BIT	28.50%
Meramec	924 MW	SUB	29.04%
FirstEnergy Eastlake	1289 MW	BIT	29.36%
Dickerson	537 MW	BIT	29.95%
Salem Harbor	806 MW	BIT	30.05%
		AVG	29.38%

NEW PLANTS	CAPACITY	FUEL	EFFICIENCY
John W. Turk Jr.	609 MW	SUB	38.77%
Longview Power LLC	808 MW	BIT	37.10%
Cliffside Unit 6	910 MW	BIT	36.96%
Elm Road Generating Station	701 MW	BIT	35.51%
JK Spruce	878 MW	SUB	35.03%
		AVG	36.67%

Data compiled from EPA's CAMD Database, 2013

On average, the newer SCPC plants are 20 percent more efficient than the older plants scheduled to retire – a significant improvement. Furthermore, the newest plant – AEP's John W. Turk, Jr. unit, which uses subbituminous coal – is 36 percent more efficient than the LV Sutton Steam plant, which is of comparable size and burns bituminous coal.

Since most of the current coal-fired EGU fleet is comprised of subcritical technology, a migration to new, higher efficiency SCPC technology would produce

real emissions benefits. EPA should not foreclose the opportunity of higher efficiency coal units to replace older, less efficient units. There is no question that the lower emissions profile of SCPC technology is real, substantial and well-documented. Further, new base load EGUs will be needed to replace the plants that have already retired and those that will retire over the next decade due in no small part to previously finalized EPA regulations. EIA forecasts that about 60,000 MW of coal-fired capacity will retire by 2020.[9] Other experts forecast a similar level of potential retirements in the range of 59,000-77,000 MW in the same time period – in other words, roughly 20-25 percent of coal base load capacity.[10]

Over the past four years, more than 43,000 MW of the nation's electricity generating capacity (coal, natural gas, oil, nuclear and hydro) has retired, and almost 230,000 MW of the remaining capacity is presently forty years or older. These trends clearly demonstrate both a need and opportunity to replace it with higher efficiency SCPC and IGCC technology that will ensure that the nation's electricity supply remains diverse, reliable and affordable. The proposed standard for new coal-fired EGUs effectively bans new coal base load power that will be absolutely necessary to maintain the attributes and advantages of a diverse, reliable, secure and affordable electricity system in the United States.

b. The Proposal Embodies an Arbitrary and Unreasoned Approach for Setting Standards

[9] EIA, AEO2014 Projects More Coal-Fired Power Plant Retirements by 2016 Than have been Scheduled, http://www.eia.gov/todayinenergy/detail.cfm?id=15031
[10] See, e.g., Brattle Group, Potential Coal Plant Retirements: 2012 Update (Oct. 2012) at http://www.brattle.com/system/news/pdf2s/000/000/095/original/Potential_Coal_Plant_Retirements_-_2012_Update.pdf?1377791286

EPA quickly dismisses as insufficient the improved emission rates from supercritical and IGCC as compared to the subcritical technology that dominates the coal-fueled EGU fleet. Under EPA's proposed limits, new coal plants would need to meet a limit 40 percent below the emissions performance of the best advanced supercritical plants. However, EPA takes an entirely different approach for natural gas base load plants. EPA forgoes seeking "as much emission reduction as practicable," and instead sets a standard which allows emissions from new natural gas-fired plants that are 25 percent higher than the performance of the ten best operating units. In the table below is a comparison of the proposed limits for natural gas and coal as compared to the range of performance of the ten best plants in each category over the past ten years:

Type of Unit	EPA Cited Base Load Emission Rating	Operating Range of "Best Performers"	EPA's Proposed Emissions Limit	% Difference B/t Operating Range and Proposed Limit
SCPC	1,700	1,854-1,869	1,100	-41%
IGCC	1,450	Data Limited	1,100	N/A
USCPC	N/A	1,787-1,813	1,100	-37%
NGCC	760	782-812	1,000	+25%

Data compiled from EPA's CAMD Database, accessed in 2013. Base Load Emission Rating as reflected in EPA proposed rule. All rates are presented as lbs./MWh of CO_2

The disparity in EPA's unreasoned approach can be summarized as follows:

- Natural Gas Base Load: EPA does not examine any new technology or configurations for NGCC technology. Instead, EPA looks only at the technology that "currently, virtually all new sources in this category are

using." [11] EPA examines actual performance data from existing units and selects a standard that is *higher* than "over 90 percent of small and large existing NGCC units are *currently operating*,"[12] and to ensure a level that a "NGCC facility operating in the US would be able to maintain over its life."[13] Indeed, the proposed limit is substantially **higher** than GHG BACT permit limits and base load rating emission rates in order to "take into account actual operating conditions."[14]

- Coal Base Load: EPA dismisses SCPC and IGCC technology without any examination of the actual emission improvements over subcritical technology that currently dominates the coal EGU capacity. Instead, EPA determines CCS – an unproven technology for commercial scale electricity generation— as BSER without any actual commercial scale experience or data on technical feasibility, operating performance or emissions. In short, EPA selects a standard based upon a technology that no commercial scale EGU is using and a standard that **no** currently operating coal base load unit – even the newest that began operation in the last two years – can meet.

At bottom, EPA's reasoning for its disparate approaches to coal base load and natural gas base load is a tale of "two meanings" for the same words in the statute. "Technical feasibility" for NGCC means a technology that has been deployed for well over a decade. For coal, it is not SCPC or IGCC which comprise all the new high performing coal fired EGUs that have" broken ground since 2007."[15] Rather it

[11] 79 Fed. Reg. 1485
[12] *Id*.
[13] *Id*. at 1487
[14] *Id*.
[15] 79 Fed. Reg. 1468

means a technology that certain components have been tested or demonstrated in different applications than EGUs, but never integrated into a full scale commercial operating EGU. An "achievable standard" for NGCC means one that 90 percent of the units can achieve and is 20 percent above the level achieved by the best performing units over the past five years on average. For coal it means an emission limit that has never been achieved by any operating unit or existing generation technology.

The same is true when it comes to the criteria the statute furnishes as considerations in determining whether a technology is "adequately demonstrated" and whether the standard is "achievable." For NGCC, "costs" means the status quo and rejection of more efficient but more costly generation technology; for coal-fueled EGUs it means a standard that requires technology which increases the cost of electricity generation by 70-80 percent.[16] "Energy requirements" means status quo for NGCC, but for coal-fired EGUs it means using a technology that carries a 30 percent energy penalty. Regulatory certainty for NGCC means a standard 90 percent of the operating units already achieve; for coal it means a standard that no existing operating unit can achieve and no planned or constructed unit has ever demonstrated is achievable and can be maintained over the life of the unit. Incentives for "technology innovation" for NGCC means a standard that can be met using the same technology or less by virtually all existing units in operation today; for coal it means a standard that cannot be met by the state of the art technology

[16] *Carbon Capture and Storage*, Testimony of Dr. S. Julio Friedmann, Dep. Asst. Secretary for Clean Coal, USDOE before the House Committee on Energy and Commerce, Subcommittee on Oversight and Investigations (Feb. 11, 2014)

that has been deployed recently and leaving the fate of any new coal based EGUs dependent on government assistance.

It may be true, as EPA suggests, the agency has some discretion in weighing these factors. But the manner in which the agency treats them in this proposal is clearly unreasoned and an abuse of discretion.

c. The Proposed Standard Does Not Represent the Best Technology Available

EPA's proposal discusses at length why it believes that CCS represents both BSER for new coal units and why that represents the best technology available today for new coal-fired EGUs. EPA acknowledges this to some degree in its discussion of potential rates for SCPC, USCPC and IGCC units before rejecting those as potential BSER determinations given that, in EPA's view, those options would not provide "enough" reductions to be considered BSER.[17] However, EPA is rejecting the only technology that is truly commercially and technologically available to power producers who would choose to build new coal-fired power at present or in the near future. Currently available configurations of SCPC, USCPC and IGCC plants are an understood technology that have been employed in the United States, at commercial scale, and which have available emissions data that can point to their emissions performance capabilities as commercial power producers that deliver power to the electrical grid. EPA should set standards based on real world operating data, and the only way for EPA to achieve that end would be to set emissions rates based on SCPC, USCPC and IGCC facilities – not theoretical and

[17] 79 Fed. Reg. 1468

under construction CCS plants that have yet to commence operating at commercial scale.

EPA's departure from setting BSER based on commercial operating facilities with real world operations data is a fundamental flaw in the proposed rule, as discussed at length below in these comments. BSER should be based on the best technology deployed in commercial units in operation today. Further, industry investment patterns in new coal also bear out that SCPC, USCPC and IGCC plants are the most logical technological progression for new coal units, and EPA's jump to requiring CCS represents a bridge too far in setting BSER. The CAA allows EPA to constantly revise NSPS standards every eight years, at a minimum, in order to better reflect technological advancements that occur in the real world – indeed, the ability to capture technical advancements in the generation of power is one of the fundamental bedrocks of the Act itself. If and when CCS technologies are adequately (i.e., reliably) demonstrated for commercial operation at base load power plants, EPA could then revisit BSER and set an emission limit. Thus, the agency's decision to jump forward and establish NSPS based upon CCS now, without demonstrable CCS technology available for base load commercial operation, is both unprecedented and unlawful.

d. BSER and an Achievable Emissions Standard Should be Based on the Best Technology at Commercial Units in Operation Today

EPA has a statutory obligation to set achievable emissions limitations when determining appropriate levels in any NSPS. BSER should be set based on units in operation today as commercial power producers. Relying upon real world operating data is the proven, lawful, and prudent way to determine what a BSER could be

that has been adequately demonstrated. In this proposal, EPA has done so for natural gas-fired but not coal-fired EGUs. The operations data from the best performing coal and natural gas plants provides the minimum data to set achievable standards. Had EPA relied on actual operating data in its determination of BSER for both coal and natural gas units, as opposed to its attempt to force the requirement of CCS technology on only coal units, it would have come to a vastly different conclusion on what BSER could be and thus what emissions limits would be achievable.

i. Review of Natural Gas Best Performers

EPA's BSER analysis for natural gas units (setting BSER as NGCC combustion systems) follows the historic approach by EPA by relying upon an analysis of the best performing natural gas units in operation today based on real world operating data and provides for significant operational flexibility and the potential for NGCC units to far exceed the operational capabilities of those best performers. Data retrieved from EPA's own CAMD database provides the performance capabilities of these NGCC units in commercial operation:

Summary of CO_2 (lbs./MWh) Best Performing NGCC Units (2008-2012)

ORIS	Utility	Plant	Unit ID	CO_2 (lbs./MWh)
055464	Deer Park/Calpine OSC	Deer Park Energy Center	CTG4	782
055464	Deer Park/Calpine OSC	Deer Park Energy Center	CTG1	785
055464	Deer Park/Calpine OSC	Deer Park Energy Center	CTG3	789
055217	Los Medanos Energy Center LLP	Los Medanos Energy Center	X724	801
050006	PurEnergy LLC/Pittsfield GC	Pittsfield Generating	004001	802
055217	Los Medanos Energy	Los Medanos	X725	802

	Center LLP	Energy Center		
055123	Calpine OSC	Magic Valley Generating Station	CTG-2	805
055047	Pasadena Cogeneration/Calpine OSC	Pasadena Power Plant	CG-1	811
007721	Alabama Power Company	Theodore Cogeneration	CC1	812
055075	Pine Bluff Energy/Calpine OSC	Pine Bluff Energy Center	CT-1	813

Source: EPA CAMD Database, accessed November, 2013

This review of the best performing NGCC units operating between 2008 and 2012 reveals that over that five year period, NGCC units operated between 782 and 813 lbs. CO_2/MWh. In the proposed rule, EPA states that:

> To further evaluate the impact of the proposed rule we reviewed the GHG BACT permits for eight recently permitted NGCC facilities. Of these facilities, seven are larger than 850 MMBtu/h, and one is smaller. The seven larger facilities all have emission rates below 1,000 lb/MWh, and as low as 880 lb/MWh. The single smaller facility, which is 400 MMBtu/h, has a permitted emissions rate of 1,100 lb CO2/MWh. The GHG BACT permit limits are higher than the base load rating emissions rates *because they take into account actual operating conditions*.[18]

EPA's review of BACT permits is analogous to the operational data pulled directly from CAMD, as cited above. That data shows that NGCC units can operate, when performing as base load units in peak conditions, at levels *far below* EPA's proposed 1,000 lbs. CO_2/MWh standard for those units. Therefore, not only has EPA proposed a standard under Subpart KKKK that can be met by NGCC units when

[18] 79 Fed. Reg. 1487 (emphasis added)

taking into account flexible operational conditions, but EPA has also allowed those units a 20% "cushion" above their operational capabilities at peak.

ii. Review of Coal Best Performers

A similar BSER analysis of the best performing coal units in operation today based on real world operating data would, like the approach used for NGCC, produce an achievable standard while also yielding better emissions performance from the coal-based EGU fleet. Data retrieved from EPA's CAMD database provides a much more realistic portrait of the performance capabilities of the top performing coal units in commercial operation than the base load emission "estimates" cited by EPA in the proposed rule. A review of the available data shows that EPA's BSER determination, and also its discussion of highly efficient coal units, is legally insufficient.

The majority of commercially operating coal-fired power plants are subcritical pulverized coal units, which operate at steam pressures below 3200 psi, with units operating above 1600 psi considered to be high pressure subcritical units. SCPC units and USCPC units operate at much higher steam pressures, and are as a result, designed to be more efficient.[19] Excluding the subcritical units, a review of the best performing SCPC units operating between 2008 and 2012 reveals that over that five year period, SCPC units operate between 1,854 and 1,869 lbs. CO_2/MWh. This data is pulled directly from CAMD's database, excluding MDS and bias adjusted data for units in annual operation greater than 50% of the time annually, excluding common stack units:

[19] IGCC units are a separate category, and are relatively newer construction and are not included here in this analysis. However, their performance characteristics are also available in CAMD's database, but in a more limited sense

Summary of CO_2 (lbs./MWh) Best Performing SCPC Units (2008-2012)

ORIS	Utility	Plant	Unit ID	Boiler Type	CO_2 (lbs./MWh) PC – All
003118	GenOn	Conemaugh	2	SCPC	1,854
003118	GenOn	Conemaugh	1	SCPC	1,857
003136	Pennsylvania Power & Light	Keystone	1	SCPC	1,867
008042	Duke Energy	Belews Creek	1	SCPC	1,868
003149	GenOn	Montour	2	SCPC	1,869

Source: EPA CAMD Database, accessed November, 2013

GenOn's Conemaugh facility (units 1 and 2), Pennsylvania Power & Light's Keystone facility, Duke Energy's Belew Creek unit and GenOn's Montour plant represent that best performing SCPC units and comprise the best available base load operating data that EPA failed to consider in its BSER determination.

Even an analysis of the best performing units over a single year demonstrates that EPA's dismissal of SCPC technology is hasty and in error. Reviewing the best performing units from 2012, CAMD's own database shows that SCPC units operate between 1,734 and 1,811 lbs. CO_2/MWh excluding MDS and bias adjusted data for units in annual operation greater than 50% of the time annually, excluding common stack units:

Summary of CO_2 (lbs./MWh) Best Performing SCPC Units (2012)

ORIS	Utility	Plant	Unit ID	Boiler Type	CO_2 (lbs./MWh) PC – All
004078	Wisconsin Public Service Company	Weston	4	SCPC	1,734
006113	Duke Energy	Gibson	5	SCPC	1,734
003298	South Carolina Electric & Gas	Williams	WIL1	SCPC	1,758

006094	First Energy	Bruce Mansfield	2	SCPC	1,793
006113	Duke Energy	Gibson	1	SCPC	1,811

Source: EPA CAMD Database, accessed November, 2013

Clearly, the operating characteristics of SCPC units show that those characteristics vary on a year by year basis and that any standard should take those figures into account. The top five performing SCPC units in the 2012 data set are not present in the 2008-2012 data, despite several of those units being in operation throughout that time.[20] This is the result of market conditions and how much each unit is operating – some years the units run less than 50% of the time and thus do not always meet the single year emissions capabilities when operating over a number of years due to startup, shutdown, downtime for repairs and whether or not they are operating as base load plants especially in deregulated markets.

The operational data for the best performing coal-fired units demonstrate real and demonstrated improvements in emissions through SCPC as compared to subcritical plants. These improvements cannot be dismissed as inadequate or insufficient. They provide a basis for an achievable standard.

iii. EPA's Proposed BSER Should Reflect Operational Realities

Given the operational data available on actual best performing units, EPA should therefore set those technologies as BSER and calculate achievable emissions rates based on those best performing units (while also including operational flexibility for startup, shutdown, load following and other concerns). As stated previously, and drawn out in the review of data, the estimates from DOE/NETL cited

[20] All units were operational throughout 2008-2012

by EPA are not enough to justify a BSER standard. EPA is obligated to perform a thorough review of the operational capabilities of the best performing units, similar to the review EPA references that it conducted for NGCC facilities in setting BSER for Subpart KKKK.[21] EPA's cited emissions rates for conventional non-CCS coal units are still too low given operational realities, and should be set at a minimum between 1,800 and 2,000 lbs. CO_2/MWh, while the emissions rates for NGCC units should be further reviewed given the wide margin of safety built in to EPA's proposed standard.[22]

II. The Proposed Standard is Arbitrary and Capricious Because it is Not Achievable by Any System of Emissions Reduction That Has Been Adequately Demonstrated

The proposed rule is not only a "rush before ready" in terms of technology, but also a misuse of CAA section 111(b) since it does not accurately reflect the statutory requirements the law prescribes to the agency. EPA's decision to require partial capture CCS technology and thereby set an NSPS that is not achievable by any demonstrated system of emissions reduction is arbitrary and capricious.

a. The Requirements of CAA Section 111(b)

The CAA carefully prescribes the development of performance standards under section 111. Specifically, section 111(b) of the CAA requires EPA to prepare a list of source categories that, in the judgment of the Administrator, cause or significantly contribute to air pollution that may reasonably be anticipated to

[21] 79 Fed. Reg. 1486
[22] EPA could also choose to set the proposed standard based upon operational conditions only at full load in order to incentivize efficient units using net output standards without including startup and shutdowns which impair CO_2 performance, as discussed later in NMA's comments

endanger public health or welfare.[23] Then, for every source category on that list, EPA must establish "standards of performance" for "new sources," commonly referred to as NSPS. EPA is not free to establish the performance standard at any level it desires. The statute specifically requires EPA's performance standard to:

> Reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which … the Administrator determines has been adequately demonstrated.[24]

The statutory text and EPA's historic interpretation of CAA § 111 set forth a "bottom up" framework that includes three core steps:

- First, determine BSER that has been adequately demonstrated for all sources within the source category considering the cost of installing and operating the control system as well as the nonair quality health and environmental impacts and the energy requirements of the technology or system;
- Second, calculate the degree of emissions reduction that is achievable through the application of the BSER including any adjustments to reflect the ability of sources to achieve the emissions reductions under the full range of operating conditions by all sources within the source category. In this case that would include adjustments to the control level in order to reflect what can be achieved on a consistent basis for a broad range of boiler and coal types.

[23] 42 U.S.C. § 7411(b)
[24] 42 U.S.C. § 7411(a)(1)

- Third, formulate a specific performance standard (numeric emission limit, averaging time, and monitoring) that may be achievable by all sources within the source category.[25]

The "bottom up" process for setting NSPS standards differs substantially from the "top down" approach for setting emission limits under the NSR permit program. Most importantly, the NSPS is a nationwide performance standard that applies to all sources and the emission limits must be achievable by all types of sources within the source category under a broad range of operating conditions. BACT limits, by contrast, are established case-by-case for a particular source for inclusion in the NSR permit. A BACT limit need not be feasible for other similar sources in the category.

In the current proposal, EPA has reached a stunningly wrong determination of BSER. This fundamental flaw prevents EPA from satisfying the other steps in determining the degree of emission reductions that are achievable or formulating a specific standard that can be met by **any** — let alone all — sources within the source category. As EPA has explained, a NSPS must be grounded in "the best system of continuous emissions reductions that has been demonstrated to work in a given industry [and] currently in use within that industry."[26] Despite EPA's repeated assertions to the contrary, CCS is neither demonstrated to work nor currently in use at scale within the electric power sector for coal-fired base load power generation.

b. EPA's BSER Determination is Incorrect and Unlawful

[25] *Id*.
[26] See EPA Statement on New Source Performance Standards, available at http://www.epa.gov/region9/air/listening/BackgroundEstablishingNewSourcePerformanceStds.pdf

While EPA is afforded discretion by the CAA in establishing standards of performance for new sources under CAA section 111(b), this discretion is not absolute. The CAA places important bounds upon EPA's standard-making authority. As succinctly described by the DC Circuit, the bounds on that authority are that the *system* must be *adequately demonstrated* and the *standard* must be *achievable*.[27]

Here, EPA inexplicably adopted a standard of emissions reduction based upon a system (CCS) that has undergone no demonstration whatsoever — let alone adequately — for commercial-scale coal base load power plants. As a result, the proposed standard cannot be achieved: the lack of actual experience with CCS systems on coal base load power plants makes it impossible and impractical to discern what emission level is reasonably achievable under a full range of expected operating conditions.[28]

i. CCS Is Not "Adequately Demonstrated" or Available at Reasonable Cost for Commercial Scale Coal Base Load Power Plants

CCS technologies are not adequately demonstrated for commercial coal base load power plants. EPA's determination that CCS meets the meaning of "adequately demonstrated" is technically and factually wrong as well as unprecedented. CCS includes four primary steps: CO_2 capture, compression, transport and storage. Everything about CCS – the quantity of material captured from the gas stream, the number of individual process steps, the volume and pressure of the byproduct to be managed, the transport distance and securing the

[27] *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (emphasis added)
[28] This comparison is embedded in EPA's proposed rule at 79 Fed. Reg. at 1487 (relying on actual operating data to set a standard for new NGCC units above the level that 90% of existing NGCC of all sizes actually performs), in direct contrast to 79 Fed. Reg. at 1470 (relying on a NETL paper on IGCC with CCS to set standard for all new coal units)

long term fate of the byproduct – represent multiple increases in complexity and scope relative to any previous emission control system. Meaningful experience is absent from the three evolving CO_2 capture technologies – post-combustion, pre-combustion and oxy-combustion. Carbon storage or sequestration also remains uncertain with barriers to long term sequestration that must be addressed including mapping subsurface geology, site characterization and property rights.

While EPA relies upon pilot plant demonstration projects and applications in other industries for the various components of CCS, there has been no integrated process operated at commercial scale for electric power generation. Before CCS can be reasonably determined to be BSER for CO_2 emission reduction, additional experience is needed from demonstration projects that will allow for the design of commercial-scale EGUs for different coals. The results from existing pilot projects and demonstrations must be scaled up to a commercial size (500 MW and greater) and operated for a sufficient period to assure the components work not just individually, but reliably in a system at large scale while meeting a variable load as required for commercial operations.

Satisfying variable load requires not a collection of components but a fully integrated system in which the CO_2 control processes can respond with the rest of the plant to meet a variable, and at times unpredictable, operational load. The success of individual components at small sizes or scale in singular applications – while promising – does not equate with success in demonstrating an integrated design. This is a fundamental point ignored by EPA, yet recognized by experts in the CCS technology development:

- Global CCS Institute: "[T]he key technical challenge for CCS deployment is the integration of component technologies into successful large-scale demonstration projects in *new* applications such as power generation."[29]
- International Energy Agency: "[A]lthough the individual component technologies required for capture, transport, and storage are generally well understood...the largest challenge for CCS deployment is the integration of component technologies into large-scale demonstration projects."[30]
- DOE: "First-generation CO_2 capture technologies are currently being used in industrial applications. However, in their current state of development these technologies are not ready for implementation on commercial coal-based power plants because they have not been demonstrated at appropriate scale, require approximately one-third of the plant's steam and power to operate, and are cost prohibitive." [31] DOE's technology roadmap has set an aspirational goal of "having an advanced CCS technology portfolio ready by 2020 for large-scale demonstration that provides for safe, cost effective carbon management."[32]

In light of the facts and expert opinions regarding the current status of this emerging technology, EPA provides no reasoned rational explanation how they can

[29] *The Global Status of CCS: 2013*, Global CCS Institute, p. 10
[30] *Technology Roadmap: Carbon Capture and Storage: 2013 Edition*, The International Energy Agency, 2013, p. 5
[31] DOE, National Energy Technology Laboratory, available at http://netl.doe.gov/research/coal/carbon-capture
[32] *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap*, Dec. 2010, p. 3

determine CCS technology "has been adequately demonstrated." EPA's proposed determination that CCS is adequately demonstrated for coal-fueled power plants is based upon disparate examples that either do not provide relevant, or authentic, experience for dedicated power generation or remain in construction or design phase. The disparate examples include demonstrations of single components, small industrial units not engaged in wholesale power generation, small scale pilots, projects that operate intermittently or projects that do not involve the full scope of a CCS system. EPA's explanations of why CCS is adequately demonstrated frequently shifts between discussions of post-combustion, pre-combustion and oxy-combustion as if the experience from one technology can be readily applied to another despite the fundamental differences in the process steps. As discussed extensively below, this is not the case.

1. Post-combustion CO_2 Capture Systems

Post-combustion CCS capture technology is quite different from pre-combustion capture systems, although it is fundamentally similar in its lack of commercial availability. CO_2 capture from combustion products requires a chemical reagent with a strong affinity for CO_2. Capture processes are based on chemical absorption, physical adsorption, or gas permeation, with each approach offering different advantages and disadvantages. Work to date suggests processes based on chemical absorption are closest to commercial feasibility, although work continues on alternatives.

The captured CO_2 must be regenerated into a CO_2-rich stream with post-combustion capture systems. Amine-based systems, specifically systems utilizing mono-ethanol amine, have received considerable attention for utility application.

However, the large amount of energy required in regenerating CO_2, and the extensive number of process steps required, challenges the commercial viability of such processes. The parasitic energy burden of amine-based post-combustion CO_2 control is significant. A conventional pulverized coal-fired plant equipped with FGD for SO_2 control and SCR for NO_x control will devote 5-6% of the plant output to the environmental control system. By way of contrast, post-combustion CO_2 control for a comparable new unit will consume **more than 19%** of the gross plant output. As a consequence, the net thermal efficiency of power generation for a new unit decreases from 39.1% to 27.2% (for a supercritical boiler). While a small amount of experience exists with post-combustion CO_2 capture using mono-ethanol amine and similar reagents (such as at AEP's mountaineer project and Plant Barry), it is limited to small-scale installations or intermittent capture scenarios. Given the lack of full scale, commercialized, constantly operating post-combustion CCS capture facilities, broad commercial deployment of post-combustion carbon capture cannot be reasonably anticipated to be a demonstrated option until 2020 at the earliest.

EPA's examples of operating post-combustion carbon capture are comprised principally of small coal-fired boilers with a very small slip-stream capture of CO_2 with the CO_2 used for commercial purposes such as food or chemicals:

- AES/Warrior Run: A 225 MW coal unit that provides a 12 MW-equivalent CO_2 slip-stream (6% of capacity) for food processing at an adjacent site. This plant provides no relevant experience in terms of amount of material captured or its transport or storage given the small slip-stream and minimal usage in the adjacent site.

- AES/Shady Point: Similar to Warrior Run except even smaller with a 7 MW-equivalent slip-stream of CO_2 (or 4% of capacity) for food processing as a secondary process. Again, this facility provides no relevant experience in terms of amount of material captured or transport and storage.
- Searles Valley Minerals: A small 27 MW coal boiler with CO_2 captured from the flue gas for mineral processing. This is not an electric generating unit, but a unit designed and operated for on-site processing of soda ash.

EPA also references two test pilot projects. Both use different processes and capture technology and they only capture small fractions of CO_2 as compared to the requirements of a commercial scale power plant:

- AEP/Mountaineer: 20 MW pilot plant using Alstom's chilled ammonia process operated for 30 months capturing the small total of 15,000 tons of CO_2 stored in a nearby saline aquifer within the plant's boundaries.
- Alabama Power/Barry: 25 MW pilot plant demonstration of an amine–based technology that removes approximately 500 tons of CO_2 per day from flue gas, transports the material 12 miles and stores it in a saline aquifer. Permanent sequestration was initiated in August 2012 and is scheduled to continue through 2014 with monitoring of the storage site scheduled through 2016.

The only electric power generation project incorporating carbon capture and reuse for EOR remain under construction or at the preliminary engineering study stage:

- Sask Power/Boundary Dam: Retrofit of a 110 MW unit anticipated to capture 1 million tons of CO_2 per year as part of a combined CO_2 and SO_2 control process. The Canadian national government is providing 18 percent

(approximately $240 million U.S.) of the $1.35 billion project costs. The plant is not expected to become fully operational until later in 2014, and recently announced that it had to delay operations due to technical difficulties.[33]

- W.A. Parish: Retrofit of a 240 MW-equivalent demonstration project designed to capture 1.65 million tons of CO_2 for EOR. DOE is providing 49 percent of total project funds.

2. Pre-combustion CO_2 Removal Systems

Pre-combustion capture CCS technology is fundamentally reliant upon the gasification process of coal into syngas for use in syngas turbines, specifically utilized by IGCC units. IGCC units deploy both the Brayton (combustion turbine) and Rankine (steam turbine) cycles to derive a higher thermal efficiency, contributing to a lower CO_2 output per unit of generating capacity in comparison to pulverized coal processes. IGCC technology converts carbon-based fuels into a clean mixture of mostly carbon monoxide and hydrogen, referred to as syngas. The syngas is cleaned of sulfur, particulates and other contaminants prior to being fired in a combustion turbine for power generation. The CO_2 can be removed from the syngas – hence its status as a "pre-combustion" removal technology, and can be integrated with syngas production. Pre-combustion CO_2 capture entails adding process steps to (a) "shift" the energy from carbon monoxide to hydrogen, (b) remove CO_2, either with sulfur compounds or in a separate process, and (c) compress the collected CO_2. The primary energy-containing product after the "shift" is hydrogen, which is fired in combustion turbines. Pre-combustion CO_2

[33] "SaskPower says unexpected findings have delayed carbon capture project," The Canadian Press, available at http://www.680news.com/2014/02/20/saskpower-says-unexpected-findings-have-delayed-carbon-capture-project/

removal exploits the high operating pressure of gasification to enable physical adsorption of CO_2 by a reagent. Consequently, CO_2 evolves at pressure well above ambient (75-150 psi) which reduces the compression required for pipeline transport.

IGCC equipped with CO_2 removal has yet to operate in an integrated system for power production. Although several chemical plants in the U.S. use gasification with CO_2 recovery, none are primarily designed for power generation as base load operations. Several IGCC units equipped with pre-combustion CO_2 removal and designed for power generation have been proposed but only one is under construction, which is the Kemper County Facility as cited by EPA in the proposed rule. Research to improve pre-combustion CO_2 removal at IGCC units is mostly directed to improve process reliability and availability, with a near-term focus on seeking new solid phase sorbents that will simplify the water gas shift reactions which has the potential to improve reliability and availability. Examples of these solid sorbents are salts that are liquid at room temperature that absorb large amounts of CO_2, particularly at high temperature, which enables their use in warm gas clean-up processes. Given the uncertainties in present state-of-art IGCC, broad commercial deployment with carbon capture cannot be reasonably anticipated to be a demonstrated option until 2020 at the earliest.

The pre-combustion projects examples cited by EPA are in design-phase, under construction, or do not produce wholesale electricity generation:

- Great Plains Synfuels Project: This is not a utility application of pre-combustion CO_2 control, since the Great Plains Synfuel Project produces chemicals and not power. The primary product is pipeline quality synthetic

natural gas. The plant also produces commercial quantities of ammonium sulfate, anhydrous ammonia, cresylic acid, naphtha, phenols and tar oil. The captured CO_2 (65%) is used for an EOR project in the oil fields of Weyburn, Saskatchewan, Canada. The plant was originally constructed as a DOE demonstration project of synthetic fuels, and received a $2 billion loan guarantee and other federal support since its inception 30 years ago.

- Kemper County/Mississippi Power: Kemper County is a 582 MW electricity plan using adjacent lignite coal in a Transport-Integrated Gasifier designed to capture 65% of the CO_2 and transport it for EOR at partially depleted oil fields. The plant remains under construction with the latest project schedule forecasting commercial operation in the fourth quarter of 2014. The DOE is providing some $270 million in grant funding to support this demonstration project, and overall costs have surpassed $5 billion. Although EPA touts this project as supportive of their determination that CCS is an adequately demonstrated technology, the owner and developer of the project, Southern Company, rejected this position in testimony before the EPA:

  > "EPA justifies stringent new coal-fired power plant standards by referencing four facilities that are planning to implement CCUS. None of these facilities, including the Kemper County energy facility, are currently commercially operating, and further, two of the projects are not yet under construction. Clearly, the referenced facilities have not adequately demonstrated CCUS and the re-proposed standards should not rely on them. Furthermore, the Kemper County energy facility is a first-of-its-kind DOE co-funded project which will demonstrate

Transport Integrated Gasification, or TRIGTM technology, and the integration of advanced syngas cleanup. In developing the technology, Southern Company and DOE have agreed to jointly evaluate the facility for a four-and-a-half-year period after it begins operation. While the Kemper County energy facility marks a significant technological milestone, it is only a first step in the integration of one type of carbon capture technology with a specific generation technology. Experiences gained from the Kemper County energy facility, as well as from many more fully integrated applications of CCUS on full-scale power plants, are needed before the technology can be considered adequately demonstrated. In addition, the location of the Kemper County energy facility, which is close to its fuel source and existing CO2 pipelines, makes the facility the right choice for Mississippi and other parts of the country that share these common characteristics. However, due to its many site-specific characteristics, the Kemper County energy facility cannot be consistently replicated on a national level and should not be used in developing a national standard for greenhouse gases."[34]

- Texas Clean Energy Project: TCEP is a 400 MW IGCC generating unit designed to capture 90% of CO_2. The project has not begun construction and the 25-year power purchase agreement for 200 MW expired at the end

[34] Testimony of Mr. Danny Herrin, Environmental Affairs Director for Southern Company, before EPA public hearing on New Source Performance Standards for New Power Plants, Washington, DC February 6, 2014

of 2013 without prospects for a new purchaser. DOE has provided $450 million of the $2.4 billion investment.

- Hydrogen Clean Energy Project of California: HECA is an IGCC fueled by residual fuel oil and petroleum coke to generate 250 MW of power while producing hydrogen and fertilizers. Designed for approximately 90% CO_2 capture, the captured CO_2 will be used for EOR in nearby oil fields. The plant has not begun construction and would not likely operate until four years after construction is complete. Approximately $440 million (roughly 11%) of the $4 billion project cost has been funded by DOE.

3. Oxy-combustion Systems

Oxy-combustion requires the firing of coal in a nearly-pure oxygen environment utilizing the same steam-based Rankine thermodynamic cycle as conventional pulverized coal-firing, but eliminating the nitrogen – leaving solely oxygen as the media supporting combustion. Oxy-combustion produces a low volume, high purity CO_2 stream requiring minimal processing. Boilers designed to fire as oxy-combustion must be designed and operated to recirculate combustion products to maintain the gas velocities that enable steam production. The combustion products, dominated by CO_2 content, will also contain trace constituents of sulfur, mercury, and NO_x derived from the fuel. Experience with flue gas SO_2 concentrations of 3,000 ppm in conventional coal-firing suggests corrosion can be a problem; the presence of up to 8,000 ppm SO_2 in a nearly exclusive CO_2 gas stream could exacerbate corrosion at the turbine. Operating experience with oxy-combustion is mainly limited to test facilities, most notably the Vattenfall project in Germany. The most significant challenges for oxy-combustion based on

conventional cryogenic processes are scale-up and reliability, and the auxiliary power penalty. The auxiliary power penalty negates any cost advantage of oxy-combustion over post-combustion CO_2 removal. A new unit with a desired output of 550 MW must therefore be designed for a gross capacity of 793 MW to accommodate the nearly 31% auxiliary power penalty.

Additional and ongoing research in oxy-combustion is directed to determining the required materials of construction for boiler and heat transfer surfaces, combustion characteristics in an exclusive oxygen environment, the production of byproduct gas constituents, and improving oxygen separation. Advanced oxygen separation methods are being explored, including, among other concepts, ion transport membranes, oxygen transport membranes, special membranes, and sorbents based on the principles of temperature swing adsorption and pressure swing adsorption. These potential low energy means to separate oxygen for fuel firing represent long-term research and development activity. While these options are possibly of great import in the future, they are extremely unlikely to contribute to oxy-combustion applications within the foreseeable future. As such, oxy-combustion, while a promising avenue for CCS technology, remains unavailable for commercial application today.

One pilot plant test program was completed in the US as a precursor to FutureGen 2.0 project and provides only preliminary data at small scale and limited operations:

- FutureGen 2.0: This single demonstration of oxy-combustion technology is a retrofit of a 167 MW unit. The project is currently finishing final engineering design in 2014. Like most first-of-a-kind CCS projects, it faces two unique

commercial gaps: (1) capital premium; and (2) operating premium. The $1 billion federal government funding will close some – but not all – of the entire capital premium. The coal industry and other partners have provided significant capital investment in the project. A specific state law providing for a certain amount of electricity from clean coal projects provides a mechanism to close part of the operating premium. The project schedule has operation commencing in October 2017 contingent on the following: securing commercial financing; beginning plant construction in summer of 2014; completion of pipeline and CO_2 storage site by fall 2015 and completing construction of the power plant by the spring of 2017.

At this stage, there are only several research and demonstration projects underway to determine if CCS can be scaled and commercialized for the application to wholesale power generation. The "technical feasibility" of discrete components of a complex CCS control system does not equate to "adequately demonstrating" the entire system as an integrated process for the intended application—in this case wholesale power generation. These systems employ up to 125 separate subsystems that have never been operated as one integrated design that exclusively serves power generation.

The large-scale demonstration projects necessary to gain relevant experience for commercial deployment have not commenced operation to measure performance and reliability for any of the three carbon capture methods: pre-combustion (Kemper); post-combustion (Boundary Dam); and oxy-combustion (FutureGen 2.0). In short, **there is no available data since none of the projects have demonstrated their ability to operate at all**, let alone

commercially. Even when these projects begin operation, the results will be limited and different in scale, scope and experience with the different coal fuel types.[35] EPA provides no reasonable or rational explanation how these projects can support a determination that CCS technology is "adequately demonstrated."

ii. EPA Has Not Properly Accounted For CO_2 Transportation and Sequestration Issues in Proposing CCS as BSER

EPA asserts that partial CCS is BSER – the best *system* of emissions reduction – for new coal fired EGUs. Yet, in making this determination, EPA only analyzes the feasibility of one component of the CCS system, carbon capture. Not only does EPA reach the wrong conclusion about whether new coal plants can meet the carbon capture requirement, EPA fails to properly account for the **entirety** of the system. The proposed standard takes no account of the transportation and storage components of CCS, which are both fundamental to reducing CO_2 emissions generated by a new source since CCS is, by nature, a complete systemic process.

EPA blithely dismisses these critical system components as outside of the regulatory process for determining BSER. For example, while conceding that "[u]nderground injection is currently the only technology available that can accommodate the large quantities of CO_2 captured at EGUs,"[36] EPA admits that "compliance with the standard of 1,100 lb CO_2/MWh is determined *exclusively* by the tons of CO_2 *captured* by the emitting EGU," and that the "tons of CO_2

[35] Boundary Dam (110 MW) and Future Gen 2.0 (167 MW) will be relatively small scale demonstrations. Kemper and Boundary Dam will dispose of CO_2 through EOR while FutureGen 2.0 will sequester it. Kemper (pre-combustion) and Boundary Dam (post-combustion) will use lignite while FutureGen 2.0 (oxy-combustion) will use bituminous coal.
[36] *Id*. at 1482

sequestered by the geologic sequestration site *are not part* of that calculation."[37] EPA further emphasizes that its proposal does not involve regulation of any downstream recipients of captured CO_2, and that the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. Regarding the existing regulatory requirements applicable to geologic sequestration, EPA affirms that they are *not* part of the proposed NSPS.[38] The proposed standard, EPA reiterates, is a numeric value that is "applicable exclusively to the emitting EGU."[39] As a result, EPA explained to its Science Advisory Board that no review of sequestration science was needed because the proposed rule "does not address carbon sequestration . . . ."[40]

In short, the proposed plants, engineering studies and literature that EPA relied upon to establish the proposed standard do not completely define the CO_2 emission reduction performance at a new source since the standard takes no account of the transportation and storage components of CCS. These issues are fundamental to EPA's definition of CCS as BSER for coal-fired EGUS, since the transportation and storage elements of CCS are both fundamental to reducing CO_2 emissions since CCS is, by nature, a complete systemic process. Since EPA has not thoroughly accounted for the ultimate fate of the CO_2 carbon dioxide produced by a new coal-fired unit, separated from the new unit's emission stream, and then transported and permanently stored, EPA's proposed NSPS is incomplete and

[37] *Id*. at 1483 (emphasis added)
[38] *Id*. at 1484 (emphasis added)
[39] *Id*.
[40] Memorandum from James R. Mihelcic to Members of the Chartered SAB and SAB Liaisons (Jan. 7, 2014) at 2, *available at* http://yosemite.epa.gov/sab/sabproduct.nsf/F43D89070E89893485257C5A007AF573/$File/SAB+work+grp+memo+w+attach+20140107.pdf

cannot be considered BSER. As discussed later in these comments, there are significant uncertainties associated with carbon storage that must be addressed. By failing to completely account for all elements of CCS, the proposed standard fails. Should EPA move forward in determining that CCS is BSER, despite the warnings and objections laid out in these comments, EPA must account for all elements of the proposal, not merely wave its hands and assert that EOR or 'other rules' can account for the transportation and storage elements of CCS. To do less would be an arbitrary and capricious application of CAA section 111(b).

c. CCS as BSER is Not Economically Feasible and EPA's Cost Estimates are Not Credible

Technology experts and utilities both agree that CCS is not adequately demonstrated to qualify as BSER. As AEP Chairman and CEO Nick Akins recently stated, "We know CCS is not ready for prime time."[41] Akins is well positioned to opine on the readiness of CCS technology since AEP conducted the discontinued Mountaineer small-scale pilot project EPA cites as evidence that CCS is adequately demonstrated.

EPA provides no reasonable or rational explanation how they can determine CCS technology has been adequately demonstrated, "taking into account the cost of achieving such reduction" as required by the CAA §111(a)(1). By any measure and by all accounts, the costs of CCS – with, or without EOR – is so exorbitant that this factor alone disqualifies the technology as BSER for coal-fired EGUs. DOE recently testified that CCS would increase the cost of electricity from a new power plant by

[41] Platts Coal Trader p. 5 (March 7, 2014) (Akins' assessment was delivered at the IHS CERAWeek 2014 conference in Houston)

as much as 80 percent.[42] Lynn Good, CEO of Duke Power, has also said that CCS is "too expensive" to consider adding it to the company's recently commissioned Edwardsport, Indiana IGCC power plant.[43] Duke Power is also well acquainted with the overly burdensome expense of CCS technologies since its Edwardsport plant was constructed to be "CCS-ready" – a factor EPA asserts indicates that CCS is an adequately demonstrated technology, despite Duke's estimation that CCS was not commercially feasible due to technology limitations and its estimation that the cost of CCS installation was too great to do anything other than build sufficient space into the design of the power plant when CCS feasibility was demonstrated and the costs became reasonable. Even further, Alstom – a global leader in the development of carbon capture technology – views CCS as not adequately demonstrated to be feasible at full scale and not cost competitive. [44]

All analyses unequivocally demonstrate that a coal-fired EGU equipped with CCS will cost substantially more to build and operate than a new state-of-the-art plant without CCS. The basic reasons are:

- The equipment for CCS required to capture and compress CO_2 is large, complex and expensive;
- Capturing and compressing CO_2 consumes a substantial fraction of the plant's electrical generation total output so the plant with CCS must be substantially larger than the plant without CCS; and

[42] Carbon Capture and Sequestration, Testimony of Dr. S. Julio Friedmann, Deputy Asst. Secretary of Energy for Clean Coal, US Dept. of Energy, before the Subcommittee on Oversight and Investigations Committee on Energy and Commerce (Feb. 11, 2014)
[43] Platts Coal Trader, p. 5 (March 7, 2014) (Good's comments were also made at the HIS CERAWeek 2014 conference in Houston)
[44] Testimony of Robert Hilton, Alstom, before the U.S. House of Representatives Committee on Science, Space and Technology Subcommittee on Energy, p. 6 (March 12, 2014)

- The substantial energy-penalty of a CCS plant will have to use more fuel for capturing and compressing the CO_2.

The substantially higher capital and operating costs in turn make the cost of electricity generated from the plant exorbitantly more expensive than that generated from a non-CCS plant.

A review of five engineering studies of the estimated costs of building and operating a new coal-fueled EGU with 90 percent CO_2 capture conclude that increases in the LCOE (adjusted to 2010 costs) range from 70-79 percent higher for a new coal SCPC plant with CCS as compared to new plant without CCS.[45] The CBO found that both the total plant costs and LCOE would increase by an average of 76 percent for a CCS equipped SCPC.[46] NETL's most recent updated costs of its baseline cases show an 82 percent cost increase for SCPC with CCS.[47] The significant and substantial increase is reflected in each cost component:

- Capital Costs: 91%

[45] Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide* p. 20 (Table A-2 Adjusted Estimates of Total Plant and Levelized Electricity Costs for New Coal-Fired Power Plants With and Without CCS Technology)(June 2012). The five engineering studies reviewed and normalized by CBO include: MIT, T*he Future of Coal* (2007); EPRI, *Updated Cost and Performance Estimated for Clean Coal Technologies Including CO2 Capture—2006* (March 2007); NETL, *Cost and Performance Baseline for Fossil Energy Plants, vol. 1, Bituminous Coal and Natural Gas to Electricity* (Nov. 2010); Carnegie Mellon University, *Integrated Environmental Control Model*, version 6.24 (May 2010); and Global CCS Institute*, Economic Assessment of Carbon Capture and Storage Technology: 2011 Update* (2011)

[46] *Id*. at 8, 17-21

[47] NETL, *Updated Costs (June 2011 Basis) for selected Bituminous Baseline Cases* p. 50 (Exhibit 5-2) (Aug. 2012). NETL's update was released after CBO's report and uses the metric Cost of Electricity (the "first year cost of electricity") which differs from the LCOE. The NETL metric COE uses a different (before tax) approach to annualizing the capital cost and uses the fuel costs for the first year of the analysis rather than for the economic life of the unit. For IGCC with CCS, NETL finds the increased COE to be 40 percent compared to IGCC without CCS. But IGCC without CCS would have a COE 25 percent higher than SCPC without CCS primarily because IGCC has a 38 percent higher capital cost than SCPC. Id. The cost comparisons for both CBO and NETL update include the CO_2 transportation and storage costs

- Fixed Costs: 40%
- Variable Costs: 70%
- Fuel Costs: 38%

It is worth noting that these cost estimates, as well as those used by EPA, are based upon engineering estimates and the learning-curve models – not on actual demonstration or commercial operating experience. These estimates are based upon "Next-of-a-kind" (NOAK) plants reflecting fully mature technology and not "First-of-a-kind" (FOAK) plants that EPA cites as evidence that CCS is BSER. In other words EPA is using incorrect values to estimate compliance costs, grossly underestimating the true cost of power generation using CCS. As explained later, it is improper for EPA to use NOAK costs for assessing the reasonableness of the costs of the technology that will be required to meet the proposed standard. However, even using the lower NOAK costs from NETL and other engineering studies **clearly** demonstrates that the cost of CCS is exorbitant and unreasonable.

Recent experience indicates that the FOAK costs will be substantially higher than anticipated and also confirms that NOAK costs in current engineering studies are too optimistic. According to an April 29, 2014 filing with the SEC, Southern Company now estimates that the Kemper Facility will now cost $5.5 billion—80 percent higher than the original $2.8 cost.[48] Real experience to date confirms that

[48] E&E News, "$5.5B Kemper carbon capture project to be delayed until 2015" (April 29, 2014). Sask Power's Boundary Dam post-combustion CCS 110 MW demonstration plant is a substitute for an earlier plan to build a new 300 MW post-combustion plant. Sask Power abandoned that plan once it realized the costs would be 150 percent higher ($1.5 billion to $3.8 billion), the technical complexity much greater, and the energy penalty substantially more ($40%) than earlier estimates - http://sequestration.mit.edu/tools/projects/boundary_dam.html. Sask Power also had concerns that the larger amount of CO2 captured from a 300 MW plant would be

the actual costs of CCS is substantially higher than the underlying engineering studies that serve as the basis for EPA's estimates set forth in the proposed rule. For example, the total overnight cost for IGCC with CCS with between 60-75 percent capture in the NETL 2012 update ranges from $1.75 billion-$1.8 billion. The *original* cost estimates for Kemper (582 MW IGCC with 65% capture) is 60-70 percent higher and the *current* cost is **185-200 percent higher** than NETL's engineering estimates.

CCS costs are excessive and unreasonable by any rational measure. The exorbitant nature of these costs, in addition to the immature state of the technology for power generation, is consistently cited as a reason by the power generation industry, governments globally and technology experts as a major obstacle to CCS deployment for commercial power production:

- DOE: There are significant costs and energy penalties associated with the application of CCS technologies in their current state of development. Significant step changes in cost and performance are required to make CO_2 capture more economically viable. Major improvements that are necessary will require more than 'learning-by-doing'; it will require new advanced CO_2 capture processes through fundamental and applied R&D to achieve improvements in both capture efficiency and costs. The majority

substantially more than the existing EOR market and the EOR revenues were essential to make the project economically feasible.

of advanced capture technology options are expected to begin to reach the pilot and demonstration stages over the next 10-15 years.[49]

- Interagency Task Force on CCS: While small demonstrations are worthwhile and important in advancing CO_2 capture technologies, they still are not at a large enough scale to overcome technical uncertainty associated with scale-up needed for cost-effective deployment. Further demonstrations by DOE are necessary to address technical uncertainties and costs.[50]
- Former DOE Assistant Secretary of Energy for Fossil Energy, Charles D. McConnell: The cost of current CO_2 capture technology is much too high to be commercially viable; it increases the cost of generated electricity by about 80 percent.[51]
- Alstom: Carbon capture "has yet to reach demonstration stages to reduce the cost and reduce the risk of scaling these technologies from pilot or validation scale to full scale."[52]

EPA's attempt to narrow the true cost gap by using NOAK instead of FOAK technology to justify CCS costs as reasonable is fundamentally wrong and lacks

[49] DOE, *CCS RD&D Roadmap* p. 24, 28. See also CBO, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide*, p. 6 (DOE analysts believe that the current technology for capturing CO2 could never meet DOE's goal of reducing the cost of CCS-generated electricity to less than 35% of cost without CCS; meeting the goal will require next-generation technologies that are 10-15 years away from pilot and demonstration stages)
[50] Report of Interagency Task Force on CCS, p. 32. Notably of all of the next projects the Task Force identifies as necessary to demonstrate CCS technical feasibility and cost-effectiveness only one is under construction, two remain in planning stages and three have been suspended or cancelled
[51] Testimony before the US House of Representatives Committee on Science, Space and Technology Subcommittees on Environment and Energy, pp. 2-3 (Oct. 29, 2013)
[52] Testimony of Robert Hilton, Alstom, before the U.S. House of Representatives Committee on Science, Space and Technology Subcommittee on Energy, p. 10 (March 12, 2014)

credible support. The proposed rule applies to any coal-fueled EGU commencing construction as of January 8, 2014, and the two plants closest to operation cited by EPA remain under construction have not even reached FOAK status. These two projects also have highly unique and situation specific characteristics which are unlikely to be replicated during the relevant time period examined by EPA. Both will use lignite produced at an adjacent coal mines. Lignite is used at mine-mouth plants; and, in the United States, this limits that technology's application to power plants located in the lignite fields of North Dakota, Texas and Louisiana and Mississippi. Lignite supplies only 5 percent of the current coal generating capacity in the U.S., and coal rank is a major factor in gasifier design and cost. As previously described, Kemper will also use a novel "TRIG" gasifier, a system that is not used on any other IGCC generating plant in the world. Boundary dam is a small subcritical design (110 MW) with post combustion capture using amine-based sorbent for CO_2 capture. A new U.S. plant would be expected to be – at a minimum – four to six times larger. Moreover, there are many different designs and capture technologies under development that use different separation principles (e.g., chemical absorptions, dry adsorption and membrane separation).

In short, EPA is justifying the costs of CCS on NOAK costs when in fact there is not even a single FOAK plant of commercial scale in operation. Further compounding this error, EPA then improperly assumes that the other plants EPA cites as "under development" (more accurately characterized as "under consideration") will use the same technology as the FOAK plants.[53] This is not likely to be the case and it is more likely that each of the next plants built will use

[53] 79 Fed. Reg. 1476

different designs to meet different needs (e.g., fuel type, generation technology and separation technology – the latter two will often be proprietary and not readily transferable).[54] Those next plants will actually be FOAK and not NOAK plants. EPA's error is further revealed in the agency's reliance on Summit/TCEP, HECA and W.A. Parish as projects that will translate into lessons learned to lower costs and support using NOAK costs for justifying a lower than reality cost estimate for CCS.[55] These are all FOAK projects that will use different designs, capture technology, fuels, disposal fates of CO_2 and co-products.[56] And they are all further out in time than Kemper and Boundary Dam from being constructed—if ever.[57]

EPA's improper use of NOAK costs was also noted by DOE and other agencies in the Interagency Review of the proposed rule.[58] Their comments and recommendations include:

[54] *See* Testimony of Dr. Richard Bajura, Director, National Research Center for Coal and Energy, West Virginia University before the US House of Representatives Committee on Science, Space and Technology Subcommittees on Environment and Energy, p. 2-3 (Oct. 29, 2013) (explaining why FOAK CCS plants have not achieved commercial status and cautioning that the next plants built will not necessarily qualify as NOAK plants given the wide range of characteristics and specific technology that must be tested and demonstrated first; so these next plants will be FOAK not NOAK). *See also* Testimony of Dr. S. Julio Friedmann, US House of Representatives Committee on Energy and Commerce Subcommittee on Oversight and Investigations (Feb. 11, 2014) (It will take two or three years before we will have a better understanding of whether the Kemper Plant is one that can be applied more broadly; most likely the US needs to have pilot projects that are not as unique as Kemper)

[55] 79 Fed. Reg. 1476

[56] In cases such as Summit/TCEP and HECA, where a plant is "power/polygeneration", the electricity may be either the smaller or one of the lowest 'value-added components of a multi-product plant (e.g., fertilizer, CO_2 for EOR, steam sold for district heating). TCEP is designed for subbituminous coal; HECA is designed to use residual oil and petcoke. W.A. Parish is a post-combustion capture retrofit on an existing plant using subbituminous coal with a co-generation NGCC facility to power CO_2 compression

[57] The Summit/TCEP power sales agreement expired Jan. 6, 2014, so TCEP will not go forward at this time

[58] *Summary of Interagency Working Comments on Draft Language under EO12866*, Docket document #EPA-HQ-QAR-2013-0495-0066

- The technology's current "first-of-a-kind" costs should be used instead of "next-of-a-kind" estimates;
- "Next-of-a-kind" costs will not be realized before more demonstration projects proceed;
- It is widely accepted among cost estimation professionals that projections of NOAK costs for technologies that are still under development are typically lower than the actual costs that are eventually realized;
- Table 6 *does not accurately portray the current cost of CCS*. The single value, "next-of-a-kind" costs current in Table 6 represent the expected costs after significant learning and demonstrations have taken place. This learning has not occurred. *We believe current cost of CCS is not accurately represented*;
- The studies from which many of the costs in Table 6 are derived are explicit regarding their level of uncertainty. Since Table 6 does not clearly present this uncertainty (-0%/+30%), *the results of the study are being misrepresented*;
- A table of cost data was provided in which the LCOE figure used by EPA was replaced by a range of values. The lower extreme of the range was the value cited by EPA, the upper extreme was 1.30 times the lower number, reflecting the uncertainty. These values are NETL's recommendation;
- The costs estimates are for plants that would precisely meet the emission limit during steady state of operation without any buffer for operational excursions and very limited flexibility to adjust the CO_2 capture rate in

response to market conditions. Plants designed for additional capture to provide a buffer and/or for flexible capture rates will cost more.

The interagency comments further demonstrate that EPA's cost methodology and estimates lack credibility and are highly speculative. Even more concerning is the appearance that EPA manipulated the methodology and estimates so the costs would appear less exorbitant and less unreasonable. Further evidence of this manipulation is found in EPA's inconsistent characterization of the type of costs it is presenting in the proposal, as EPA several times characterizes them as NOAK, but elsewhere says "they represent a plant *somewhere between* FOAK and NOAK."[59] Perhaps this is another reason why the costs set out in Table 6 do not resemble the costs set out in NETL's cost baseline studies since EPA's costs do not square with FOAK, NOAK or anything in between. EPA's efforts to obscure its cost methodology cannot shield its unsupported assertion that it is reasonable to rely on NOAK costs because the next CCS facilities can be expected to be less expensive than the current FOAK projects.[60] As explained below, actual experience in technology evolution shows that the next generation of technology will actually be more expensive and only much later upon full maturation does the cost decline.

Technology performance often degrades with scale-up. Technologies that may look promising in the laboratory or in pilot-scale tests and even demonstration scale projects often do not achieve the predicted operating performance at commercial scales – new factors arise in larger systems that were not apparent when initially tested or demonstrated.[61] As a result, the further away a technology

[59] 79 Fed. Reg. 1476
[60] *Id*.
[61] *See generally* Testimony of Dr. Richard Bajura, *supra* at p. 2

is from commercial reality, the lower the estimated costs. The Congressional Research Service aptly captured this great inherent uncertainty in its technology assessment of CCS:

> R&D programs to develop lower-cost technologies for post-combustion SO_2 and NO_x capture at coal-fired power plants…typically took two decades or more to bring a new concept (like combined SO_2 and NO_x capture systems) to commercial availability. By then, the cost advantage initially foreseen had largely evaporated: advanced technologies tended to get more expensive as the development process progressed (consistent with "textbook" descriptions of the innovation process), while the cost of formerly "high-cost" commercial options gradually declined over time. In a number of cases, the absence of a market for the advanced technology (as is currently the case for CO_2 capture systems) put it at a further disadvantage…some estimates of future electricity generation costs for advanced power plant designs with CO_2 capture and storage offer even more optimistic forecasts of potential cost reductions from advanced technologies. In general, however, the further away a technology is from commercial reality, the lower its estimated cost. Thus, there is considerable uncertainty in the projected cost of technologies that are not yet commercial, especially those that exist only as conceptual designs.[62]

[62] Peter Folger, *Carbon Capture: A Technology Assessment*, CRS Report for Congress R41325 (Oct. 21, 2013), p. 5

EPA's NOAK costs are unreasonable and cannot be squared with available information and the cost reductions DOE forecasts using the next generation of technology. EPA uses NOAK capital costs for a partial capture IGCC plant of $3732/kW.[63] The Kemper plant cost is $9180/kW, [64] which is 146 percent higher. For SCPC full capture, EPA uses a NOAK capital cost of $5005/ kW. For the Boundary Dam project (90% CO_2 capture) the capital cost is $11,300/kW, which is 125 percent higher than EPA's NOAK cost. In sum, EPA's NOAK costs assume that the next plants (1) will use the same technology and (2) will reduce the capital costs by 55-60 percent. As previously explained, the first assumption is unreasonable. The second assumption about the reduction in the capital cost is even more unreasonable. According to DOE, the next generation technologies may reduce the cost at best by one-third.[65] Most published estimates of future costs of electricity from power plants with CO_2 capture forecast a gradual decline of up to 30 percent from FOAK costs *after roughly 100,000 MW* of capture plant capacity has been installed and operated, which represents the completion of nearly 142 more Kemper and Boundary Dam style power plants. [66]

As DOE explains, the next generation technologies that may lower the costs of CCS are at least a decade away.[67] The majority of the advanced CO_2 capture technologies designed to improve the capture and compression processes to reduce

[63] Costing Analysis for Partial CCS, Memo from EPA, OAQPS to EGU NSPS Docket, Sept. 2013 (attached spreadsheet) Docket #EPA-HQ-OAR-2013-0495-0080
[64] Mississippi Power submittal to Mississippi PSC, MPSC Docket # 2009-UA-0014, Monthly Status Report through Dec. 2013 (Table 3)
[65] Testimony of Dr. S. Julio Friedman, Dep. Asst. Secretary for Clean Coal, DOE, before the US House of Representatives Committee on Energy and Commerce Subcommittee on Oversight and Investigations (Feb. 11, 2014)
[66] Peter Folger, *Carbon Capture: A Technology Assessment*, CRS Report for Congress R41325 (Oct. 21, 2013), p. 91
[67] *Id*.

the costs are still in the laboratory and bench-scale stage of development.[68] It will take more than learning-by-doing as EPA assumes to reduce these costs to the NOAK costs relied upon by EPA. According to DOE, "learning-by-doing" may result in somewhat limited improvements over time, [but] it cannot provide the significant step changes in cost and performance required to make CO_2 capture more economically viable."[69] Major improvements (such as the ones EPA assumes in its cost analysis) will require both fundamental and applied R&D in thermodynamic capture efficiency and costs.[70] In sum, EPA is improperly using costs that reflect "fully mature" technology (NOAK) when not a single FOAK plant is currently in operation and the next facilities built will still be FOAK plants. NOAK plants will not be in operation, and more likely **not even constructed**, during the 8 year time period the CAA requires EPA to revisit a NSPS based upon the state of technology and its costs.[71] EPA's approach and rationale is unreasoned.

EPA's errors in assumptions and methodology do not end with the improper use of NOAK costs to compare coal-fueled EGUs with CCS against other base load generation sources. EPA refers to NETL's cost studies as LCOE, but they are not. As explained earlier, NETL's estimates are Cost of Electricity (COE) which is the "first year cost of electricity." Converting NETL's COE estimates to a LCOE would increase the cost of the IGCC and SCPC with CCS to meet the proposed 1,100 lbs. /MWh limit by approximately 17 percent over the costs found in Table 6.[72]

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[68] DOE CCS RD&D Roadmap p. 24.
[69] *Id*. at 28
[70] *Id*.
[71] *See* comments of Karl More, Southern Company: "it isn't likely there will be a Kemper 2 built in North America in the next decade," in E&E News, "$5.5B Kemper carbon capture project to be delayed until 2015" (April 29, 2014)
[72] *See* the comments of CURC

This discrepancy is also reflected in the comparison of coal and nuclear base load generation. EPA suggests that coal with partial CCS to meet the proposed limit would have a similar LCOE as nuclear.[73] This is incorrect. The nuclear costs EPA relies upon are LCOE derived from the Energy Information Administration which is different than the COE cost estimates for coal done by NETL. Moreover, the nuclear cost estimate does not include the $18/MWh production tax credit (PTC) for generation during the plant's first eight years of operation. Since the amount of nuclear additions projected through 2040 is less than the 6 gigawatt cap on the PTC, it should be factored into EPA's cost comparison. Making those LCOE and PTC adjustments results in coal with partial CCS 36 percent more expensive than new nuclear (coal: $128/MWh; nuclear: $94.3/MWh).[74] Even using (as improper as it is) NOAK costs, the costs of CCS as compared to advanced coal without CCS and other base load generation sources (e.g., nuclear and natural gas) is unreasonably expensive. EPA cannot conclude that the costs of CCS for new coal-fired units are reasonable, and that CCS can be considered BSER.

d. EPA Cannot Rely On EOR to Justify the Feasibility of CCS as BSER That Has Been Adequately Demonstrated

CCS is also restricted to certain geographic areas given the need for EOR to help justify costs and the requirements imposed by EPA's proposal. CO_2 must be injected at extremely high supercritical pressures to enter either a saline reservoir or for EOR. Once injected below the surface, supercritical CO_2 is buoyant and will both rise to the top of the storage formation and radiate outward from the injection point in a horizontal manner below the caprock layer. It is essential that the

[73] 79 Fed. Reg. 1477
[74] *Id*.

geology ensures a secure fate and that CO_2 does not vertically migrate through fractures to penetrate groundwater reservoirs or leak to the surface through abandoned wells. Ideally, new plants would be located near existing CO_2 transport pipelines and geologically acceptable sequestration sites. Saline formations offer the greatest sequestration potential but are poorly understood compared to EOR operations. Further, saline formations are not evenly distributed throughout this nation, and over 90% of total capacity is found in three distinct regions—the Southeast, Southwest, and the Montana/Idaho/South Dakota region. Many regions with large population centers that consume vast quantities of electricity have none. This rule would subject consumers in these large population centers, such as the Northeast, to reduced future energy generation diversity because new coal-fired EGUs could not be built there. This would further reduce competition between power generation sources. Today's power cost increases in these regions would be further exacerbated with reduced power supply competition.

Injection of CO_2 for EOR at depleted oil and gas reservoirs has been conducted for decades in Texas and elsewhere. Such formations once held crude oil or gas and consist of a layer of non-porous capping rock over a porous rock formation, usually in the shape of a dome, which renders these sites excellent for trapping CO_2. Over two-thirds of this capacity is concentrated in the Southeast and Southwest; parts of the Midwest and the Atlantic coast have no such reservoirs. Between the limited availability of both saline and depleted oil and gas reservoirs, some states have essentially no CO_2 storage options available to them. Existing CO_2 pipelines are rare near most population centers, and states with little or no storage capacity would have to construct costly, lengthy and expensive pipeline

systems. While some pipeline capacity does exist, it is negligible in comparison to the majority of total pipeline availability in the U.S. – out of 2 million pipeline miles, roughly 4,000 exist at present for CO_2 transfer, and that is mostly for facilities that are near areas where EOR is a viable option.[75] Nor have most states granted the power of eminent domain for CO_2 pipelines.[76]

Further, there is simply no relevant operating experience to support a finding that permanent geological sequestration of CO_2 on the scale required for use with commercial power generation has been adequately demonstrated, or that any level of CO_2 emission from sequestration repositories is achievable under the range of relevant conditions for the industry as a whole. No facility has ever attempted to sequester CO_2 in the amounts that sites would have to receive, on a continuous basis, from commercial power plants. Even at sites where CO_2 has been injected for EOR or geological sequestration in the past on a smaller scale, there is no evidence as to how much of the injected CO_2 remains underground and how much, in the short and long term, escapes back into the atmosphere.

Conversely, EOR operators are concerned that the proposed rule's requirement for EOR operators that purchase CO_2 from EGUs to have to report emissions under the more stringent requirements of Subpart RR of 40 C.F.R. part 98, rather than Subpart UU with which they currently comply, will create regulatory uncertainty and risk that will result in EOR operators avoiding the purchase of CO_2 that is subject to those rules. Instead of benefiting financially from capturing CO_2 emissions, EGUs would likely have to pay EOR operators to **take** the CO_2, which

[75] "CO_2 Pipelines and EOR in the US – Regulatory Issues and Opportunities." Lawrence Wolfe, 2009
[76] "Implications of Greater Reliance on Natural Gas for Electricity Generation," Prepared For The American Public Power Association, July 2010

removes any cost justification that EPA ascribes to CCS based on EOR.[77] Moreover, in this rulemaking, EPA admits that resale for EOR is "non-economical" or unavailable for some locations in which new Subpart Da units may be built.[78] Therefore, the cost of CCS with resale for EOR does not represent the cost of installing CCS on new units throughout the country, and should not be considered in determining the proposed NSPS.

Thus, EPA has proposed a national standard that can only be met in very limited regions of the country. EPA cannot assert then that the standard is adequately demonstrated technically – significant additional work needs to be done to determine whether geologic formations across the country with promising characteristics are actually suitable for CO_2 storage. DOE recently increased its estimates of geologic storage capacity in the United States, based on the most recently released NACSA.[79] As the NACSA specifically acknowledges and emphasizes, it reflects only very preliminary reviews of geologic formations:

> The location and areal extent of promising geologic storage formations and the CO_2 resource estimates presented in this Atlas are intended to be used as an initial assessment of potential geological storage opportunities. This information provides CCS project developers with a starting point for further investigation. . . *[I]t is not intended to serve as a substitute for site specific assessment and testing.*[80]

[77] EPA also admits that resale for EOR is "non-economical" or unavailable for some locations in which new Subpart Da units may be built. 79 Fed. Reg. at 1478
[78] 79 Fed. Reg. at 1478
[79] *Available at* http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf
[80] *Id.* at 2 (emphasis in original)

These additional assessments could take significant time. Furthermore, the distribution of potential CO_2 sequestration sites throughout the U.S. is uneven. The NACSA shows that as many as 12 states have assessed storage capacity that would hold **less than one year's worth of CO_2 emissions** from major sources within the state. This figure is based on DOE's high estimate of storage capacity within the state.

CCS is by no means an emissions reduction option that could be universally available, at least not without lengthy transport for sources in major portions of the country. Further, without the NACSA recommended site specific assessments, it is not clear that the formations that have been identified have the right properties for geological storage. A formation may have one or more fractures in the caprock or may have well penetrations (which can be remediated at extra cost), or specific sites may have sufficient porosity but low permeability. Currently available information in most cases would not be sufficient to show whether CO_2 is likely to settle in a broad or narrow depth range, a question that is important to resolve to allow a determination of how the CO_2 plume will spread and to address displacement of underground fluids, which in turn factors into the property rights that must be arranged for sequestration. These are critical issues requiring costly, potentially time-consuming research and resolution. EPA's proposal fails to take them properly into account when relying on EOR to justify its determination of CCS to be BSER for new coal-fired units.

e. EPA's Proposed Rule Does Not Incentivize Technology and EPA's Rationale is Flawed

EPA engages in viciously circular logic to conclude that only by conditioning the construction of new coal base load power plants on a regulatory requirement that effectively requires CCS "will promote further development of the technology."[81, 82] EPA never explains, however, why advanced and highly efficient coal generation technologies would not accomplish the same goal and cannot assert ignorance of how to maximally incentivize new technologies. Comments on the now withdrawn April 2012 proposal gave EPA ample input on ways to achieve that goal. In the new proposal, EPA never adequately addresses those comments and instead uses conclusory statements to justify its position, and avoid the real question of what will be required to advance CCS to achieve CO_2 emission reductions in the power sector.

NMA is not alone in this assessment. Alstom, the leading developer of CCS technology, adamantly disagreed with EPA's view that the proposed NSPS based upon deployment of CCS will promote development of the technology. Rather, Alstom indicated that the more efficient and sound method of advancing CCS would be a regulatory approach that recognizes the steps of the technology process and need for financing.[83] EPA's rule and its explanation consider neither. As Alstom intelligibly articulates, "[c]ommercial power plants cannot secure financing that includes *technology still under development* and that carries with it undefined guarantees."[84] Because CCS has not even reached "demonstration scale" the technology will neither reach successful adoption and application by generators nor

[81] 79 Fed. Reg. 1468
[82] *Id.* at 1469
[83] *The American Energy Initiative*, Hearing before the House Subcommittee on Energy and Power, Sept 20, 2013 (statement of Robert Hilton, VP, Power Technologies, Alstom)
[84] *Id.*

acceptance by the financial community.[85] Alstom has previously informed EPA that it is highly unlikely that anyone would engage in the averaging scheme due to the level of uncertainty associated with unknown costs and availability of financing. At bottom, Alstom – who has a vested interest in accelerating development and deployment of the technology – concludes that the proposed standard will delay the development of CCS technology.[86]

Instead of following Alstom's recommendation, EPA chooses to rely upon a three-year old statement from AEP announcing the abandonment of its Mountaineer pilot demonstration project as support for the agency's view that a regulatory requirement will force development of the technology.[87] EPA alleges that AEP's experience shows that a regulatory requirement is necessary pre-condition to gain approval for cost recovery by public utility regulators. In an ironic contradiction of its feigned concern expressed about increased electricity costs, EPA is here assuming that their rule will allow state public utility commissions to freely burden electricity consumers with increased power rates caused by mandated implementation of this technology. Yet, EPA provides no evidence that a regulation setting a standard premised on the use of CCS would result in approval of cost recovery. Moreover, the pilot project at AEP was a retrofit of an existing plant, which is not the subject of this rule and standard. Notably, Alstom, a partner in that same AEP project, sees the "undemonstrated" status of the technology as the hurdle for its further deployment.

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[85] *Alstom comments in response to April 13, 2012 Proposed GHG Standards for New Stationary Sources,* p. 4
[86] *Id.*
[87] 79 Fed. Reg. 1436

Utilities also have come forward to challenge EPA's assessment that a regulatory requirement will advance development of the technology at this stage. According to Dominion, the obstacles to deploying CCS are additional federal funding to adequately demonstrate the technology at utility scale along with permitting and liability protections for transportation and storage of CO_2.[88] Like Alstom, Dominion's chief executive faulted EPA's original averaging scheme as a viable option. Because of the undemonstrated status of the technology, according to Dominion, the then proposed 2012 standard would:

- Not succeed as a technology forcing requirement;
- Create an insurmountable hurdle to obtaining financing and securing public utility commission approval;
- Jeopardize financing since without assurance that a new facility without adequately demonstrated technology would be able to operate for its expected life of 30-plus years, a CCS requirement during some phase of an averaging scheme.[89]

The views from Dominion, other power providers, and carbon capture technology experts bear out that EPA's assessment is incorrect. For example, Michael Holmes and Edward Steadman, Deputy Associate Directors of research at University of North Dakota Energy and Environmental Research Center, see an existing need to *scale-up and further prove* carbon capture before utilities will be able to use these technologies and the technology vendors to provide guarantees.[90]

[88] *Hearing before the House Subcommittee on Energy and Power*, July 16, 2012 (statement of Thomas Farrell II, President & CEO, Dominion)
[89] *Id.*
[90] *Argus Air Daily*, Nov. 4, 2013 (Interview with Holmes and Steadman)

Even the relevant DOE experts agree that further testing and proving of carbon capture is necessary as the current technology for capturing CO_2 is inadequate to meet the goal of reducing the cost of CCS-generated electricity to a point where it would be deployed. Consequently, DOE has been seeking to develop "next-generation" equipment and processes that capture CO_2 more quickly and more completely but use less energy than the technology tested to date. Those projects, however, will not begin reaching pilot and demonstration stages until the next ten to 15 years.[91] Holmes and Steadman agree with DOE – testing these technologies and reducing their costs through second and third generation technologies is not a matter of years, but a matter of decades.[92] EPA's arbitrarily chosen standard cannot alter these timelines due to the simple fact that years are required for adequate demonstration of these technologies. The testing and development required for better materials for absorbing CO_2 and reducing the amount of energy used in the capture process must begin with small-scale test plants (0.5-5 MW) which are too small to be covered by the proposed rule. That testing and demonstration will span at least the eight year period EPA is provided under the CAA to revisit the NSPS and propose a change if the technology has proven successful.

EPA's view that a regulatory requirement for CCS will incentivize development of the technology conveniently omits what would really be required in terms of a regulatory push. Under the current proposal, not only is there no incentive to develop CCS, EPA creates a disincentive as it further induces

[91] Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide* p.6 (June 2012)
[92] *Argus Air Daily*, supra. at 6

construction of NGCC units (and even lesser efficient single cycle turbines in order to back up renewable generation) that are not burdened with the cost of required CCS technology installation. Even EPA admits this in its supporting rationale for the rule, asserting that most of the new base load generation capacity built in this country will be NGCC units in any event. Yet EPA proposes a standard for the fastest growing source of CO_2 in the power sector and does not require CCS. So why would the utility industry invest in developing CCS if it can simply build NGCC and single cycle gas units without CCS? Simply put, they will not.[93] Instead of offering an incentive-laden path forward for new coal units and for CCS technology, EPA instead offers utilities a false choice between new coal with CCS and uncontrolled NGCC units given the economics and technological uncertainties of installing CCS at commercial scale.

EPA's reasoning also breaks down upon examination of the NGCC standard. Not only is there no discussion of inducing better performance from NGCC—now guaranteed by the rule to be the predominant form of new base load generation capacity – the standard is substantially higher than what the agency knows and the evidence shows can be achieved with the best existing technology widely deployed today.

To be clear, NMA is not suggesting that EPA should mandate CCS for NGCC units, but simply pointing out the inherent contradiction between the agency's

[93] Statements of Howard Herzog, senior research engineer, MIT re: Incentivizing development of carbon capture and storage technology would require setting emission limits that would require CCS on natural gas plants. *See* Kevin Bullis, *EPA Carbon Regs Won't Help Advance Technology*, MIT Technology Review Sept. 19, 2013. (http://m.technologyreview.com/view/519486/epa-carbon-regs-wont-help-advance-technology/); and Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide,* p. 13 (June 2012) (EPA action will shift electricity production to natural gas without CCS rather than CCS capable plants)

reasoning for setting a standard for new coal plants based upon CCS and the standard for NGCC units. EPA's decision to require CCS rather than setting a standard based upon the best performing SCPC and IGCC technology is unreasoned and contradictory. CCS is not adequately demonstrated for NGCC or coal based load power plants. The status of the technology for either application is roughly the same – still immature and unproven in commercial scale power generation.[94]

EPA cannot justify this disparate treatment with claims that CCS is too expensive to install at NGCC units since NGCC installation costs are significantly lower than those for coal units. For NGCC units, CCS would have a lower cost ($86.58/MWh) than for a SCPC coal unit equipped with CCS ($137.28/MWh) *excluding transport and storage*.[95] In both cases, the cost of electricity is substantially higher than the cost using the best technologies today without CCS (45 percent higher for natural gas plant; 70 percent higher for coal-based plant).

EPA's rationale for this decision is fundamentally flawed. An instructive analogy and hypothetical comes in the form of light bulb efficiency standards promulgated by DOE. In order to incentivize technological development and deployment, DOE promulgated light bulb efficiency standards requiring that , all manufacturers stop production of conventional light bulbs (the classic bulb) and meet efficiency standards that effectively mandated use of lower power bulbs (the "pig tail" bulbs), without exemptions. All manufacturers switched over to producing more efficient bulbs, and costs rose for production across the board as an initial

[94] For a robust discussion of the status of CCS technology please reference numerous other sections of these comments, both below and above
[95] DOE, NETL, *Updated Costs (June 2011 Basis for Selected Bituminous Baseline Cases* (Aug. 2012). (http://www.netl.doe.gov/energy-analyses/pubs/BaselineCostUpdate.pdf), emphasis added

matter before coming down over time as production picked up. However, EPA is not following this technological forcing path – instead, applying EPA's logic to DOE's efforts would lead to perverse results. In effect, EPA would be requiring certain manufacturers of light bulbs to become more efficient while wholly exempting others – driving up costs for one set of manufacturers while allowing others to do nothing and continue producing old, status quo level product. This would have given them a significant advantage and not produced any energy savings at all, as consumers would then make the rational choice to continue buying the lower cost bulbs that function well. As such, EPA's logic behind forcing coal-fired units to install CCS while determining that the present status quo for natural gas-fired units is merely "good enough" as is fails. This is an unreasoned and arbitrary decision by the agency, and it does not satisfy the legal requirements of CAA section 111. EPA should withdraw this proposed rule and set a standard based on reasonably available technology.

f. EPA's Proposed Rule Will Freeze CCS Development and Deployment

In EPA's discussion of setting CCS as BSER for coal units, EPA argues that setting CCS as BSER for coal units would "promote deployment and further development of the technology." However, EPA's regulatory structure in the proposed rule is in fact setting up a false choice for utility operators. By offering the choice between CCS-controlled coal units on the one hand and uncontrolled NGCC units on the other, EPA is instead providing a distinct disincentive and likely roadblock to the further development and deployment of CCS technologies. Given the cost disparities, as admitted by EPA in its LCOE analysis and discussed

extensively previously in these comments, between CCS-equipped coal units and NGCC units without CCS, the proposed NSPS simply and irretrievably incentivizes a further build out of NGCC units and the freezing of any new investments in the development of CCS. Thus, by effectively forcing utilities to choose natural gas without CCS over coal with mandated CCS, EPA just as effectively frustrates the further development and implementation of CCS technology, because no one is required to install CCS on gas units. As such, CCS is unlikely to be further developed under EPA's proposal.

Further, utility operators have obligations to their shareholders, customers and public utility commissions to provide low cost and affordable power, regardless of fuel type. While utilities also value fuel diversity in order to hedge their risks against the rise in cost of fuel supplies be they coal, natural gas or otherwise, that diversity must be justified economically. To put it bluntly, utilities do not value fuel diversity simply for the sake of being diverse – they are obligated to consider market fundamentals and justify their decisions based on sound logic and economics. By requiring all new coal units to install and operate CCS systems, with their admitted high capital costs for installation, operation and maintenance, EPA has effectively priced new coal out of the ability of utilities to justify building said units for the sake of fuel diversity concerns. CCS is still in 'first of a kind' developmental stage – and its requirement for only coal units with the itinerant costs makes CCS technology economically infeasible. Thus, utilities are effectively barred from developing CCS projects by the combination of EPA's regulatory requirements, their need to respond to the fundamental economics and concerns of

providing affordable power, and the continued availability of the option to build NGCC units without any carbon constraints.

Instead of incentivizing CCS development for a 'carbon constrained world,' as EPA states, the current proposal will hinder the development of CCS at an absolutely critical time, and cedes the development of commercial scale carbon capture technology to other nations. This proposal is a "pull-me" rule that does not "pull" whatsoever. Under the proposal, because utilities cannot commit to building new coal generation given the risks of installing unproven and commercially infeasible CCS technology, new coal generation will not be built. As a result, coal generation is not incentivized to achieve higher efficiency potential (such as ultra-supercritical coal), the deployment of CCS vanishes, and natural gas becomes locked in as the de facto fuel du jour to replace coal since the rule does not require natural gas to do anything to reduce CO_2 emissions. This rule therefore acts as a disincentive for the continued innovation and deployment of the CCS plants which early adopters require, harming not just coal, but our entire economy and America's ability to be a leader in CCS development in the future.

Any meaningful effort to achieve long-term, sustainable reductions in global GHG emissions will depend on the development and deployment of new energy technologies, including advanced clean coal technologies and CCS. The rapid development, demonstration and widespread deployment of such technologies are of paramount importance in any reasoned and effective effort to address climate change concerns. The proposed rule hinders rather than helps attain this goal.

III. The Utility Sector's Experience in Developing and Deploying Emissions Control Systems is Highly Relevant in an Assessment of When a System is Adequately Demonstrated

The utility sector has significant experience in installing emissions control systems and advancing technology to help address pollution concerns relating to the combustion of coal for electricity including the historic examples of the development of control systems to help reduce NO_x and SO_2 emissions by the development and installation of SCR, FGD and other pollution control technology. Experientially, the FGD and SCR examples are highly relevant to EPA's proposed determination that CCS is adequately demonstrated. The power sector developed, tested, integrated and operated control systems for FGD and SCR systems over decades, taking an evolutionary approach to the technology that ultimately led to deployment at commercial scale after which they were determined by EPA to be adequately demonstrated and incorporated into the CAA regulatory scheme for setting emission standards. This pathway is markedly different from the current experience and status with CCS technology – CCS is still in its infancy as a technology, and is not nearly as advanced as FGD and SCR systems were when EPA began incorporating them into their regulatory processes.[96]

EPA acknowledges the evolutionary path of control technology in the proposed rule's preamble. Specifically, EPA describes the difference between a first-of-a-kind (FOAK) and the Nth-of-a-kind product (NOAK). Notably, EPA considers only improvements in the path from a FOAK to a NOAK – and ignores the possibility that additional experience will uncover new risks that elevate cost or

[96] This evolutionary path for emission control technology innovation, development and deployment is described more fully in the report *Status of Carbon Capture and Storage (CCS) Demonstrations in Response to Proposed New Source Performance Standards for CO_2* prepared by Ed Cichanowicz for UARG and attached as Appendix 2

compromise performance.[97] In reality, the evolution of a control technology from FOAK to NOAK is unchartered – this path is laden with "downside" risks as well as opportunities for cost savings.

The "downside" risks for evolving control technologies are exemplified by the evolution of controls for PM, SO_2, and NO_x. Refinements to PM controls tried in the mid-1970s included pre-chargers to enhance the performance of ESPs and fabric filters to capture PM generated by high sulfur coal. These refinements were not successful in their first decade of development. Early generation pre-chargers provided less performance improvement to ESPs than initially estimated and collecting particulate matter from high sulfur coal with a fabric filter increased gas pressure drop. Regarding SO_2 control, early FGD processes utilized packed bed absorbers in an attempt to minimize costs; these often plugged and compromised the reliability of the system. Early NO_x controls involved aqueous scrubbing of NO_2 and regenerable, moving and fixed bed processes for combined NO_x and SO_2 control. These concepts – appealing and the subject of considerable pilot plant and demonstration tests – were all commercially offered; that is at least one supplier offered the product. However, guarantees of performance – and a lack of experience assuring reliability – did not match owners' needs. Ultimately these processes were withdrawn from the market.

Most early FGD work was conducted in both the U.S. and Japan. Pilot plant work began in the late 1960s and escalated rapidly through the mid-1970s, as numerous FGD variants were tested. The earliest pilot plants averaged 10-20 MW with sizes increasing and averaging over 100 MW as early as 1973. The first NSPS

[97] 79 Fed. Reg. 1471

for SO_2, issued in the U.S. in 1971, codified a limit of 1.2 lbs. /MBtu that could be met using "compliance" coal, physical coal cleaning, or FGD. Thus, the 1970 NSPS did not mandate FGD – there were alternative means to comply.

In 1977 Congress amended the CAA and in 1978 EPA revised the NSPS for SO_2 to a level that eliminated any option but FGD. By that time significant experience for FGD had accumulated on pilot plants and commercial units – by 1978 commercial experience totaled more than 10,000 MW. This experience provided the basis for meaningful process guarantees.

The power sector's experience with SCR systems is likewise instructive. The events that prompted SCR application followed FGD by about a decade. In the late 1970s, SCR had been installed at numerous pilot plants in Japan as well as in several commercial demonstration tests. Both the EPA and EPRI operated pilot plants on domestic U.S. fuels. Continued advances in combustion NO_x control technology in the U.S. in the early 1980s provided a low cost means to control NO_x from existing units.

SCR was most extensively deployed in Europe. By the mid-1990s, international experience totaled approximately 40,000 MW in Europe and perhaps up to 25,000 MW in Japan. At the same time, approximately 4,000 MW of coal-fired capacity had been deployed with SCR domestically. In addition, EPA issued NSPS for NO_x that required SCR on most coals – excepting lignite, for which experience was very limited for a variety of reasons. By the year 2000, in the U.S. about 12,000 MW of capacity were equipped with SCR.

The experience with both systems illustrates the evolutionary nature of each control technology – neither became widely used until they had been demonstrated

at scale at a number of different operational facilities. Only once FGD and SCR systems were operationally demonstrated at numerous facilities were both emissions controls manufacturers and power operators confident of the ability of each system to deliver (1) the proposed environmental benefits, and (2) that those systems could deliver commercial power and reduce emissions concurrently. Unlike FGD and SCR, EPA here is mandating CCS, which lacks authentic experience at large commercial power plants. As noted extensively above, the only CCS applications are located at either small commercial units producing CO_2 for industrial use, or pilot plant or demonstration-scale equipment. The prospect of commercially proving CCS – that is, offering CCS for sale with performance supported by meaningful manufacturer guarantees – cannot be assessed until current and pending pilots and demonstrations proceed and experience is gained to scale, generalize, and integrate CO_2 capture processes with variable power generation and also address the transport and storage of the material.

Evaluating the feasibility of CCS for applicability to the array of fuels and sites that typify dedicated power generation facilities in the U.S. will require broad experience. At a minimum, there is the need to obtain operating data over several years from at least eight utility-scale projects – similar to the process in which FGD and SCR systems were developed over numerous years and demonstration projects. CCS technology has been under development for less than half the typical 25-year development period for power plant technologies. As such, determining that CCS is the BSER that has been adequately demonstrated at this juncture is both premature and unprecedented.

IV. EPA's Determination that CCS is BSER Radically and Inexplicably Departs from the Agency's Longstanding Interpretation and Application of "Adequately Demonstrated" Under Section 111(b)

For over forty years, EPA has interpreted and applied CAA section 111(b) in a manner that looks to emission control systems currently in use within an industry as the best system for deriving an achievable standard by all sources in the source category. This longstanding history is reflected in EPA's decisions that either determine or reject a system or technology as BSER. The most prominent examples include:

- Dry flue gas desulfurization systems for EGUs (1979): EPA determined that wet scrubbers were adequately demonstrated, but rejected a similar determination for dry scrubbers. At the time, wet scrubbers had been in commercial use since the late 1960's and wet scrubbing had increased substantially by the time EPA adopted the NSPS for sulfur dioxide emissions from new coal-fired power plants in 1979. On the other hand, there were no dry scrubbers in operation at utility plants, and the only information available related to *pilot scale* units.[98] Indeed, the absence of experience with dry scrubbing technology at "large-scale" facilities was one basis for EPA concluding that what it characterized as a promising emerging technology was not adequately demonstrated.[99]
- Electro-Static Precipitators on EGUs (1979): ESPs were considered BSER because "since ESP's were introduced to the utility industry in

[98] 44 Fed. Reg. 33594 (1979)
[99] See *Sierra Club v. Costle*, 657 F.2d 298, 341 n.157 (D.C. Cir. 1981) (it would be premature to conclude that dry scrubbing is adequately demonstrated)

the 1920's, they have become the most widely used means of controlling particulate emissions from coal-fired boilers."[100]

- Selective Catalytic Reduction Systems (1984): In NSPS standards for industrial boilers, EPA rejected SCR as adequately demonstrated. The reasoning was that SCR had not been applied in the U.S. to full-scale steam generating units firing coals. According to EPA, "[t]echnical and economic questions exist concerning the application of SCR to steam generating units which *precludes* the conclusion at this time SCR is a universally demonstrated technology for the purpose of developing standards of performance limiting NOx emissions from steam generating units."[101]
- Selective Catalytic Reduction Systems for EGUs (1998): After rejecting SCR as BSER for boilers 14 years earlier, EPA determined that they were now adequately demonstrated as BSER after reviewing the operation and installation of 10 domestic and 212 international SCRs.[102]
- Selective Catalytic Reductions Systems for Portland Cement Plants (2008): EPA rejected SCR for cement kilns because they were not used in the type of preheater/precalciner kilns used in the U.S. Additionally, EPA found that uncertainties exist as to the specific performance level and characteristics that affect operating costs. In sum, the limited experience of with SCR on cement kilns

[100] 44 Fed. Reg. 33580 (1979)
[101] 49 Fed. Reg. 25102, 25109 (1984)
[102] 63 Fed. Reg. 49442 (Sept. 16, 1998)

(notwithstanding use in Europe) precluded a determination that SCR was BSER.[103]

- Integrated Gasification Combined Cycle for New Coal-Fired EGUs (2006 & 2012): EPA rejected IGCC as BSER even though "new steam generating projects that use IGCC technology will [remove] over 99 percent of the sulfur associated with coal by the coal-gasification process."[104]

Previously, EPA consistently has looked to emissions technology that has actually been in use and demonstrated to work in a given industry as the basis for a determination that it is, in fact, "adequately demonstrated." As the above examples demonstrate, EPA's BSER determination in this proposal radically departs from the longstanding interpretation and application of section 111. Here the agency has skipped over technology that has been demonstrated to work for coal EGUs (e.g., higher efficiency conventional coal units such as USCPC, SCPC or IGCC combustion systems), and leapt to a technology that has distinct and complex components that have not been demonstrated in an integrated commercial scale EGU. Absent in this regulatory history is **any** NSPS set on a purely speculative basis, as EPA has done here with regards to CCS technology: two plants that remain under construction; two still on the drawing board; several pilot scale projects related to separate components of CCS; and literature.[105]

[103] 73 Fed. Reg. 34072, 34079-80 (June 16, 2008)
[104] 70 Fed. Reg. at 9715 (2005). EPA's reason for rejecting IGCC was based upon the conclusion that it "is not appropriate in every situation." EPA Response to Comments at p. 28. EPA reached the same conclusion six years later, see 76 Fed. Reg. at 25061
[105] 79 Fed. Reg. 1471

EPA first adopted NSPS for coal-fueled utility boilers in 1971 as a part of its first set of NSPS.[106] These standards covered SO_2, NO_X and PM emissions. EPA has revised these standards from time to time over the years, most recently in 2011.[107] Thus, in addition to there being a great deal of precedent for EPA's adoption of NSPS requirements generally; there is a great deal of precedent for EPA adoption of performance standards for coal-fueled utility boilers specifically. On behalf of NMA, RMB Consulting & Research, Inc. reviewed EPA NSPS rulemakings for 68 source categories. RMB did not review approximately 10 NSPS rulemakings, which focused on volatile organic carbon (VOC) emissions and did not appear particularly relevant to the study. RMB concluded that EPA has **never** before adopted a performance standard where the standard had not been achieved by multiple commercial-scale facilities in the source category to which the standard applies. EPA's approach to its proposed CO_2 NSPS for coal-fueled utility boilers and IGCC units thus is entirely unprecedented.

Further, the large majority of the categories for which EPA has set NSPS involve facilities that have stacks through which the facilities' emissions pass or where it was otherwise feasible to do emissions tests. In most of these cases, EPA based its NSPS on monitored data obtained from doing stack tests at multiple units operating at commercial scale. For certain pollutants in these source categories, EPA used chemical analyses of the input fuel to determine emission standards based on operating experience at multiple existing commercial-scale units. In some cases, EPA set opacity standards based on actual observations of visible emissions.

[106] 36 Fed. Reg. 15,704 (Aug. 17, 1971).
[107] 76 Fed. Reg. 24,976 (May 3, 2011).

Thus, in all of these cases, EPA based its determination of "demonstrated" technology on actual data from units in operation within the source category. By contrast, in its proposed NSPS for CO_2 emissions from coal-fueled utility boilers and IGCC units, EPA has not based the proposed standard on actual monitored data from units at full commercial operation because there is no such data. Even more damning of EPA's chosen approach is that in some cases, the lack of actual data from facilities in commercial operation has caused EPA not to adopt numerical standards.[108]

In short, EPA can point to no evidence to support its claim that CCS has been demonstrated at all on a commercial scale EGU, let alone that it has been adequately demonstrated as BSER.[109] In this regard EPA does not, and cannot, provide a reasoned rational explanation for making the determination that CCS is adequately demonstrated as BSER.

V. EPA's Reading of Applicable Case Law is Unavailing and Without Proper Context in an Effort to Bootstrap its BSER Determination

EPA maintains that its BSER determination for new coal-fired utility boilers and IGCC units "is rooted in the provisions of CAA section 111 as interpreted by the United States Court of Appeals for the D.C. Circuit."[110] Further, EPA says these court "interpretations are of *central importance* to the EPA's justification for the standards of performance in the present rulemaking."[111] Of course, EPA does not – nor could it – maintain that these interpretations compel EPA to adopt the partial

[108] *See, e.g.,* EPA NSPS for VOC emissions from Crude Oil and Natural Gas Production, Transmission, and Distribution, 76 Fed. Reg. 52,738 (Aug. 23, 2011);
[109] See attached report, "REVIEW AND SUMMARY OF TECHNICAL BASIS USED BY EPA IN SETTING STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES," attached as Appendix 1
[110] 79 Fed. Reg. 1462
[111] *Id*. (emphasis added)

CCS-based standard. Nor does EPA suggest that the case law precludes the agency from setting a standard of performance that is based upon the high performing versions of SCPC and a separate standard for IGCC projects. The regulatory history and subsequent court decisions upholding EPA's past NSPS standards clearly demonstrate that such a course would be technically and legally justified.

Thus, it is difficult to discern why the case law is of "central importance" to EPA's justification for the standards. After all, the justification should arise from the statutory factors laid out in CAA section 111(b) related to the status of the technology, costs, achievability of the standard and other factors, including counterproductive impacts from the standard on the economy, industries and energy supply. EPA's near-obsessive focus on the case law — which **far exceeds** the attention devoted to the technology evaluation — is a misguided attempt to gird the legal basis for the unprecedented, unusual and unavailing reasoning for its BSER determination.

EPA's discussion of the case law correctly begins with the core question of **how** a standard of performance is derived from a BSER that is adequately demonstrated. After that, the discussion becomes unhinged from this central question by (1) failing to provide context of the underlying agency determinations being reviewed by the court; and (2) improperly conflating, or confusing, cases that address the separate requirements of "achievable" and "adequately demonstrated."

For the most part, EPA focuses on court decisions that address the statutory requirement that standards must be "achievable," and gives little credence to cases that address the central question related to the "adequately demonstrated" requirement of the statute. The most instructive case addressing the issue of

adequately demonstrated is *Sierra Club v Costle*, which involved a challenge to EPA's identification of wet scrubbers as "adequately demonstrated" and dry scrubbers as not.[112] The facts are of central importance in this instance: (1) wet scrubbers had been in commercial use in the United States since the late 1960's and the use of wet scrubbers had increased substantially to show performance in the source category; and (2) dry scrubbers had not been in operation at utility plants and at that time three full scale dry scrubbing systems were being installed on utility boilers scheduled to start operations two years later and bids were outstanding for five more systems for utility boilers. On these facts, the D.C. Circuit determined that:

> We do not hold that dry scrubbing is adequately demonstrated technology. Indeed, the record in this case would indicate the contrary... '*[N]o full scale dry scrubbers are presently in operation at utility plants so information available* … dealt with prototype units. … We see *no basis on this record which would justify extrapolating from the pilot scale data to the conclusion that dry scrubbing is adequately demonstrated for full scale plants throughout the industry*. … For these reasons, it would be *premature* to conclude that dry scrubbing is adequately demonstrated technology.[113]

The *Sierra Club* decision clearly points to the flaw in EPA's BSER determination for new coal-fired power plants. The case for rejecting CCS as adequately demonstrated for the purposes of the proposed rule is even stronger than the dry

[112] 657 F. 2d 298 (D.C. Cir. 1981)
[113] *Id*. at 341, n.157 (emphasis added)

scrubber example given the following facts: (1) no full scale integrated CCS systems are in operation at utility plants; (2) apart from the two projects under construction (that have continued to face cost overruns and delays), the other projects listed by EPA have not made any significant progress toward commencing construction, let alone operation; and (3) the only data EPA is left to consider is from proto-type pilot projects that cannot be extrapolated to full scale power plants—IGCC or SCPC.

Nor can EPA rely on *Lignite Energy Council v EPA*, another key case discussed by the agency, in order to justify its BSER determination for new coal plants. [114] The underlying issue in that case was EPA's determination that SCR was "adequately demonstrated" as BSER for NO_x control for both utility and industrial boilers. For utility boilers, SCR's had already been operating at full scale EGUs with approximately 4,000 MW of capacity equipped with it by the mid 1990's. In that time period, approximately 40,000 MW of capacity in Europe and almost 25,000 MW in Japan had already installed SCRs providing additional experience from applications to EGUs using different coal types and boilers. The question in Lignite Energy was not whether SCRs were adequately demonstrated; rather whether this "flue gas treatment" technology constituted the best system when compared to other combustion controls. It was argued that SCR was not the best demonstrated system because the incremental *cost* of reducing NOx emissions was higher with SCR than combustion controls. According to the court, the cost increase was only

[114] 198 F. 3d 930 (D.C. Cir. 1999)

modest in newly constructed boilers—a contention that was left unchallenged by the petitioners.[115]

The court did uphold EPA's determination that SCR was BSER for industrial boilers and found the agency reasonably explained why it could use the longstanding use of that technology on utility boilers to determine that it could be successfully used on industrial coal boilers given the *minimal differences* between the two types of boilers. As the court stated, EPA showed that SCR as successfully applied to coal-fired utility boilers *under a wide range of operating conditions* that were *analogous* to the load cycles of industrial boilers.[116]

The court also makes a key distinction in *Lignite Energy*, stating that where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture. While the court noted that EPA may compensate for a shortage of data through the use of other qualitative methods, it also cautioned that EPA may only do so through the *reasonable extrapolation of a technology's performance in other industries*.[117] In this instance, choosing to set BSER based upon the application of CCS in its component parts in other industries is a patently unreasonable extrapolation by the agency. Not only has no other industry fully integrated all of the necessary components of CCS in to one complete operational system, but electric utilities are unique since any EGU that would install and operate CCS to comply with EPA's proposed NSPS would need to have *all* of the component pieces work continuously and flawlessly with one another in order to provide continuous

[115] 198 F. 2d at 933
[116] *Id*. at 934 (emphasis added)
[117] *Id*. (emphasis added)

base load power. Given the total lack of demonstration that all of these components can work seamlessly and continuously together without interruption, EPA's BSER determination in the proposed rule grossly exceeds the scope of discretion recognized by the court in *Lignite Energy*.

Lignite Energy confirms that BSER rests upon a control system that has been demonstrated through commercial application as was the case for utility boilers. And extending that system's successful application in one industry to another cannot be speculative, rather it must be reasonable and supported by showing that it can perform under similar operating conditions for the regulated industry in question.

The remaining cases discussed by EPA do not address the central question of whether a control system had been adequately demonstrated.

- *Essex Chemical Corp. v. Ruckelshaus*: The selection of dual absorption as BSER in elemental sulfur burning plants was not challenged. Rather it was the achievability of the limitation standard set by using that technology.[118]
- *Portland Cement Association v. Ruckelshaus*: The court did not address whether a specific control system had been adequately demonstrated. Instead, the court dealt only with the question of whether the standards were "achievable" with sufficient data and analysis.[119]
- *National Asphalt Pavement v. Train*: The technology selected as BSER was conceded as adequately demonstrated and installed at a reasonable cost.

[118] 486 F. 2d 427, 436 (D.C. Cir. 1973) ("Petitioners do not object to EPA's selection of dual absorption as the best system of emission reduction which has been adequately demonstrated.")
[119] 486 F.2d 375, 391(D.C. Cir. 1973)("It is the achievability of the proposed standard that is in issue.")

However, petitioners contested the technology selected could meet the emission limitation.[120]

- *Portland Cement Assn. v. EPA*: Again, the control technology selected by EPA as BSER to control PM and SO_2 was not questioned. In this case, the technology could be applied to *any* kiln type.[121]

Both the regulatory history of EPA's implementation of section 111 and the case law instruct that an "adequately demonstrated" control system or technology, at a bare minimum, is one that has actually been **installed and operated at commercial scale** for a sufficient period to ascertain their performance in the source category. Emerging or promising technologies have been consistently eschewed as "adequately demonstrated" with the agency revisiting their status and performance later when considering a revision to the source category NSPS. Here, no partial CCS system has been constructed and operated at a commercial scale EGU.

a. EPA's Departure From Past Precedent in Setting BSER Requires it to Withdraw the Proposed Rule

EPA's proposed rule has significantly deviated from past precedent in determining how BSER is set, as explained in the above section. In deviating from well-established precedent in determining that CCS is adequately demonstrated as the best system of emissions reduction for coal units, despite the fact that there is

[120] 539 F. 2d 775, 786 (D.C. Cir. 1976) ("The Administrator concluded, and petitioners concede, that the best system of emission reduction that has been adequately demonstrated for the asphalt concrete industry is represented by a venture-scrubber . . . or a baghouse")
[121] 665 F. 3d 177, 190 (D.C. Cir. 2011) (Petitioner "nowhere even attempts to dispute this point.")

no single commercially operating facility that has used utility scaled CCS, EPA's proposed rule cannot survive and must be withdrawn.

i. Precedent Requires EPA to Cite an Operating Commercial Facility with CCS in Determining it to be Adequately Demonstrated

The control systems EPA typically relies upon in developing performance standards are generally well established and there is little question that they have been "adequately demonstrated." Often, the control systems chosen as the "best system of emission reduction" have been widely used in the industry in question for many years, and the primary issue EPA addresses in its standard-setting analysis is whether those existing controls are capable of achieving better performance at new units than they have already shown to be capable in the past at existing units.

On occasion, EPA will seek to establish as a best system of emission reduction a control system that is only in operation at a relatively small number of units. However, other than the example addressed in *Lignite Energy*, there are no other identified examples in which EPA has established as the "best system of emission reduction … that has been adequately demonstrated" a technology that has never **actually been applied** to an existing unit in the same industry.

EPA has also issued determinations in the past that some technologies were, in fact, *not* adequately demonstrated. These decisions provide an equally helpful point of reference, such as the dry scrubber technology that EPA rejected in establishing standards for electric utilities in the 1970s that was upheld and endorsed in *Sierra Club v. Costle*. Since only three such systems were under construction, and only a few more were planned, EPA determined (and the court agreed) that dry scrubbers were not yet adequately demonstrated (even though the

technology is now in use around the country). In this instance, even the expectation that the control systems under construction would be operational within a few years was deemed insufficient for EPA to determine that the control systems had been adequately demonstrated.

Another relevant example of an EPA determination that a control system was not demonstrated involved the application of SCR technology to industrial boilers. As noted above, *Lignite Energy v. EPA* upheld EPA's decision to impose SCRs on industrial boilers in 1998, but that decision came after a 1986 decision by EPA to *reject* SCRs as a demonstrated technology for industrial boilers. In its 1986 rule, EPA rejected SCR as a demonstrated technology for industrial boilers:

> SCR has not yet been applied in the United States to full-scale steam generating units firing coals and high nitrogen oils which have the highest NO_x emissions potential. Technical and economic questions exist concerning the application of SCR to steam generating units which preclude a conclusion at this time that SCR is a universally demonstrated technology for the purpose of developing standards of performance limiting NO_x emissions from steam generating units.[122]

In short, EPA's 1986 analysis indicated that SCR had not been applied to utilities or industrial boilers, and therefore could not be considered adequately demonstrated for either type of boiler. However, according to EPA's subsequent 1997 proposal (which led to the 1998 final rule addressed in *Lignite Energy v. EPA*) seven SCRs

[122] *Standards of Performance for New Stationary Sources; Industrial-Commercial-Institutional Steam Generating Units, Proposed Rule*, 49 Fed. Reg. 25102, 25109 (June 19, 1984)

had been installed and begun operating on utility units between 1994 and 1996.[123] In light of these successful installations, SCRs were clearly demonstrated for utility boilers. Thus, EPA considered the control system adequately demonstrated for both utility and industrial boilers, given the minimal differences between the two types of boilers.[124]

Similarly, the following provides EPA's reasoning for rejecting SCRs as an adequately demonstrated technology for Portland cement plants:

> Though SCR is demonstrated in Europe, SCR has never been used on any cement kilns in the U.S. Uncertainties exist as to its specific performance level and catalyst plugging and fouling, which affects operating costs. As noted earlier, three cement kilns have used SCR, all in Europe. Despite the use of SCR on three kilns in Europe, there are several uncertainties as to whether they represent BDT. Of the three kilns in Europe using SCR, two are preheater kilns, and one kiln is a Polysius Lepol technology kiln, which is a traveling grate preheater kiln. None of the kilns using SCR are preheater/precalciner kilns which are the only type of kiln that will be built in the U.S. Also, one of the European cement plants has switched back to using its SNCR system

[123] *Proposed Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Proposed Rule*, 62 Fed. Reg. 36948, 36950 (July 9, 1997) (containing Table 1 listing seven SCRs that came online between 1994 and 1996)
[124] *Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Final Rule*, 63 Fed. Reg. 49442, 49444 (Sept. 16, 2013) ("The primary difference between utility and non-utility boiler types may be that, on average, non-utility boilers may be more likely to operate with fluctuating loads. This difference in operating pattern may appear to have an impact on the characteristics of the stack gas. However, the NSPS is based on a 30-day averaging period to accommodate normal fluctuations in performance. Further, as discussed above, new analyses of two facilities that operate under cycling conditions have shown that SCR can meet the revised standard over a 30-day averaging period.")

> to compare the operational costs of the two systems to evaluate which technology is better and more economical. Because the experience with SCR on cement kilns is so limited, issues have been raised on SCR applicability to cement kilns.[125]

Thus, EPA's own precedent suggests that experience with other types of units or on units overseas should not be sufficient to determine whether a system is adequately demonstrated. These examples of EPA determinations as to whether a control system is or is not adequately demonstrated provide important points of comparison and reveal the unprecedented nature of EPA's proposal to require partial capture CCS on all future coal-fired power plants.

ii. EPA Must Withdraw the Proposed Rule Since CCS is Not Adequately Demonstrated

As discussed, EPA has relied on five sources of information to support its decision to require all new coal plants to implement partial CCS in its proposed NSPS for greenhouse gas emissions from fossil-fuel fired electric utilities: (1) the ongoing construction of one unit in the United States and one in Canada; (2) two more planned units for which construction has not yet commenced; (3) the use of various components of a CCS system in other industries; (4) international experience with the technology; and (5) literature resources. However, conspicuously absent from that list is any information regarding actual installation and use of partial CCS because none exists – no existing unit has ever employed the control system EPA has determined to be "adequately demonstrated" for all future fossil-fuel fired electric utilities. As the legal analysis above confirms, that

[125] *Standards of Performance for Portland Cement Plants; Proposed Rule*, 73 Fed. Reg. 34072, 34079-80 (June 16, 2008)

fact alone renders EPA's proposed GHG NSPS not only unprecedented, but arbitrary and capricious as well.

Even though EPA attempts to draw support from *Lignite Energy v. EPA* by asserting that it is simply applying technologies from one industry to another, that argument fails to recognize how similar the utility and industrial boilers were in that case and how dissimilar the various industries EPA cites as support for its CCS proposal are from electric generating units. If CCS was already in use on industrial boilers, EPA might be able to claim that the control system should be considered "adequately demonstrated" for use in the utility industry. However, EPA's attempt to pull technologies from various disparate industries – capturing CO_2 from natural gas refining, transporting CO_2 from natural deposits to enhanced oil recovery sites, and injection of CO_2 at those sites – stretches *Lignite Energy* **far beyond** the reasoning employed by the D.C. Circuit in that case.

In addition, the legal analysis EPA provided in its proposal fails to address the more obvious analog from *Sierra Club v. Costle*, in which the court soundly rejected (and affirmed EPA's own decision to reject) dry scrubbers as an adequately demonstrated technology for electric utility units. Although that technology is now in use around the country, at the time of EPA's determination there were no existing units in operation – only three under construction and five more on the drawing board. As such, the dry scrubbers addressed in *Sierra Club v. Costle* represent the most relevant comparison for the CCS systems EPA relies upon in its proposal, which are still under construction and have not yet been completed or operated.

EPA's proposal for partial CCS also attempts to draw additional support from other D.C. Circuit cases, including *Portland Cement Association v. Ruckelshaus*, which contain statements that can be pulled out of context to support EPA's effort to implement the "technology-forcing" goal of CAA section 111. However, EPA's attempt to draw support from those cases conflates the separate "achievable" and "adequately demonstrated" requirements found in the CAA section 111 definition of "performance standard." Since those cases did not actually address whether the control systems at issue were "adequately demonstrated," they are inapposite to the question of whether partial CCS "has been adequately demonstrated" for electric utility units.

EPA's proposal thus fails to respect the tension Congress intended to create by allowing EPA to push existing control systems to higher performance levels, but limiting EPA's authority to controls systems that are indeed adequately demonstrated. As such, it is an arbitrary and capricious use of CAA section 111(b), and should be withdrawn.

Ultimately, while CCS capture technology is a promising method of controlling CO_2 emissions from fossil fuel combustion, the three major avenues of doing so remain unavailable as a commercial product that can be deployed at commercial scale by power generators. CCS is, as a fundamental matter, unavailable to power generators wishing to build coal units that can comply with EPA's proposed rule.

b. There is No Material Difference Between EPA's 2012 Withdrawn Proposal and the Current Proposal

NMA agrees that EPA was compelled by comments and the CAA to withdraw the original proposed standard published on April 13, 2012,[126] and re-propose separate standards for new natural gas- and coal-fired EGUs.[127] However, NMA fundamentally disagrees that anything materially changed in the status of CCS development in order to justify EPA's new proposed coal-fired EGU standard that rests upon a finding that CCS is BSER for coal-fired units. Only 17 months transpired between the time EPA published it original proposal on April 13, 2012 and the date the Administrator signed the withdrawal notice and new proposal on September 20, 2014. None of the reasons proffered by EPA in either the withdrawal notice or re-proposal can credibly serve as new information obtained in that time period could possibly support EPA's determination that CCS is BSER for new coal-fired EGUs.

EPA's original 2012 proposal expressly stated that the agency was not proposing a determination that CCS qualifies as "the BSER adequately demonstrated."[128] Rather, the agency proposed a determination that a NGCC facility is the BSER because it has lower CO_2 emissions than a coal-fired EGU and the agency believed that "NGCC units were likely to be the predominant fossil fuel-fired technology for new generation in the future."[129] In the re-proposed rule, however, EPA pivots sharply to determine that CCS qualifies as BSER due to the purported progress of several coal-fired EGUs that are designed to incorporate CCS. However, nothing that transpired in the 17-months between the publication of

[126] 77 FR 22392 (April 13, 2013)
[127] 79 FR 1352 (withdrawal of original proposal); 79 FR 1430 (January 8, 2014)(re-proposal)
[128] 77 FR at 22420 (April 13, 2013)
[129] *Id*. at 22418

original proposal and the Administrator signing the re-proposal provides any rational basis for thinking that CCS was any closer to being adequately demonstrated for commercial deployment in the power sector. And, certainly events since the re-proposal supply no reasons for sustaining that belief.

The two projects under construction have been continuously delayed and their costs substantially increasing. The one project in the United States (Kemper) is now almost twice its initial cost with a recently revised estimate projecting it will cost $5.5 billion. The other projects EPA cites as moving forward were all in either the "Project Definition" or "Project Design" phase when the Administrator signed the re-proposal according to DOE's demonstration project update available at that time.[130] They all remain in that status according to available information.

These developments further reveal the absence of any reasonable basis for the agency's about face on CCS as BSER. The agency's re-proposal shows EPA's true intention in making a modest adjustment in the proposed standard from 1,000 lbs. CO_2/MWh to 1,100 lbs. CO_2/MWh is to achieve the same result of effectively barring new high efficiency coal plants by requiring an exorbitantly costly and unproven technology.

On the other hand, there is a basis for setting a standard that is aligned with the emission performance for SCPC and IGCC technologies without CCS. As EPA notes, utility Integrated Resource Plans show that new coal-fired generation without CCS is a technology option being considered to meet future power demand.[131] With natural gas, coal and nuclear base load power plants retiring due to age and new

[130] Department of Energy, *Major Demonstration Programs: Program Update 2013*, DOE/FE-0565 p. 3-8, Exhibit 3-4 (Sept. 2013)
[131] 79 Fed. Reg. at 1434

regulations, diminishing reserve margins and natural gas prices trending upwards, new coal-fired generation without CCS will become an attractive option – especially in regions where natural gas pipeline infrastructure remains insufficient to assure reliable same day delivery that utilities rely upon to provide reliable power generation. As EPA observes, it is "important to set standards that preserve options for fuel diversity, particularly if natural gas prices exceed projected levels." Inexplicably, EPA proposes a "separate standard" for new coal-fired EGUs beyond the reach of available technology and will guarantee the lack of generation diversity the agency professes makes a separate standard appropriate.

EPA singles out one coal-fired EGU project under development that has received all of its state permits but has not commenced construction in time and would be subject to this NSPS.[132] The agency suggests that if the project continues to proceed toward construction, it may propose a specific NSPS for that plant at a later date. Such a tortured process is wholly unnecessary if EPA proceeds in setting the NSPS lawfully based upon the performance of highly efficient SCPC technology without CCS.

On several occasions EPA refers to the declining number of new coal-fired projects, but fails to mention the outsized role the agency's policies have directly played in that decline. EPA's successive NSPS proposals this decade for mercury and CO_2 froze many projects in regulatory limbo until final standards and litigation ran their course. In the original 2012 NSPS proposal, EPA mentioned nine coal-fired projects with air quality permits that had not commenced construction. They

[132] NMA assumes EPA is referring to the Power4Georgians 850 MW Plant Washington in Georgia. The project developer executed contracts in 2013 for fabrication of the boilers

were all impaired by the prospect of standards that would impose requirements that were not within their design or beyond the capabilities of existing technology. [133] EPA cannot ignore the chilling effects of its rules that create heightened risks which cause the delay or cancellation of coal-fired EGU projects and then disingenuously rely upon the effects of the agency's regulatory actions as a rationale for an unreasoned standard.

In sum, the lack of any material developments between the original proposal and the re-proposal in the status of CCS demonstration further reveals the absence of any reasoned basis for the proposed standard.

c. EPA's Assertion About Recent Builds Incorporating CCS is Incorrect

In the proposed rule EPA also asserts that progress towards completion of both the Kemper Facility and Sask Power's Boundary Dam plant, coupled with the planned construction of TCEP, HECA and W.A. Parish justifies setting CCS as BSER for new coal-fired units. EPA then alleges that, essentially, all new coal capacity will be built with CCS in mind, stating that:

[133] EPA's Utility MACT NSPS rule effectively precluded these sources from beginning construction within the one year. As some of those transitional sources informed EPA both in petitions for reconsideration in EPA's MATS rulemaking and in the appeal of that rule, EPA's MATS rule was so stringent that pollution control vendors stated that they could not guarantee that their equipment can meet those standards. In that motion, the Institute of Clean Air Companies (ICAC), a trade association for "approximately 100 companies that comprise nearly all the suppliers of air pollution control equipment and systems as well as measurement and detection equipment," in a filing that addressed only the new-unit mercury standard, told EPA that that standard is set at a level that cannot be detected by pollution control measurement systems. As a result, "ICAC member companies are not in a position to offer commercial guarantees to their customers to meet this particular standard."[133] ICAC concluded that "[t]his standard will make it nearly impossible to construct new coal-fired EGUs because financing of such units requires guarantees from equipment suppliers that all emission limits can be met." EPA finalized its new source reconsideration in March of 2013, leaving only weeks for new unit developers to move forward prior to the April 13, 2013 deadline

> Continued progress on these projects is consistent with the EIA modeling which projects that few, if any, new coal-fired EGUs would be built in this decade and that those that are built would include CCS. The existence and apparent ongoing viability of these projects which include CCS justify a separate BSER determination for new fossil fuel-fired utility boilers and IGCC power plants.[134]

However, EPA's now rescinded 2012 proposal belies that claim. In 2012, the agency named a number of 'transitional sources' that either (1) had obtained a PSD permit or (2) were attempting to extend expired PSD permits pending receipt of DOE financial support for CCS. EPA specifically identified 15 projects that it considered to meet these criteria. Of those 15 transitional sources, six projects had CCS loan guarantees from DOE, while another nine were conventional coal units proceeding with a mix of financing sources. While the majority of both types of project – conventional and CCS equipped – have since failed, been put on hold or are switching to natural gas as primary feedstock, the plants cited by EPA in its original proposal undercut EPA's assertion that almost all new coal builds are designed with CCS in mind. Thus, EPA's own 2012 review identified that a full 60% of facilities that had obtained PSD permits were conventional SCPC, USPC or IGCC facilities that were not CCS equipped since they had not sought DOE loan guarantees to install CCS technology.

EPA's assertion about the overall move of utilities to considering CCS for new coal-fired units lacks merit, and speaks to the lack of CCS as an adequately demonstrated technology that could be considered BSER. This departure from

[134] 79 Fed. Reg. 1434

setting BSER based on commercial operating facilities with real world operations data is a fundamental flaw in the proposed rule, since industry investment patterns in new coal-fired capacity bear out that SCPC, USCPC and IGCC plants are the most logical technological progression for new coal units – patterns that EPA itself recognizes. EPA's leap to requiring CCS for all new coal-fired builds in setting BSER makes little rational sense.

VI. The Energy Policy Act of 2005 Expressly Prohibits EPA from Considering Facilities that Received CCPI Funding or Certain Federal Tax Credits in Determining BSER

On February 26, 2014, EPA published a NODA in support of the proposed rule soliciting public comment on whether certain provisions of EPAct05 limit the agency's authority to rely on information from facilities that received assistance under that Act to set BSER. Specifically, EPA requests comment on whether EPAct05 – and specifically 42 U.S.C. § 15962(i) – prevents the agency from relying on information from such facilities to determining, for the purposes of this proposed rule, that BSER has been adequately demonstrated for new fossil fuel-fired boiler and IGCC EGUs.[135] EPA interprets Sections 402(i) and 1307(b) of EPAct05 "to *preclude EPA from relying solely on* the experience of facilities that received EPAct05 assistance, but not to preclude EPA from relying on the experience of such facilities *in conjunction with* other information."[136] The agency's interpretation of EPAct05 is incorrect. Instead, EPAct05 expressly prohibits EPA from considering – alone or in conjunction with other information – the experience of facilities that

[135] NODA at 10-11
[136] TSD, "Effect of EPAct05 on BSER for New Fossil-Fueled Boilers and IGCCs," at 1-2 (Jan. 8, 2014) (emphasis added)

received government funding under the CCPI, Section 48A tax credits, or both, as evidence that partial CCS is BSER that has been adequately demonstrated.

a. EPA Cannot Consider Projects Financed by CCPI to Determine That an Emissions Standard or Technology has been Adequately Demonstrated for Regulatory Purposes

EPA's TSD argues that Section 402(i) of EPAct05 constitutes a "partial prohibition" on relying on information from facilities that receive CCPI funding in a BSER determination under CAA Section 111.[137] According to EPA, the agency is prohibited from "*relying exclusively – 'solely' – on* facilities that receive assistance under EPAct05 for purposes of determining whether a particular technology, or level of emission reduction, is adequately demonstrated."[138] In contrast, EPA asserts that it "may rely on such projects for its BSER determination *if there is additional evidence supporting such a determination*."[139] EPA's interpretation of these provisions is inconsistent with both statutory language and congressional intent. Congress did not enact a "partial prohibition" on the use of this information. Congress enacted an absolute prohibition regardless of whether the agency decides to supplement its BSER demonstration with additional information outside of EPAct05's scope.

Specifically, section 402(i) of EPAct05 prohibits EPA from considering CCS technology used or emission reductions achieved at a facility receiving CCPI funding as adequately demonstrated technology under CAA Section 111. Section 402(i) provides:

[137] TSD at 6
[138] *Id*. (emphasis added)
[139] *Id*. (emphasis added)

> *No* technology, *or* level of emission reduction, solely by reason of the use of the technology, *or* the achievement of the emission reduction, by 1 or more facilities receiving assistance under this act, *shall be considered* to be adequately demonstrated for purposes of [Section 111 of the Clean Air Act].[140]

In other words, Congress precluded EPA from considering the following three things in its BSER determination under CAA Section 111: (1) technology that receives CCPI funds; (2) the level of emission reductions achieved "solely" by reason of a technology funded through CCPI (consideration of emission reductions from *non*-CCPI funded technology is allowed); or (3) the performance of CCPI funded facilities in achieving certain emissions limits. Put simply, EPA can only consider *non*-CCPI funded facilities or technologies to support its determination that a certain technology or emission standard is "adequately demonstrated."

EPA's emphasis of the word "solely" in characterizing Section 402(i) as a "partial limitation" on the agency's authority is misdirected.[141] The word "solely" does not control the meaning of the entire provision, but merely the second clause relating to the level of emissions reductions achieved by CCPI funded technology. "Solely" does not apply to the first or third clauses in that provision, which are absolute prohibitions on relying on technology used or the performance of CCPI funded facilities. By parsing out the word "solely" and applying it to the entire provision, EPA steps outside the bounds Congress placed on the agency in

[140] 42 U.S.C. § 15962(i) (emphasis added)
[141] TSD at 6

considering CCPI funded projects in determining BSER under CAA Section 111. In point of fact, Congress spoke directly to this issue in stating that:

> [T]he use of a certain technology by any facility assisted under this subtitle or the achievement of certain emissions reduction levels by any such facility *will not result* in that technology or emission reduction level *being considered* . . . achievable, achievable in practice, or 'adequately demonstrated' for purposes of [section] 111 [of the CAA].[142]

Congress made it clear that even the *consideration* of such information is prohibited in the BSER determination process.

Furthermore, nowhere in Section 402(i) does Congress authorize an exception to this explicit limitation on EPA's authority. EPA wrongly asserts that it may rely on CCPI-funded projects because "there is additional evidence supporting such a determination."[143] Contrary to EPA's assertion, nothing in Section 402(i) allows such a reading. The existence of additional information outside projects funded by EPAct05 provisions such as Section 402(i) does not allow the agency to circumvent the broad statutory prohibition against the consideration of CCPI-funded facilities or technologies in its BSER determination. Had Congress wanted to grant EPA this flexibility, it would have included explicit language to that effect. Instead, it directs EPA against even the consideration of such projects in determining BSER.

Importantly, Congress recognized that the purpose of the CCPI program is to promote the development of technologies that are not yet adequately

[142] H. Comm. On Energy and Commerce, Report on H.R. 1640, "Energy Policy Act of 2005," H.R. Rept. No. 109-215 at 239-40 (July, 29, 2005) (emphasis added)
[143] TSD at 6

demonstrated.[144] In promoting these technologies, Congress was also careful to place limitations on EPA's ability to prematurely consider or rely on these federally funded, commercially unviable projects in setting regulatory standards under CAA Section 111.[145] Again, such projects are statutorily outside the scope of the BSER determination no matter what other information may exist.

All things considered, the interpretation of Section 402(i) put forward by EPA in the TSD would render useless the express statutory limitations Congress enacted to shield future BSER determinations from even the consideration of information from facilities or technology funded under the CCPI. This holds regardless of whether the agency tries to supplement its administrative record with other information (i.e., foreign projects, literature reviews, other domestic facilities not funded by CCPI). NMA objects to this interpretation and opposes the agency's express reliance on CCPI funded projects in determining that partial CCS is BSER that has been adequately demonstrated developed for new coal-fired EGUs in this proposed rule.

b. EPA Cannot Consider Projects that Received Section 48A Tax Credits to Determine that an Emissions Standard or Technology has been Adequately Demonstrated for Regulatory Purposes

EPA's TSD lays out a similarly flawed argument in its interpretation of how it can use information from facilities that were awarded a Qualifying Advanced Coal Tax Credit under Internal Revenue Code Section 48A in determining whether an

[144] 42 U.S.C. 15961(a) ("To be eligible to receive assistance . . . a project shall advance efficiency, environmental performance, and cost competitiveness *well beyond* the level of technologies that are *in commercial service* or *have been demonstrated* on a scale that [the U.S. Department of Energy] determines is sufficient to demonstrate that commercial service is viable . . .") (emphasis added)
[145] 42 U.S.C. § 15962(i)

emissions standard or a technology has been adequately demonstrated under CAA Section 111. According to EPA, "use of technology, or emission performance, from a facility for which the credit is allowed *cannot, by itself, support* a finding that the technology or performance level is adequately demonstrated, but the information *can corroborate* an otherwise supported determination *or otherwise provide part of the basis* for such a determination."[146] Once again, EPA's interpretation ignores the Congressional limitations placed upon the agency in considering projects that received Section 48A tax credits in determining BSER that has been adequately demonstrated under CAA Section 111.

IRC Code Section 48A subjects EPA to a broad prohibition against the consideration of any information from technologies used at facilities that are awarded these tax credits to demonstrate BSER. Specifically, Section 48A provides:

> *No* use of technology (or level of emission reduction solely by reason of the use of the technology), and *no* achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, *shall be considered to indicate* that the technology or performance level is . . . adequately demonstrated for purposes of section 111 of the [CAA].[147]

Like the CCPI provision discussed above, Section 48A prohibits the agency from considering as BSER: (1) any technology used at facilities that are awarded the tax

[146] TSD at 13 (emphasis added)
[147] 26 U.S.C. §1307(b)

credits; (2) level of emissions reductions "solely" from the use of that technology at facilities awarded the tax credit; or (3) emission reduction achievements demonstrated by the use of any technology at facilities awarded the tax credit. Simply stated, EPA may not consider Section 48A facilities in any manner – in corroboration of or in addition to other potentially permissible information – to support an adequately demonstrated determination. In short, EPA is precluded entirely from considering such information in determining BSER.

As explained above regarding the CCPI program, EPA has improperly cherry picked the word "solely," which appears in the parenthetical for only the first clause of the provision, to improperly modify the entire provision and argue that the agency has broader discretion to consider Section 48A projects. In this instance, "solely" only modifies the clause in the provision dealing with emission level reductions from technology at facilities receiving the tax credit – it does not apply to the other comprehensive prohibitions that control the agency's authority in using Section 48A facilities to make a BSER determination. EPA's attempts to confuse the meaning of Section 48A by positing various meanings of the phrase "considered to indicate" does not save EPA's erroneous interpretation.[148] Congress was clear when it enacted Section 48A that information regarding facilities funded by the Qualifying Advanced Coal Tax Credit cannot be used as part of the BSER determination under CAA section 111. EPA's express reliance on such facilities in the proposed rule is in direct violation of Section 48A of EPAct05.

c. EPA Violated EPAct05 by Relying on Projects Receiving CCPI Funds or Section 48A Tax Credits in Determining the BSER for New Fossil Fuel-Fired Boiler and IGCC EGUs

[148] TSD at 13

As demonstrated above, EPAct05 prohibits EPA from considering or relying on projects receiving certain federal assistance for the development of technologies as evidence that BSER is adequately demonstrated under CAA Section 111. EPA violated these provisions by considering and relying on the Kemper Facility, TCEP, and HECA in making its determination that partial CCS is BSER that has been adequately demonstrated.[149] All three of these facilities received CCPI assistance from DOE and were awarded Section 48A tax credits.[150] Consequently, EPA's overwhelming reliance on these three facilities in determining that partial capture CCS is BSER that has been adequately demonstrated is a violation of EPAct05, and the agency cannot consider these facilities as part of its BSER analysis in the final rule.

EPA attempts to downplay its reliance on these three facilities in the TSD. In the proposed rule, however, EPA makes clear that Kemper, TCEP, and HECA – along with the Boundary Dam Project in Canada which is not subject to EPAct05 since it is an international project – are central to EPA's determination of whether partial CCS is "adequately demonstrated" for new coal-fired EGUs.[151] Despite the agency's references to literature and other projects incorporating aspects of CCS technology, a plain reading of the proposed rule reveals that these facilities are the

[149] 79 Fed. Reg. 1434 ("The existence and apparent ongoing viability of these projects which include CCS justify a separate BSER determination for new fossil fuel-fired utility boilers and IGCC power plants.")
[150] For a further discussion of the awarding of Section 48A tax credits, please see the comments of EEI and UARG. Southern Company's Kemper Facility was awarded the tax credits, but might have to forgo them given the potential for delayed startup of the facility
[151] 79 Fed. Reg. 1433 n.4 (emphasizing the "significant progress" on the Kemper CCS project and continued progress towards construction of the TCEP and HECA projects as evidence of the changes in the electricity sector to warrant EPA's shift to partial CCS as BSER)

primary examples relied upon by the agency before determining that "CCS technology has been adequately demonstrated, and its implementation costs are reasonable."[152] Moreover, Kemper, TCEP, and HECA are highlighted as three of the four primary examples demonstrating the "technical feasibility and availability" of CCS.[153] EPA's overwhelming reliance on these projects is a direct violation of EPAct05, and is impermissible. Had EPA done a proper and thorough BSER analysis of adequately demonstrated technology – as explained at length previously in these comments – the agency could not have made a good faith determination that partial capture CCS is BSER that has been adequately demonstrated for coal-fired EGUs. As such, the proposal by the agency cannot stand as is.

VII. The Proffered Rationale for EPA's CCS BSER Finding Fits Most Major Industrial Sources of CO_2, and as a Consequence Cannot Rationally Support a Finding that it Constitutes BSER for Coal-fired EGUs But Not for Gas-fired EGUs

EPA's reasoning supporting its determination that CCS is technologically feasible for coal-fired EGUs fit most major industrial sources of CO_2 and new NGCC power plants. There is no rational basis for EPA's different conclusions that CCS has been adequately demonstrated as the best system of emission reduction for coal-fired units but not for gas-fired units. Both types of units burn fossil fuels; both produce CO_2 through the same fundamental chemical reaction; and both emit that CO_2 through identical physical systems that could equally bear the installation of CCS technology.

[152] 79 Fed. Reg. 1436
[153] 79 Fed. Reg. 1435 ("The above examples suggest that project developers who are incorporating CCS generally considered two variants: either a partial CCS system or full CCS system . . .")

In EPA's view, partial CCS is technically feasible for coal-fueled EGUs because *each step* in the process has been demonstrated to be feasible."[154] If demonstration of any "step" in any specific industrial application is the *sine qua non* for "technically feasible," EPA's reasoning would support a determination that CCS is BSER for a wide array of industrial sources of CO_2 and NGCC plants.

a. Technical Feasibility – CO_2 Capture Technology

CCS is equally unavailable for all fossil fuel-fired units, in this case coal- and gas-fired EGUs, since CCS technology is the same fundamental system for fossil units that produce CO_2 emissions in the process of producing energy. CCS technology is a three-part system, involving the capture of CO_2 at the EGU, the transportation of said CO_2 through pipelines, and finally the sequestration of CO_2 in certain geologic formations (either for EOR or in underground geologic formations). The transportation and storage elements are identical for both the coal and natural gas units that would utilize carbon capture technology, since once the unit has captured the CO_2, the transportation and storage portions are the same. Thus, any key difference would theoretically be contained exclusively in the capture element of CCS technology.

EPA's examples for technical feasibility of CO_2 capture comprise principally certain facilities capturing CO_2 from gas streams in the natural gas processing or industrial separation to produce food and chemicals.[155] The only end-to-end commercial carbon dioxide and storage facilities currently in operation do not

[154] 79 Fed. Reg. 1471. See also, *id*. ("Each of the core components of CCS—CO_2 capture, compression, transportation and storage—has already been implemented").
[155] *Id*.

engage in commercial electric power generation from coal.[156] Rather, these projects involve natural gas processing plants or industrial separation.[157] Six of the eight projects with schedules for beginning operations over the next five years also involve natural gas processing or industrial applications.[158] Apart from the differences in carbon capture technology used in these industrial applications, a typical mid-size coal-fired power plant would generate 2-4 times as much CO_2 per year, and perhaps an order of magnitude more cumulative CO_2 stored over a typical 40-50 year lifetime than these four large scale projects.[159]

EPA's assertion that it lacks sufficient information to determine technical feasibility of CCS (partial or full) for NGCC does not square with the available literature or even the literature that EPA relies upon for its proposed determination that it is feasible for coal-fueled EGUs. To begin with, the post-combustion carbon capture technology for NGCC would be similar to that used at the three small coal-fueled power plants EPA relies upon for its proposed finding that CCS is technically feasible for coal-fueled EGUs. Moreover, EPA inexplicably ignores natural gas-fired power plants and boilers currently or formerly in operation with CO_2 capture:

- Sumitomo Chemical Plant (Chiba Prefecture, Japan): natural gas fired power plant that generates electricity and uses a scrubbers system to remove CO_2 from flue gases for use in food processing. Operational since 1994.

[156] As noted earlier in these comments, the Great Plains Synfuels Plant using lignite to produce syngas for chemical production involves a capture system that is not the same as the type necessary for a coal-fired IGCC power plant
[157] Global CCS Institute, *The Global Status of CCS—2013* p. 28
[158] *Id*.
[159] A single 550 MW net output coal-fired power plant capturing 90 percent of CO_2 would need to separate approximately 5 million tons of CO2 annually

- Prosint Methanol Production Plant (Brazil): Natural Gas fired boiler using a CO_2 capture unit to use for carbonate beverages. Operational since 1997.[160]
- Northeast Energy Associates (Bellingham, MA): Natural gas-fired power plant (320 MWe) using Fluor's Econamine FG Plus to capture CO_2 from flue gases at a 85-95 percent recovery rate with CO_2 suitable for sale in the food and beverage industry. Operated from 1991-2005 and capture ceased with the increase in natural gas prices.[161]

The Report of the Interagency Task Force on Carbon Capture and Storage notes that post-combustion CO_2 capture can also be applied to the flue gas from NGCC power plants.[162] EPA also fails to consider or discuss the evaluations performed by the DOE for NGCC with CCS.[163] NETL's analysis of two NGCC units based the NGCC plant design on a market-ready technology that would be commercially available in time to support a 2010 startup date. The unit would be equipped with the Fluor Econamine Flue Gas Plus technology, which removes 90 percent of the CO_2 in the FG exiting the HRSG unit. Once captured, the CO_2 would be dried and compressed and then injected into deep saline aquifers for sequestration. DOE has updated its evaluation of the technical feasibility and costs

[160] See DOE/Pacific Northwest National Laboratory, An Assessment of Commercial Availability of Carbon Dioxide Capture and Storage Technologies, p.10 (PNNL-18520)(June 2009), *cited by* EPA at 79 Fed. Reg. 1471
[161] http://www.zeroco2.no/projects/bellingham
[162] Report of the Interagency Task Force on Carbon Capture and Storage (Aug. 2010), p. 30.
[163] Department of Energy National Energy Technology Laboratory, *Natural Gas Combined-Cycle Plants With and Without Carbon Capture & Sequestration* (May 15, 2007) ("NETL CCS Report," attached as Appendix 3), also available at http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Technology_051507.pdf

of NGCC with CCS along with the evaluations it has done for coal-fired plants.[164] And, as previously noted, this technology was successfully operated on a 320 MW natural gas power plant for 14 years.

Of course, the same technical challenges confronted by coal-fired EGUs may also apply to natural gas-fired units:

(1) Lack of demonstration at the scale necessary to establish confidence for power plant application; the capture capacities used in industrial processes and pilot projects to date are much smaller than the capacity required for the purposes at a typical power plant so there remains considerable uncertainty associated with process scale-up;

(2) High capture and compression auxiliary power loads decreasing the efficiency of the plant and yielding less power to the grid—although the efficiency penalty for a NGCC plant would be lower (perhaps half the decrease) than a SCPC plant;[165]

(3) Capture process energy integration with existing power system; and

(4) Impacts of flue gas contaminants (NO_x, SO_x, PM) on capture system—although these concerns would be negligible for NGCC given the lower level of contaminants in the flue gas (SO_2 and PM would be negligible).[166]

[164] See *Cost and Performance Baseline* reports cited by EPA at 79 FR 1471 n. 189; 1476 n. 224

[165] See DOE/NETL, *Cost and Performance Baseline for Fossil Energy Plants* (Vol 1) (DOE/NETL-2010/1397 (Rev. 2a, Sept. 2013) p. 3 & 5 (Ex. ES-2) (NGCC with CO2 capture results in the highest efficiency—42.8 percent—among all capture technologies). See also DOE, *Carbon Dioxide Capture and Storage RD&D Roadmap*, p. 24 (30% energy penalty for SCPC and 15% energy penalty for NGCC)

[166] DOE/NETL, *Natural Gas Combined-Cycle Plant (NGCC F-Class with CCS)* (Table 4) available at

EPA also relies upon the planning of several coal-fired EGUs with CCS as indicative that CCS is BSER for coal-fired EGUs. However, these developments are matched by the continued planning of NGCC with CCS. EPA ignores the continued planning and development of Shell's Peterhead facility in Scotland, which is a planned CCS post-combustion system for a 385MW NGCC unit, with the captured CO_2 being transported to the nearby Goldeneye gas field in the North Sea for EOR operations using existing pipeline infrastructure. [167] Peterhead is not the only facility EPA has studiously ignored in its BSER analysis for NGCC units. In point of fact, recent news reports from both GE-Sargas and Summit-Linde indicate that they are proceeding with natural gas CCS design and funding proposals.[168] The Peterhead, GE-Sargas, and Summit-Linde facilities are analogous to both the TCEP and HECA projects EPA cites as support for proposing to find CCS BSER for coal-fired EGUs. EPA cannot ignore the planned and developing gas-with-CCS projects when analyzing CCS for gas-fired EGUs, while at the same time crediting the planned and developing coal-with-CCS projects when analyzing CCS for coal-fired EGUs. An objective evaluation of the available information reveals that EPA's determination that CCS is technically feasible for coal-fired EGUs applies with no less force to NGCC power plants. In short, there is no reasoned basis for making

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http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Plant%20Case_FClass%20with%20CCS_051607.pdf

[167] http://sequestration.mit.edu/tools/projects/peterhead.html

[168] Available at http://www.businesswire.com/news/home/20120619005970/en/GE%E2%80%90Sargas%E2%80%90Announce%E2%80%90Alliance%E2%80%90Enhanced%E2%80%90Oil%E2%80%90Recovery#.UvujBPldWVM and http://bellona.org/ccs/ccs-news-events/news/article/summit-power-and-linde-joinforces-to-develop-ccs-for-gas-fired-power-generation.html

different findings on the technical feasibility of CCS for coal-fired and natural gas-fired power plants.

b. Costs – CO_2 Capture

According to the Interagency Task Force on Carbon Capture cited by EPA, DOE analyses indicate that post-combustion CO_2 capture on a 550 MWe net output NGCC plant would increase the capital cost of that plant by 80 percent – about the same increase that would result from employing post-combustion capture on an SCPC plant. The incremental cost increases of electricity for NGCC with CCS is significantly lower (33%) than for a SCPC plant (60%) given fuel cost estimates, lower capital costs for NGCC units, and other factors.[169]

DOE's analyses also show that for CCS:

- NGCC has the lowest total overnight cost (TOC) at $1,842/kw as compared to SCPC ($4,391/kw) or IGCC ($4,086/kw);
- NGCC has the lowest cost of electricity (COE) at $90.43 MWh as compared to SCPC ($147.27/MWh) or IGCC ($141.27/MWh); and
- The increase in the COE for NGCC would be about 45 percent as compared to 70 percent for SCPC.[170]

As a general matter, NGCC with CCS looks more favorable than coal-fired EGU with CCS considering that (1) the capital costs of NGCC turbines are roughly one-third the cost of those for SCPC units; (2) there is less CO_2 to capture, compress and store for a NGCC unit; and (3) lower natural gas prices forecasted by

[169] Task Force Report p. 33.
[170] NETL, Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases DOE/NETL-341/082312 (Aug. 2012) pp.48-50 (document cited by EPA at 79 FR 1476 n.224)

EPA will lower the overall TOC and COE for gas as compared to coal, even with CCS on those units.[171]

c. EPA's BSER Determination for Natural Gas is Flawed

As discussed extensively previously in NMA's comments, EPA is required to undertake a multipart BSER analysis in setting NSPS. CAA Section 111(a)(1) defines the term "standard of performance" to mean "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." EPA discusses its interpretation of how to determine the standard of performance in a BSER analysis at length in the proposed rule, stating:

> Section 111 provides that the EPA's central task is to identify the BSER. The D.C. Circuit has handed down case law, which we review in detail, that interprets this CAA provision, including its component elements. The Court's interpretation indicates the technical, economic, and energy-related factors that are relevant for determining the BSER, and provides the framework for analyzing those factors. According to the D.C. Circuit, EPA determines the best demonstrated system based on the following key considerations, among others:
>
> • The system of emission reduction must be technically feasible.

[171] The LCOE used by EPA in Table 6 (79 FR 1476) to compare the different technologies using CCS assumed natural gas prices($6.11/MMBtu) well above the prices EPA uses in its economic analysis

- EPA must consider the amount of emissions reductions that the system would generate.
- The costs of the system must be reasonable. EPA may consider the costs on the source level, the industry-wide level, and, at least in the case of the power sector, on the national level in terms of the overall costs of electricity and the impact on the national economy over time.
- EPA must also consider that CAA § 111 is designed to promote the development and implementation of technology. [172]

Other considerations are also important, including that EPA must also consider energy impacts, and, as with costs, may consider them on the source level and on the nationwide structure of the power sector over time. In its BSER analysis for coal units, EPA went to great lengths to prove that CCS is an adequately demonstrated technology for coal-fired units, applying the statutory factors in section 111. Tellingly, EPA states that "[i]dentifying a new supercritical unit as the BSER and requiring the associated emission limitation would provide little meaningful CO_2 emission reductions for this source category."[173] EPA then states, however, in its BSER analysis for natural gas that the identification of NGCC as BSER for natural gas units is acceptable to EPA because, in EPA's view, "its emissions profile is [already] acceptably low." EPA's logic in this instance is indefensible. Both coal-fired and natural gas-fired EGUs emit CO_2, and power generation makes up the largest single source category of CO_2 contributors in the United States. Simply declaring that the CO_2 emissions from natural gas are

[172] 79 Fed. Reg. 1462
[173] 79 Fed. Reg. 1468

already 'acceptably low' while stating the CO_2 emissions from coal are far too high for EPA to allow is contrary to the BSER factors EPA is required to consider. Since CCS technology is equally available or unavailable for both coal and natural gas, as previously discussed, if EPA ultimately determines that CCS is BSER for one type of fossil fuel-fired source, but not the other, the Agency is clearly abrogating its duties under section 111. This holds whether EPA separately categorizes coal- and gas-fired units under Subparts Da and KKKK, or whether it groups them into a single Subpart TTTT.

Further, in its discussion of setting CCS as BSER for coal units, EPA not only concedes that it must consider that "CAA § 111 is designed to promote the development and implementation of technology," but it also argues that setting CCS as BSER for coal units will "promote deployment and further development of the technology." However, EPA sets this as a false choice for utility operators. First, as EPA's statement suggests, CCS applied to coal units is technology-forcing. But the same is true for natural gas. EPA never explains why, in its view, requiring CCS of coal-fired units would promote the development and implementation of technology, but requiring it of gas-fired units would not. In fact, by offering the choice between CCS-controlled coal on the one hand and uncontrolled NGCC units on the other, EPA is instead providing a distinct **disincentive**, and likely a roadblock, to the further development and deployment of CCS technologies. Given the cost disparities, as admitted by EPA in its LCOE analysis and discussed earlier in these comments, between CCS-equipped coal units and NGCC units without CCS, the proposed NSPS simply and irretrievably incentivizes a further build-out of NGCC units and the freezing of any new investments in the development of CCS. Thus,

by effectively forcing utilities to choose natural gas over coal, EPA just as effectively frustrates the further development and implementation of CCS technology, because no one is required to install CCS on gas units. Therefore, CCS is unlikely to be further developed under EPA's proposal. In the end, should EPA determine CCS is adequately demonstrated for any type of unit, using the same analysis that it used in determining that CCS was adequately demonstrated for coal-fired units EPA would also determine that CCS is BSER for all types of fossil fuel-fired units. For EPA to do less or otherwise would be unlawful.

d. Other Considerations

EPA's proposed finding that CCS is BSER for coal-fired EGUs rests in part on what the agency believes are insignificant CO_2 emissions reductions from new advanced, higher-efficiency SCPC and IGCC units. However, EPA concedes that equipping gas-fired NGCC units with CCS **would** result in significant CO_2 emissions reductions.[174] It is well-nigh impossible to reconcile EPA's recognition that significant emission reductions could be obtained through application of CCS to NGCC units with the agency's simultaneous determination that CCS is not BSER for NGCC, particularly once one considers EPA's other underlying assumption – that most new base load power plants constructed under this rule will be NGCC. In essence, EPA is eschewing CCS as BSER for the very type of power plant that will be built in nine out of ten cases, and notwithstanding EPA's concession that requiring CCS for those plants would result in significant additional CO_2 reductions.

EPA also attempts to use the lower CO_2 concentration in the flue gas stream of natural gas combustion as a reason for not finding CCS to be BSER for natural

[174] 79 Fed. Reg. 1485

gas-fired units.[175] However, there is ample demonstration of carbon capture on NGCC plants to obviate such concerns. The lower concentrations of CO_2 in natural gas flue streams should lower the costs for carbon capture's application to NGCC in terms of capture, compression and storage, especially if new NGCC plants are operating as base load power and producing more CO_2 as a result.

EPA speculates that while most natural gas turbines will serve base load demand, others will cycle more frequently than coal-fired coal plants; EPA also states that it is unclear how part-load operation would impact the efficiency and reliability of CCS.[176] While that is a legitimate concern, it is one that applies equally to coal-fired EGUs in the real world, as their operations are subject to economic dispatch, meaning that they too will cycle their operations. Remarkably, in the proposed finding that CCS is BSER for coal-fired EGUs, EPA does not evaluate or even mention this important consideration. All of the literature EPA relies upon for its determination that CCS is BSER for coal-fired EGUs similarly (and equally incorrectly) assumes that these plants will not cycle frequently. Accordingly, the reason EPA proffers here for not finding CCS to be BSER for NGCC supports the very same finding for coal-fired EGUs.

As for EPA's concerns about water impacts, they are unfounded and do not provide a legitimate reason for distinguishing between a finding that CCS is not BSER for NGCC units and a finding that it is BSER for coal-fired EGUs. CO_2 capture increases the average raw water consumption for **all** technologies—SCPC, IGCC, and NGCC. As between SCPC and NGCC, the raw water consumption associated

[175] 79 Fed. Reg. 1485
[176] *Id*.

with addition of CCS increases by 83 percent and 91 percent, respectively.[177] A SCPC plant with 90 percent CO_2 capture would increase its water consumption by 3,452 gallons per minute.[178] As for EPA's concerns about NGCC units that use dry cooling, that concern can be addressed by a separate BSER finding for NGCC plants proposing that technology or it can be addressed as part of a BACT evaluation in the permitting process.

EPA's reasoning that an NGCC plant might be delayed more than a coal plant if NGCC plants were required to use CCS is perplexing, to say the least. EPA surmises that NGCC plants can be built more quickly than coal plants, so any delay occasioned by installation of CCS would have a relatively greater impact on NGCC plants. Simply stated, the delays involved in installing CCS should be the same, no matter the type of plant involved. Notably, EPA fails to cite **any** evidence that equipping an NGCC unit with CCS is inherently or relatively more time-consuming than it is for a coal plant. All of the technology is essentially identical; in fact, installing CCS on a coal-fired unit is likely to be **more** complex and time-consuming than installing gas on an NGCC unit, because of the need to assure that the carbon capture systems are compatible with the other emission control equipment on the coal-fired unit that are not present on a gas-fired EGU.

It is very difficult to follow EPA's final reason for not identifying CCS as BSER for NGCC power plants – "the adverse effects on national electricity prices, electricity supply and the structure of the power sector"[179] – because all of these

[177] NETL, Cost and Performance Baseline for Fossil Energy Plants (DOE/NETL-2010/1397) (rev. 2a Sept. 2013) p. 7.
[178] NETL, *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture* (DOE/NETL-2011/1498 (Sept. 19, 2013 revision) p.16.
[179] 79 Fed. Reg. 1485

considerations bear equal weight in any finding for coal-fired EGUs. To begin with, EPA's concerns about adverse effect on electricity prices, electricity supplies and the structure of the power sector would be obviated with a finding that CCS **is not** BSER for any EGU (coal or natural gas). If EPA is so confident in its forecast that few if any new coal-fired EGUs will be built even if EPA does not require that coal-fired EGUs install CCS, then EPA's concerns about CO_2 emissions from such units are unfounded, and there is no reason for EPA to promulgate the proposed rule. Moreover, even if new, higher-efficiency SCPC or IGCC plants are built without CCS, as we have explained earlier those units would have CO_2 emissions substantially lower than the older, less efficient subcritical plants they would replace.

Ironically, while EPA professes to be concerned about higher electricity prices and the effects on supply that would result from requiring CCS for gas-fired units, it does not venture any discussion about the adverse effects on prices and reliability that are almost certain to result from the less diverse generation mix that will be the consequence of requiring CCS for coal-fired units but not gas-fired ones. Instead, EPA states that it remains concerned that, absent a CCS requirement for coal-fired units, additional coal plants will not be retired. Nowhere does EPA acknowledge that additional coal plant retirements will lead to adverse effects on the reliability of the grid and to increases in the price of electricity and natural gas as the nation is denied the benefits of lower-emission coal plants that will moderate and offset any increases in natural gas prices, as happened this past winter. In short, any concerns about the adverse impacts on supply and prices are of EPA's own making. They are the result of a poorly-thought-out combination of power plant rules that have forced the accelerated retirement of base load coal plants and

that effectively bar the construction of new, higher efficiency plants that would maintain fuel diversity and supply security. In the end, EPA has it backwards. It is not a finding that CCS is BSER for NGCC that presents the greatest threats of price increases and supply constraints it now uses to eschew such a finding. Rather, it is the agency's unreasoned and unsupported finding that CCS is BSER for new coal-fired EGUs that is the greater source of these threats.

EPA has not supplied a reasoned and lawful basis for making different determinations on the technical feasibility of CCS as BSER for coal-fired EGUs but not for NGCC plants. Each of the reasons offered by EPA is lacking in any support, is inherently contradictory, and demonstrates an irrational weighting of the considerations EPA claims are central to its proposed findings. The best and only permissible course of action is for EPA to reconsider and find that CCS is not BSER for coal-fired EGUs, just as it proposes to find that CCS is not BSER for natural gas-fired units.

VIII. EPA Has Failed to Satisfy the Requirements of CAA § 111(a)(i)(A) to Assess and Account for Any Nonair Quality Health and Environmental Impact and Energy Requirements from the Proposed Standard

In setting a NSPS under section 111(a)(i)(A), EPA must account for "the cost of achieving" emissions reductions "and any nonair quality health and environmental impact and energy requirements." The U.S. Court of Appeals for the D.C. Circuit has held that this language mandates an extremely broad analysis: "[t]he language of section 111 . . . gives EPA 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 plant level in the immediate present."[180] Essentially, the Court concludes that "'section 111 of the Clean Air Act, properly construed*, requires the functional equivalent of a NEPA impact statement.*'"[181]

Conducting the equivalent of an EIS requires EPA to take into account cumulative impacts of its proposed agency action. A cumulative impact analysis is mandated by the CEQ and recognized in EPA's own NEPA regulations and guidance. CEQ, the agency Congress created to oversee the implementation of NEPA, directs that the scope of an agency EIS includes consideration of cumulative impacts.[182] Consistent with the CEQ regulations,"[183] EPA guidance defines cumulative impacts as, "impacts that are due to past, present, and reasonably foreseeable actions."[184] Furthermore, according to EPA, in assessing environmental impacts, it is necessary to assess "[t]he combined, incremental effects of human activity" rather than just the impacts of the particular action for which federal approval is sought.[185] Such effects need to be included because individual actions "may be insignificant by

[180] *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981)
[181] *Id*. at 331, quoting *Portland Cement*, 486 F.2d at 384 (emphasis added)
[182] 40 CFR 1508.25
[183] 35 Fed. Reg. 7390, 7391 (1970). It should be emphasized that CEQ does not distinguish between cumulative analysis of environmental impacts and of socioeconomic impacts. Under CEQ regulations, agencies must examine the effect of the proposed action on the "human environment." 40 C.F.R. § 1508.14 states that "[h]uman environment" shall be interpreted comprehensively to include the natural and physical environment and the relationship of people with that environment." While "economic or social effects are not intended by themselves to require preparation of an environmental impact statement," "[w]hen an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment." This applies to cumulative analysis: where socioeconomic effects accumulate from multiple actions, they must be assessed cumulatively, just as environmental effects must be assessed cumulatively. Thus, cumulative analysis is as relevant for examining socioeconomics as it is for analyzing environmental impacts
[184] U.S. Environmental Protection Agency, *Consideration of Cumulative Impacts in EPA Review of NEPA Documents* (May 1999) at 10
[185] *Id*. at 1

themselves," but may accumulate over time, from one or more sources and these cumulative effects must be taken into consideration.[186]

EPA cannot deny the far reaching nature of its CAA section 111 regulations for the power sector. In fact, the magnitude of the consequences from these regulations overshadows any previous section 111 rulemaking. This further heightens the need for a broad and rigorous examination of how this proposed action to address CO_2 emissions affects other resources - both energy and environmental. In a decision involving the section 111 standards for the limestone industry, the D.C. Circuit concluded that the "sheer massiveness of impact of the urgent regulations," had "prompted the courts to require the agencies to develop a more complete record and a more clearly articulated review for arbitrariness and caprice" than had been applied in previous cases.[187] If massiveness of regulatory impact was a concern in a limestone industry case, that concern is magnified many times over in promulgating CO_2 standards of performance for the power sector whose output is ubiquitous and central to the entire economy. Moreover, the policy-induced changes in the energy sources for electricity generation will have profound effects upon many other natural and environmental resources. However, EPA has undertaken no analysis at all of the potential environmental consequences in this proposed rulemaking.

EPA has failed to either examine or provide a sufficient assessment of the following environmental considerations:

- The increased methane emissions and their effect on climate from increased exploration, development, production and transportation of

[186] *Id*.
[187] *National Lime627 F.2d* at 451 n.126

natural gas that will follow from the increased demand from the power sector

- The impacts on land use and other environmental values from natural gas pipeline construction to supply increased demand—including new natural gas power plants
- The impacts on land use and other environmental values from the construction of CO_2 pipelines to transport CO_2 to sequestration sites or for enhanced oil recovery as envisioned under the proposed rule
- Environmental and land use impacts from permanent carbon dioxide storage as contemplated under the proposed rule.

EPA's proposed rule is part and parcel of the policy-induced changes in the energy sources for electricity generation, and it will necessarily have profound effects upon many other natural and environmental resources. EPA has failed to undertake any analysis at all of the potential environmental consequences in this proposed rulemaking.

a. EPA Fails to Examine the Impacts of Increased Methane Emissions from Greater Natural Gas Development Needed to Supply the Power Sector

The proposed standard for coal-fired EGUs is premised upon the purported "climate change" advantage of natural gas EGUs over coal EGUs at the plants themselves. EPA rejects setting a standard of performance based upon high-performing SCPC and IGCC because it would provide little meaningful CO_2 emission reductions. As previously explained in these comments, EPA is wrong since the reductions from new high performing SCPC or IGCC would be about 20 percent below the national average for the existing coal fleet, and the reductions would be substantially more as compared to the oldest subcritical plants that dominate the fleet. However, CO_2 is just one greenhouse gas, and the stated purpose of the rule is to address emissions that may contribute to climate change. Nowhere in the

proposal does EPA discuss the contributions of methane emissions to climate change and the increase methane emissions that will occur as a result of a rule that will induce greater reliance on natural gas in the power sector.

Methane is a far more potent greenhouse gas than CO_2. EPA's national greenhouse gas inventory uses a global warming potential (GWP) of 26 for methane—meaning that methane is 26 times stronger a heat trapping gas than CO_2 over a 100-year time scale. The latest IPCC value released last year reports that methane is actually 34 times stronger a heat trapping gas than CO_2 over a 100-year time scale. This is significantly higher than the value EPA uses currently. Moreover, on a shorter time scale, IPCC now estimates that methane is 86 times stronger than CO2 over a 20-year period.[188] The latest IPCC examination of the methane GWP states that the choice of the 100 year time frame is arbitrary because there is not a scientific argument for selecting 100 years over any other time period. For purposes of EPA's rule, the 20-year time frame—and the 84 GWP value—is highly relevant to the extent EPA's proposal is based upon the IPCC view that urgent action is necessary to address GHG emissions. EPA's rule induces more methane emissions from natural gas systems needed to serve the greater dependence on natural gas based electricity arising from EPA policies.

EPA is well aware that the methane emissions from natural gas systems – well sites (upstream), gas processing plants (midstream) and transmission and storage (downstream) – diminishes the so-called "advantage" over coal from a climate change perspective. The question is how much difference is there between

[188] One study provides a mean estimate of 105 for the methane GWP over the 20-year time frame. Shindell DT et al, *Improved attribution of climate forcing to emissions*. Science 326: 716-718

the GHG profile of a coal-fired EGU and a natural gas-fired EGU after accounting for methane emissions. EPA does not examine that question although it is of central importance to the stated purpose of the rule to reduce emissions the agency contends contribute to climate change.

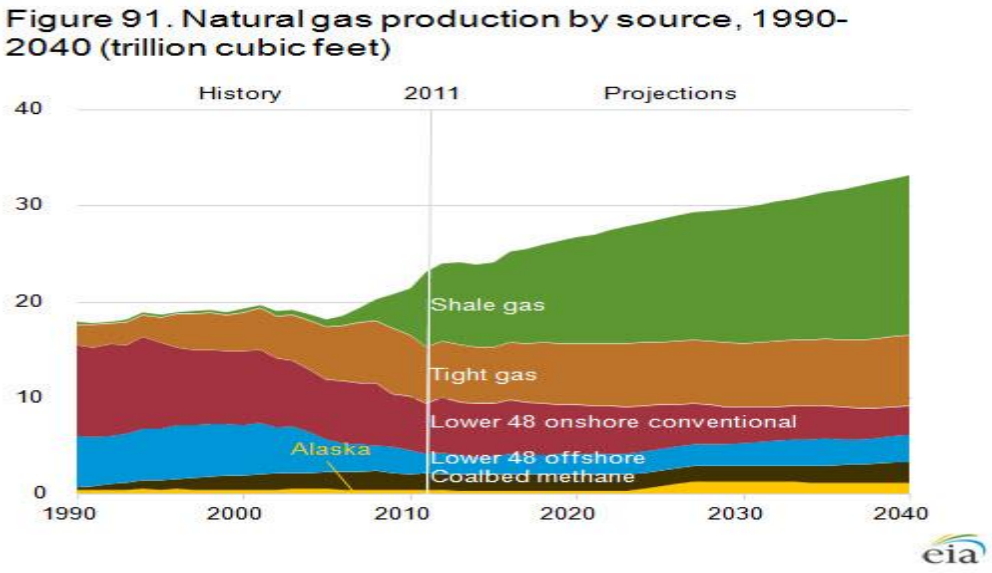
Some studies estimate that methane leakage rates from natural gas systems that exceed 2 percent erase any climate advantage for natural gas in the power sector over a 100 year time frame.[189] Others peg the threshold closer to 3 percent.[190] Yet, these estimates on the "breakeven" point for natural gas' advantage *precede* the most recent IPCC finding that methane is actually 34 times stronger a heat trapping gas than CO_2 over a 100-year time scale and 86 times stronger over a 20-year time scale.

Recent studies on methane emissions from natural gas systems vary on their findings about the amount and percentage of methane emissions from various segments of the system. While the variability may be explained by the different scope, methodology and geography of each study, most of the recent studies indicate that overall emission rates are higher than current inventory estimates.[191] For conventional natural gas, the methane emissions from upstream (well site) and midstream (gas processing plants) expressed as a percentage of methane produced over the lifecycle of a well range from 1-2.4 percent. For unconventional (shale)

[189] Wigley, T.M.L., *Coal to gas: the influence of methane leakage*. Climatic Change, 2011. 108(3): p. 601-608
[190] Alvarez, R. et al., Greater focus needed on methane leakage from natural gas infrastructure, Proceedings of the national Academy of Sciences, 2012, available at http://www.pnas.org/content/early/2012/04/02/1202407109.abstract
[191] Howarth, Shindell et al., *Methane Emissions from Natural Gas Systems*, National Climate Assessment, Feb. Report No. 2011-003 (Table 2) (Office of Science and Technology Policy, Washington, DC) available at http://www.eeb.cornell.edu/howarth/publications/Howarth_et_al_2012_National_Climate_Assessment.pdf and attached as Appendix 6

gas, the methane emissions from upstream and midstream segments is a range of 0.9-7.7 percent.[192] The methane emissions from the downstream segment of natural gas systems range from 0.07-10 percent.[193]

Unconventional gas (shale gas and tight sands) currently comprises 43 percent of total U.S. natural gas production. The DOE forecasts that it will comprise 64 percent of all production by 2020, and production of shale gas alone will increase approximately 113 percent by 2040. Unconventional gas will dominate US natural gas production and by 2040 conventional natural gas will only comprise 6 percent of total supply.[194] The growth in demand for unconventional natural gas will be driven by the increase use in the electric power sector as EPA regulations force the closure of more coal base load power plants coupled with the inability to build new higher efficiency SCPC and IGCC coal plants unless they deploy CCS in order to meet the NSPS for CO_2:



[192] *Id*. at Table 3
[193] *Id*. at Table 1
[194] Energy Information Administration, *Annual Energy Outlook 2014* (Fig. 91) (April 7, 2014)

It is more than just the differences in leakage rates between conventional and unconventional natural gas that matter in terms of methane emissions. Shale gas well production declines much more rapidly than a conventional well. The sharp decline is typically observed within the first two to three years. As a result, to maintain production in the face of more rapid decline in well productivity, new wells must be constantly drilled. With fugitive emissions occurring dominantly during well development, the shorter lifetime of a shale gas well means larger methane emissions per marketed natural gas. This reality likely explains, in part, why recent studies have found very high ambient measures of methane in shale regions regardless of leakage rates.

These are important trends and factors for EPA's consideration in assessing the efficacy of the proposed standard in addressing the stated purpose of the rule to address climate change concerns. Since unconventional natural gas will supply most of the power sector demand for natural gas, the so called "climate advantage" of natural gas EGUs over higher efficiency SCPC and IGCC appears substantially diminished, if not entirely erased. One recent study concludes that the emissions during the drilling stage for shale gas is 2 to 3 *orders of magnitude* larger than inventory estimates.[195] The mid-range of emissions from the upstream and midstream segments of unconventional gas listed in the studies discussed above exceed the two percent, and even the three percent, breakeven point for natural

[195] Caulton, Shepson, Santoro et al., *Toward a Better Understanding and Quantification of Methane Emissions from Shale Gas Development*, Proceedings of National Academy of Sciences (April 14, 2014) available at http://www.pnas.org/content/early/2014/04/10/1316546111 and attached as Appendix 7

gas' climate advantage as compared to coal-fired EGUs over a 100 year time span. Using the IPCC's latest 34 GWP for methane makes this even more apparent.

To summarize, shale gas, which has become (and will increasingly remain), the dominant source of natural gas production in the U.S. has a greater GHG footprint than conventional gas over any time scale. Shale gas used for electricity has a greater GHG footprint than coal used for electricity over the 20-year time horizon. If studies that found that shale gas used for electricity retains a GHG footprint advantage over coal-generated electricity from SCPC or IGCC were adjusted to use the most recent GWP (34) for methane and the mid-to-higher levels of methane emission rates for natural gas systems found in recent studies, the GHG footprint for shale gas electricity would be comparable to, and perhaps more than, coal-fired electricity. At the very least, such adjustments would reveal that EPA's proposed standard for coal EGUs is based upon a substantial overestimation of the potential climate benefits of natural gas compared to coal.

At the very least, the proposal evinces the agency's lack of any assessment and understanding of the overall "pros and cons" of the standard as it relates to an important emission consideration arising from its policy choices.[196] EPA's statement of reasons and accompanying analysis is devoid of any consideration of methane emissions from natural gas systems. A proper evaluation would better inform whether the proposed standard would produce anything meaningful in the way of addressing climate change. For example, when considering both the CO_2 and methane emissions, would a coal standard based upon high performing SCPC and

[196] See *Portland Cement*, 486 F. 2d at 385 (The CAA requires that the Administrator accompany a proposed standard with a statement of reasons that sets forth the environmental considerations, pro and con which have been taken into account)

IGCC result in better overall performance of the electricity system from a GHG emission perspective? NMA submits that the preponderance of the evidence answers yes based upon studies and the developments discussed above. However, EPA cannot answer that critical question since it is not analyzed in the proposal. The agency's Regulatory Impact Analysis admits that there exist significant differences in upstream GHG emissions (in particular methane) from coal and natural gas electricity technologies, but the agency states that they were not considered.[197] The agency cannot ignore the potential "counter-productive environmental effects of the proposed standard."[198]

b. EPA Has Failed to Consider Other Environmental Effects of the Proposal

There are many other environmental effects related to the proposed NSPS that EPA fails to examine. Several include:

- Groundwater quantity and quality from increased shale gas development: Shale gas production is a highly water-intensive process, with a typical well requiring around 5 million gallons of water to drill and fracture, depending on the basin and geological formation. Even with increasing volumes of water being recycled, freshwater is still required in high quantities for the drilling operations as brackish water is more likely to damage the equipment and result in formation damage that reduces the chance of a successful well. With the increasing pressure to boost well efficiencies, shale gas development demand for water grows with the development of more wells. The potential impacts also relate to pollution

[197] EPA, *Regulatory Impact Analysis* pp 5-42 and 5-43
[198] *Portland Cement*, 486 F.2d at 385

of groundwater with the return of injected fluids after fracturing and surface waters with the growing volumes of waste water destined for disposal.

- Air Quality impacts from shale development: Natural gas development, and in particular, shale gas development, present a range of air quality issues. Emissions occur at various stages of the natural gas supply chain and from various sources including the wells, trucks, drilling machinery, condensate tanks and compressor stations. Emissions include PM, ozone, NO_x and VOCs.
- Impacts from building out natural gas infrastructure to meet power sector demand for natural gas: Increasing demand in the power sector for natural gas, further enhanced by the proposes NSPS for coal EGUs, will require more natural gas infrastructure that will have direct effects on land and water resources.[199] A study by ICF projects that the US and Canada will need more than 35,000 miles of additional natural gas transmission pipelines (both mainline and laterals) through 2035 to serve anticipated growth in natural gas demand. About three fourths of the incremental growth in demand will arise from the power sector doubling its consumption as a result of EPA policies including CO_2 NSPS rules for new and existing power plants.

[199] ICF, *North America Midstream Infrastructure through 2035* (2011) available at http://www.ingaa.org/Foundation/Foundation-Reports/Studies/14904/14889.aspx

- Impacts of new CO_2 pipelines: The sequestration or use of CO_2 will require the construction of substantial amounts of new high pressure specialty CO_2 pipeline. The U.S. currently has only 6,000 miles of CO_2 pipelines.
- Water Use: The addition of an amine-based CCS system would double the consumptive water use of a power plant.[200] This increase in water consumption would have profound effects upon other water users particularly in the arid west.
- Impacts on Wildlife: Many of the environmental effects listed above will also impact various species of wildlife and fauna. There is no indication that EPA has consulted with the U.S. Fish and Wildlife under section 7 of the Endangered Species Act to evaluate whether the direct and indirect actions from this proposal will "harm" species that are threatened or endangered. Moreover, many of the areas where CO_2 sequestration will occur in deep saline aquifers run through or under ESA Habitat Conservation Plans and Conservation Banks. Has EPA asked FWS whether sequestration will be permitted in such areas?

EPA cannot dismiss the need to evaluate these and other environmental impacts arising from the proposed rule on the grounds that it does not anticipate new coal EGUs being constructed. To do so would be a frank admission that the proposal is nothing more than a policy designed to bar new coal based load electricity capacity to the nation's generation portfolio and would reveal that in fact the rule is not intended, as the agency proclaims, to promote the development of

[200] Haibo Zhai, et al., Water Use at Pulverized Coal Power Plants with Postcombustion Carbon Capture and Storage, 45 Environ. Sci. Technol., at 45:2479-85 (2011)

CCS technology. Several of these potential environmental impacts serve as barriers to future deployment of CCS if, and when, it becomes adequately demonstrated. Moreover, all of these environmental considerations, including the GWP impacts of increased methane emissions, also arise under any regulation of existing power plants.

This proposal is directly connected to the regulation of existing sources. As EPA states "the proposed rule will also *serve as a necessary predicate* for the regulation of existing source with this source category under CAA section 111(d)."[201] They must be evaluated in the context of this proposal and not deferred. The existing source regulations are more than "reasonably foreseeable" – they are, according to the pronouncements by the President and EPA, a certainty.

IX. The Proposal Lacks a Reasonable and Adequate Assessment of the Economic Effects and Energy Impacts as Required by the CAA, Other Laws and Executive Orders

The proposed standard will leave the nation's electricity supply less diverse, less reliable and more expensive. It will also lead to higher and more volatile natural gas prices for businesses and households. American businesses will be less competitive, jobs will be destroyed and families will face higher energy costs. These and other far reaching consequences arise from a rule that EPA concedes will have no quantified benefits and will produce, at best, negligible CO_2 emission changes.[202] All of this proceeds without an adequate analysis of the proposal's effects on costs, business competitiveness, inflation and energy use. The agency's

[201] 79 Fed. Reg. 1496. See also *Regulatory Impact Analysis* at 1-4. ("The proposed rule is also a *prerequisite* for the regulation of existing sources with this source category under CAA Section 111(d)")
[202] 79 Fed. Reg. 1433

assessment of these important considerations falls well short of the "extensive" analysis demanded by CAA § 317,[203] as well as other laws, Executive Orders and Office of Management and Budget guidelines.

With EPA's candid admission that the rule would produce negligible changes in CO_2 emissions and quantified benefits, the rule hardly appears in any way "necessary to carry out" EPA's function of "protect and enhance the quality of the Nation's air resources."[204] This alone makes the proposal arbitrary, capricious and beyond the delegation of authority under the CAA. The full caprice of the proposal is further revealed by the serial deficiencies in the agency's assessment of the rule's full range of impacts upon the nation's economy and energy systems.

a. The Rule's Purpose: Addressing Climate Change

The stated purpose of the proposal is to reduce CO_2 emissions to address climate change concerns. Neither the proposal nor the accompanying RIA provides any connection between the proposal and how it would help address such concerns.

EPA dedicates an entire chapter to describing climate change and its purported impacts. Yet, the agency never asserts that the proposal will either reduce GHG emission or materially change its projections of climate change effects. At best, EPA claims the rule "is designed to minimize emission of greenhouse gases, minimize the rate of increase of concentration of these gases, and therefore reduce the risk of adverse effects."[205] However, this statement is unadorned by any explanation of how the rule would actually reduce these "risks", and directly

[203] 42 U.S.C. § 7617
[204] CAA § 101(b)
[205] RIA at 3-1.

contradicts statements in the preamble that the rule *would not* decrease GHG emissions or provide any benefits.

Indeed, the absence of any connection between the proposal and addressing climate change is unsurprising when considering that:

- The proposed rule sets a standard for coal-fired EGUs that requires the use of technology which actually results in more CO_2 emissions than would otherwise occur due to the substantial parasitic load requiring a larger plant and use of more fuel to produce a comparable amount of net-electric output than a plant without CCS;
- The proposed rule sets a standard for NGCC EGUs that is already met by 95 percent of the currently operating units and the standard is 20 percent higher than the best technology deployed today;
- The proposed rule induces exclusive reliance on natural gas for future base load electricity generation and the increased demand of natural gas will result in more methane emissions that narrow, or erase, the GHG emission difference between natural gas and coal based electricity.

The type of analysis that is necessary and proper, but lacking, would evaluate direct temperature changes arising from a standard aligned with the performance of high performing SCPC and IGCC units without CCS, and determine whether the emissions from building and operating a certain numbers of those plants would make any material difference in global temperatures. It wouldn't – whether one, five or 15 such plants were built during the time frame EPA is using

for its analysis.[206] Further, if those plants replaced less efficient subcritical coal plants, the assessment would show net benefits in terms of lower emissions, job creation and stable electricity prices. Perhaps this explains the proposal's audible silence on how it will mitigate any real risks from climate change.

b. Energy Impacts and Requirements

EPA has made a sharp pivot from its historic view on the purpose of a NSPS. Previously, EPA stated that the purpose of CAA § 111 is to choose "the best system of emission reduction throughout an identified source category" and not "narrow the nation's choices for types of steam electric generation and fuel to power it."[207] Apparently, this has all changed with a proposed NSPS that requires the use of an unproven technology for base load electricity generation and, as a result, will narrow the choices for the available types of EGUs and the fuel to power it.

Diversity of fuel supply for the electric grid has served our nation and the public interest exceedingly well for both reliability and affordability. Any reminder of the real value of grid diversity is drawn from recent history – as recently as this past winter, when the grid was stretched to its operating limit. FERC acting Chair, Cheryl LaFleur, has said that skyrocketing electricity and natural gas prices this winter brought the electric grid "close to the edge" of breaking on several

[206] Importantly, more experience with these high performing coal technologies, especially IGCC, would serve EPA's stated goal to incentivize the development of new technology. These high performing coal technologies are an essential stepping stone for the eventual commercial deployment of CCS It will be the combination of perfecting higher efficiency generation technologies with efficiency and reliability improvements in carbon separation, capture and compression that will determine whether CCS can be both technically and economically viable

[207] EPA, Response to Public Comments on MATS NSPS, proposed May 3, 2011 (73 Fed. Reg. 33643, § 2 at 2 (Dec. 2011), Doc. ID No. EPA-HQ-OAR-2011-0044-5759

occasions.[208] Her colleague, Commissioner Phillip Moeller, observed that, "the power grid is now already at the limit" with so many retirements of coal base load power plants and more to come as a result of EPA's MATs rule that takes effect in 2015.[209]

Reliability

The system performance this winter clearly demonstrates the need and value of a diverse grid with coal base load as its backbone. Coal-fired plant availability far exceeded gas-fired plant, wind and solar availability and provided much needed system stability and reliability. As John Sturm of the Alliance for Cooperative Energy Services informed FERC during its recent technical conference on winter grid performance, "The unreliability of gas, wind and solar provided the lesson that fuel diversity is needed for reliability as well as for other policy reasons."[210] Days later, FERC Commissioner Moeller informed the Senate Energy and Natural Resources Committee that:

> Our latest winter exposed an increasingly fragile balance of supply and demand in many areas. Prices at times were extraordinarily high. The experience of this winter strongly suggests that parts of the nation's

[208] Lynn Garner, *FERC Conference Highlights Problems of Using Natural Gas for Electric Generation* (BNA April 1, 2014). See also, Winter 2013-2014 Operations and Market Performance, FERC Docket No. AD 14-8-000 Technical Conference (April 1, 2014) (transcript at 6) available at http://www.ferc.gov/CalendarFiles/20140424112341-Transcript0401technical.pdf

[209] *Id*.

[210] John Sturm, Vice President, Alliance for Cooperative Energy Services, Winter 2013-2014 Operations and Market Performance, FERC Docket No. AD 14-8-000 Technical Conference (April 1, 2014) available at http://www.ferc.gov/CalendarFiles/20140401084237-Sturm,%20ACES.pdf

> bulk power system are in more precarious situation than I had feared in years past.[211]

At the same hearing, Nick Akins, Chairman & CEO, American Electric Power, testified that the "weather events experienced this winter provided an early warning about serous issues with electric supply and reliability."[212] He noted that 89 percent of the coal capacity AEP will retire in 2015 due to EPA's MATS rule was called upon to meet electricity demand this winter.[213] Mr. Akins warned that this reliability concern is imminent and EPA's GHG NSPS could make matters worse.[214] Anthony Alexander, CEO, First Energy, recently commented that EPA rules will lead to less reliable service over time and that the EPA NSPS rules for power plants could have an impact similar to the UMATs rules that have brought the electric grid to the edge.[215]

Price

This past winter natural gas prices surged to all-time highs on the East Coast as well as other regions of the country. Natural gas prices rose to a high of $90mm/BTU at the delivery point in New Jersey on January 7, 2014. Trading hubs for South Carolina saw spikes to $95mm/BTU. While it is certainly not unusual for

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[211] *Keeping the Lights on—Are we doing enough to ensure the reliability and security of the U.S. electric grid?*, Senate Energy and Natural Resources Committee, Statement of Philip Moeller, FERC, p. 2 (April 10, 2014) available at http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=0174cd0a-9066-434c-aba4-e4ceb82cf444

[212] Id. Statement of Nick Akins, p. 4 available at http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=366e6685-92f5-4878-a90f-253efa4495e8

[213] *Id*. at 2

[214] *Id*. at 4, 14

[215] Anthony Alexander, *Government Policies are Impacting Electric Service*, presentation to CEO Leadership Series, U.S. Chamber of Commerce (April 8, 2014) available at https://www.firstenergycorp.com/content/fecorp/newsroom/featured_stories/AJA-Chamber-Speech.html

natural gas prices to rise during the winter months, these prices are historic highs during a winter that was not as severe in terms of either cold temperatures or prolonged duration as the winter of 2004 that brought the previous highs of $58.52mm/BTU.[216]

Electricity price spikes followed natural gas price increases with prices reaching $2,000/MWh in the East and Midwest. In Texas, the heart of natural gas production, electricity prices reached a high of $5,000/MWh.[217] The Mid-Atlantic power pool incurred a cost of a half-billion dollars in additional payments to generators in order to keep the lights on for the 13-state region.[218] A less diverse electricity grid driven by policy-induced closures of coal power plants has been cited as a principal driver in the increase in electricity and natural gas prices.[219] Were it not for coal-fired base load power, the electric reliability and enormous price increases would have been far worse. Southern Company reported at the end of April its coal-fired generation increased during the first quarter of 2014 to 45 percent of its generation – a significant increase from 32 percent in the same period in 2013. Southern's natural gas-fired fleet generation dropped to 35 percent from 47 percent. Luckily, the fuel diversity of Southern's fleet allowed them to ramp up

[216] *New York Spot Natural-Gas Prices Rise to Record as Cold Approaches*, Wall Street Journal, Jan. 6, 2014 available at http://online.wsj.com/news/articles/SB10001424052702303933104579304452246495282.
[217] Id.
[218] Lynn Garner, *FERC Conference Highlights Problems of Using Natural Gas for Electric Generation* (BNA April 1, 2014).
[219] See, e.g., *Keeping the Lights on—Are we doing enough to ensure the reliability and security of the U.S. electric grid?*, Senate Energy and Natural Resources Committee, Statement of Philip Moeller, FERC, p. 2 (April 10, 2014) available at http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=0174cd0a-9066-434c-aba4-e4ceb82cf444.; Matthew Wald, Coal to the Rescue, but Maybe Not Next Winter, NY Times, March 10, 2014 available at http://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html?_r=0.

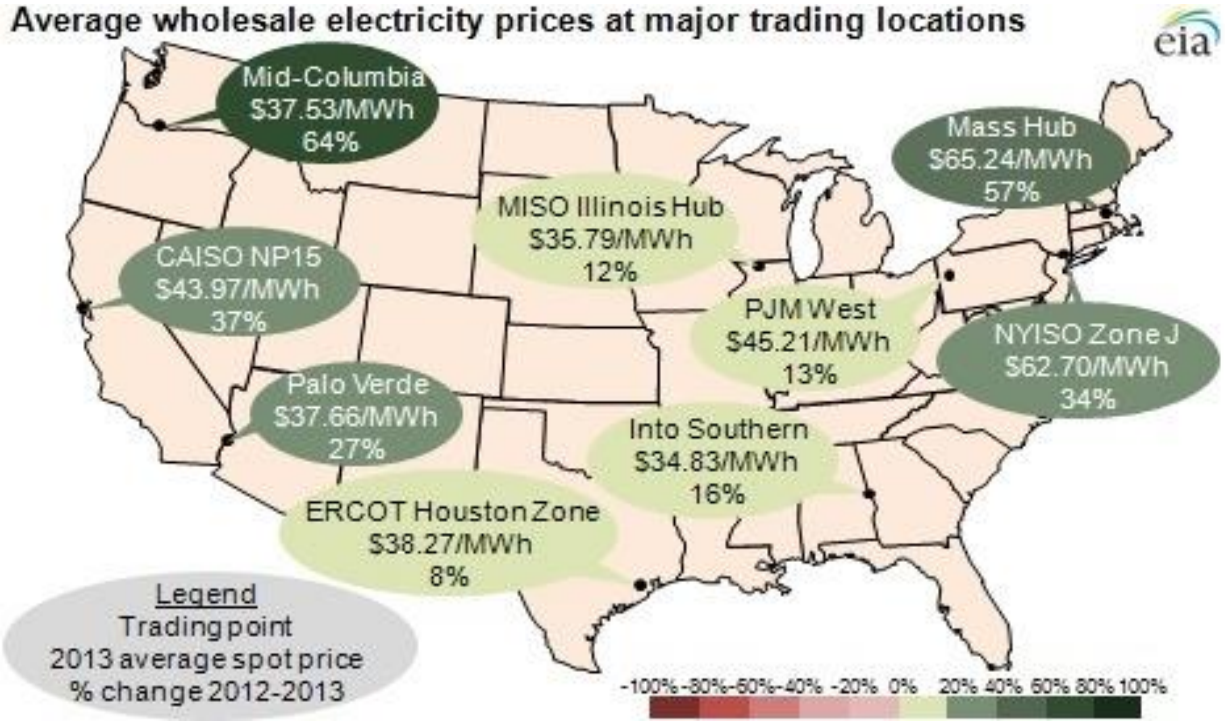
coal-fired generation and save its customers $100 million in the first quarter alone.[220]

One cannot simply dismiss these warning signs about the reliability and affordability consequences of a less diverse electric grid as a one-time seasonal event. As Michael Kormos, Executive VP for Operations at the PJM Interconnection informed FERC:

> Because less expensive coal generation is retiring and is being replaced by demand response or other high energy cost resources, excess generation will narrow and energy prices could become more volatile due to the increasing reliance on natural gas for electricity generation.[221]

Even before this past winter, natural gas prices were steadily increasing and with them electricity prices across most regions. As illustrated in the map below from EIA, even nominal year-over-year natural gas price increases between 2012 and 2013 pushed up electricity prices nationwide. Notably, the regions with the highest increases are those with a less diverse generation mix – a mix dominated by natural gas-fired generation. The regions with the smaller electricity price increases rely primarily on coal-fired base load generation. However, EPA policies are making these lower cost coal-fired base load regions more vulnerable to both steady and volatile swings in natural gas prices that plague the other regions with a heavy reliance on natural gas:

[220] Southern Company reports first quarter earnings, available at http://www.southerncompany.com/news/iframe-pressroom.cshtml
[221] Michael Kormos, Executive VP, PJM Interconnection LLC, Winter 2013-2014 Operations and Market Performance, FERC Docket No. AD 14-8-000 Technical Conference (April 1, 2014) Statement at 13, available at http://www.ferc.gov/CalendarFiles/20140401084122-Kormos,%20PJM.pdf



Source: EIA

Before this recent winter, analysts were already forecasting a steady climb in natural gas prices going forward. JP Morgan projects that natural gas prices will climb to $8 mm/BTU by 2016 – less than two years from now.[222] This is far higher than the assumptions EPA uses over a longer period of $5.31 by 2022.[223] Natural gas was priced at $6.00 as of Feb. 14, 2014 – already 13 percent higher than EPA's price assumption for natural gas six years from now.[224] Further, these recent forecasts of steadily rising natural gas prices appear too low in view of recent

[222] *Long-term gas prices poised to jump on global demand, economy: JP Morgan exec.*, Platts, Sept. 10, 2013
[223] EPA RIA at 5-48 n. 82.
[224] The delivered price of natural gas to the power sector averaged $7.01/MMBTu in February 2014

estimates of natural gas demand. ConocoPhillips projects domestic natural gas demand will exceed DOE/EIA's projection by **30 percent** in 2017.[225]

Natural Gas Demand in the Power Sector

EPA's assessment on the impact of its proposal relies upon flawed modeling and assumptions that produce a static default assumption that no new coal-based power would be built even in the absence of this proposal. In many ways, the analysis is similar to that used by EPA for its MATs rule when the agency badly missed the mark by a factor of *six* in projecting that only 9,000 MW of coal based load capacity would be retired.[226] Many other experts had forecasted the MATs rule would induce the retirement of at least 60,000 MW and other forecasts were higher than 70,000 MW by 2020 or soon thereafter. As of February 2014, nearly 50 GW of existing coal capacity has already retired or been announced for retirement by 2015.

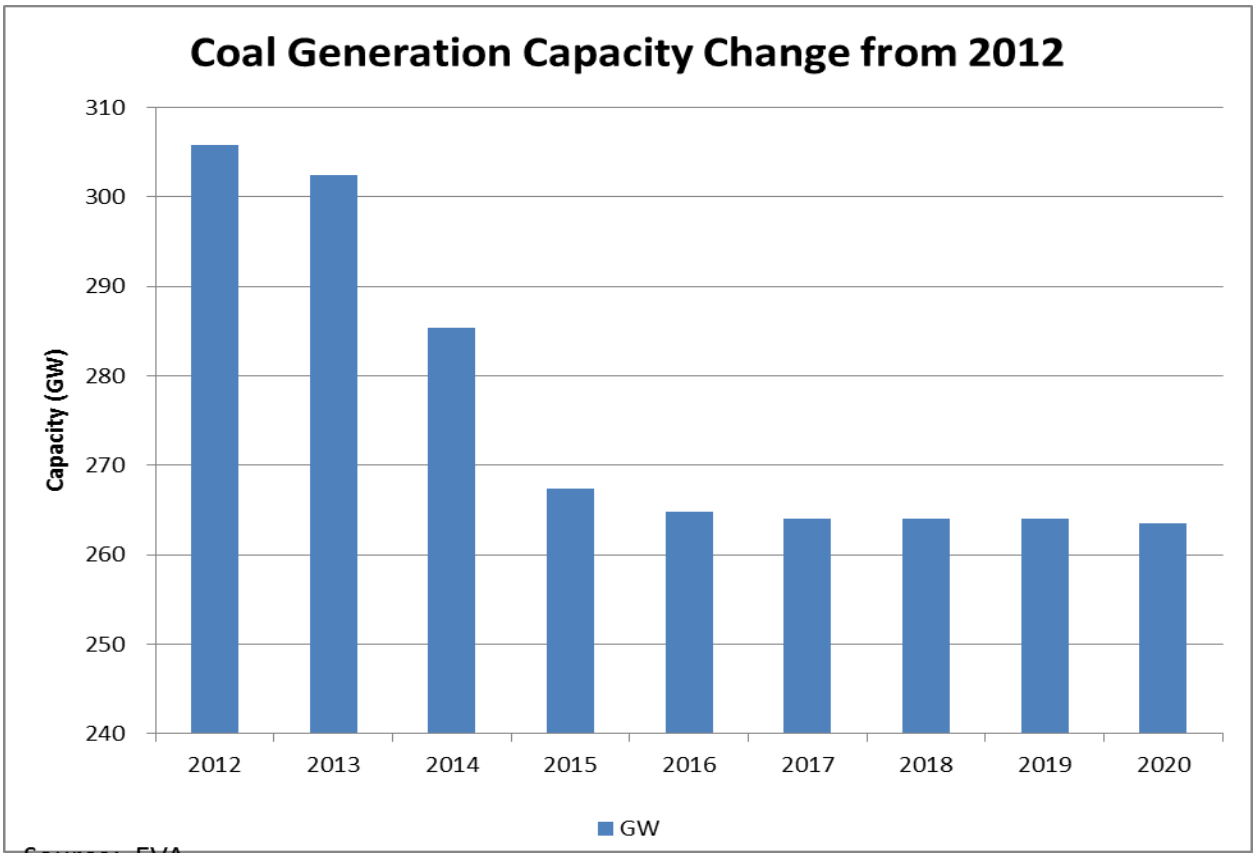
The Brattle Group estimates that there would be 59,000 to 77,000 MWs of coal capacity retirements by 2017. Brattle finds that:

> In the eastern PJM Interconnection LLC considering only the impacts of retirements on power supply curve, we estimate the increase in energy prices to be around $3-44/MWh for on-peak hours and $1-2/MWh for off-peak hours. If incremental gas-fired generation were to replace essentially all of the retired coal (a strong assumption, as some of it could go to existing coal and new renewables), then we would expect 5-10% higher gas prices that would further push PJM electric prices to

[225] *Increasing demand to shift to forefront of gas story: ConocoPhillips analyst*, Platts, Sept. 11, 2013 available at http://www.platts.com/latest-news/natural-gas/chicago/increasing-demand-to-shift-to-forefront-of-gas-21540783
[226] 77 Fed. Reg. 9304

as much as $9-11/MWh for on-peak hours and $5-6/MWh for off-peak hours."[227]

An NMA commissioned analysis from Energy Ventures Analysis (EVA) projects that, by 2020, nearly 67,000 MW of coal capacity is likely to be retire due primarily to the MATS regulations with most of the retirements coinciding with the compliance timeframe for MATS-2014-2016.[228]



Source: Energy Ventures Analysis, 2013

Most of these coal plant retirements will occur in regions where the reserve margins are already tight. Many of these regions will be forever exposed to rising

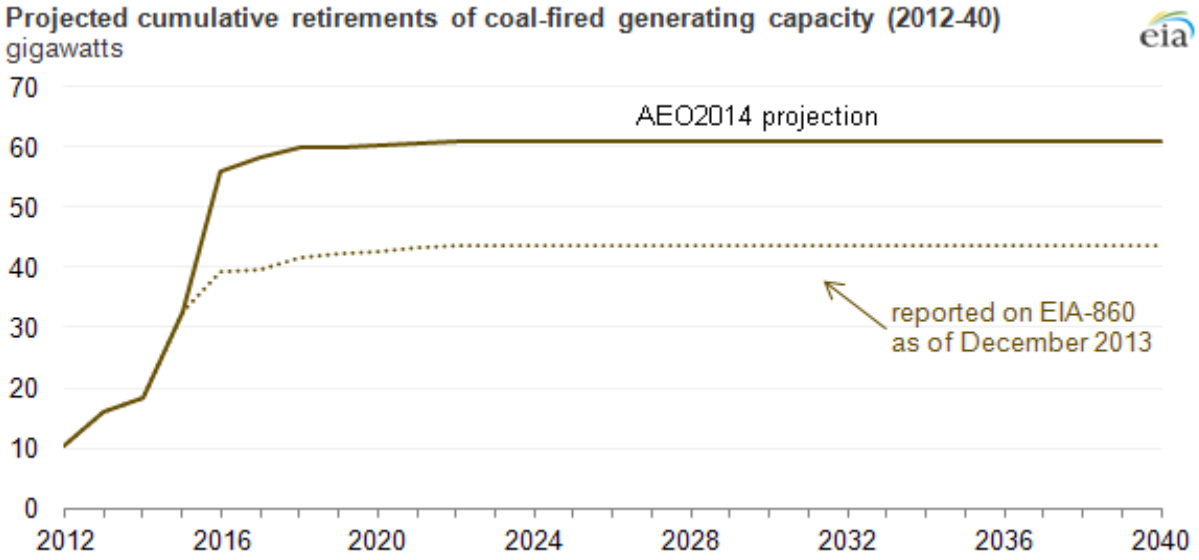
[227] "Coal Plant Retirements: Feedback Effects on Wholesale Electricity Prices," report by The Brattle Group, November 2013.
[228] The analysis uses EVA's Integrated Fuel and Electricity Model developed to calculate lowest cost compliance measures, changes in power generation and mix, plant retirements/new construction and retail electricity market impacts for different scenarios. Fuel market prices are a model output not an input and market price elasticity effects are incorporated for both electricity and natural gas consumption.

and more volatile natural gas prices as the power sector demands more natural gas. As the map below shows, the largest reduction in coal base load capacity will occur in states with the highest concentration of manufacturing as measured by manufacturing share of state GDP.[229] It is far from coincidental that states with the highest concentration of manufacturing are states where coal-fired electricity is the predominant source of base load power. EPA's policies will impair the global competitiveness of manufacturers in these states by (1) increasing their electricity costs; and (2) leaving them vulnerable to higher and more volatile prices for the natural gas they need as feedstock for their products and production processes:

Source: Energy Ventures Analysis, 2013

[229] National Association of Manufacturers, US Manufacturing Statistics, available at http://www.nam.org/~/media/36FEC7FD518342259F02B79F0AB1F809/MFG_GSP_FactSheet_Nov2013.pdf

EIA recently updated its forecast to increase its projected coal power plant retirements to 60,000 MW of existing capacity.[230] Unlike the retirements between 2010 and 2012 that were on average the smaller and oldest plants, the plants scheduled for retirement over the next 10 years are larger and more efficient with an average size 50 percent larger than recent retirements and lower average heat rates of 10,398 Btu/kWh:[231]



Source: EIA AEO 2014

EPA has often dismissed the impact of its regulatory policies on coal plant retirements suggesting they are almost entirely a product of low natural gas prices. However, recent trends demonstrate that EPA's view is based upon a lack of understanding of economic dispatch of electrical generation assets – or instead on its preference to disrupt this market principle by policy. When natural gas delivered prices to electric utilities fell to their recent lows in 2012 (April 2012 @ $$3/12

[230] EIA, *AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled*, http://www.eia.gov/todayinenergy/detail.cfm?id=15031
[231] *Id*.

MM/Btu), coal and natural gas generated roughly the same amount of electricity (Coal-96.3 TWh vs. Gas 94.8TWh) nationwide. However, less than one year later in Feb. 2013, with natural gas prices at $4.30 MM/Btu, coal generation increased by almost 30 percent (123.8TWh) while natural gas generation decreased by almost 16% (79.9TWh).

In short, natural gas prices are a temporary cyclical factor while coal-fired plants can run at higher or lower capacity factors depending upon overall demand and the relative price of coal and natural gas. On the other hand, EPA policies that force the retirement of coal base load power plants are permanent features – and EPA's proposed NSPS poses a permanent structural barrier to assuring the electric grid remains diverse enough to minimize both reliability crisis and higher and more volatile prices that reverberate throughout the economy writ large. As DOE warned in 2009, "policies that encourage the use of natural gas to substitute for coal in power generation could very well lead to spectacular price increases for households and industry."[232] That assessment turns out to be most prophetic.

EPA's view that the unprecedented size of coal EGU retirements are a product of natural gas prices and not the agency's policies is also directly refuted by a study performed by Duke University Nicholas School of Environment. According to the Duke study, "most of the planned [coal plant] shutdowns are more a response to the stricter regulations than to low natural gas prices."[233] Without the MATS rule, only 9 percent of the current coal capacity was economically threatened when

[232] DOE/NETL, *Natural Gas and Electricity Costs and Impacts on Industry*, DOE/NETL-2008/1320 p. 11 (April 28, 2008)
[233] Pratson, Lincoln F., Drew Haerer, and Dalia Patino-Echeverria, "Fuel Prices, Emissions Standards, and Generation Costs for Coal vs Natural Gas Power Plants," *Environmental Science & Technology*, 47 (9) pp. 4926-4933 (March 15, 2013), Attached as Appendix 4

natural gas prices dropped to their lowest in 2012.[234] Furthermore, the authors found that:

> Coal plants would again become the dominant least-cost generation option should the ratio of average natural gas to coal prices (NG2CP) rise to 1.8. In fact, the NG2CP is predicted to rise back up toward 2 by 2020. In the absence of EPA rules, this would result in >85% of the current coal fleet capacity once again having a lower COE than the *cheapest* natural gas plant.[235]

In February 2012, the month before the study was published, the price of coal for electricity generation was $2.38 MM/Btu and the price for natural gas was $3.38 MM/Btu for a NG2CP ratio of 1.4. At a ratio of 1.8, the price of natural gas would be at $4.28/Btu.[236] The 1.8 NG2CP ratio has been exceeded for 15 of the last 16 months between Nov. 2012 and Feb. 2014.[237] As of February 2014, the cost of natural gas delivered to electric utilities was $7.01 MM/Btu as compared to coal prices of $2.33 MM/Btu for a ratio of 3.03.[238]

The authors of the Duke study also find that, with EPA regulations, natural gas prices to utilities can increase to more than four times the coal price (NG2CP of 4.3) and remain competitive with coal plants.[239] In other words, EPA's finalized MATS regulations have made natural gas plant dispatch much less sensitive to the rise in natural gas prices. Ultimately, this means higher electricity bills for

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[234] *Id*.
[235] *Id*.
[236] For 2013, the average cost of coal delivered to electric utilities was $2.38 MM/Btu. EIA, Electric Power Monthly, Table 4.2 (April 2014) available at http://www.eia.gov/electricity/monthly/index.cfm
[237] *Id*.
[238] *Id*.
[239] Pratson et al., *supra*

customers due to the diminishing coal capacity available to moderate electricity prices. The proposed NSPS for new coal EGUs essentially locks in that outcome.

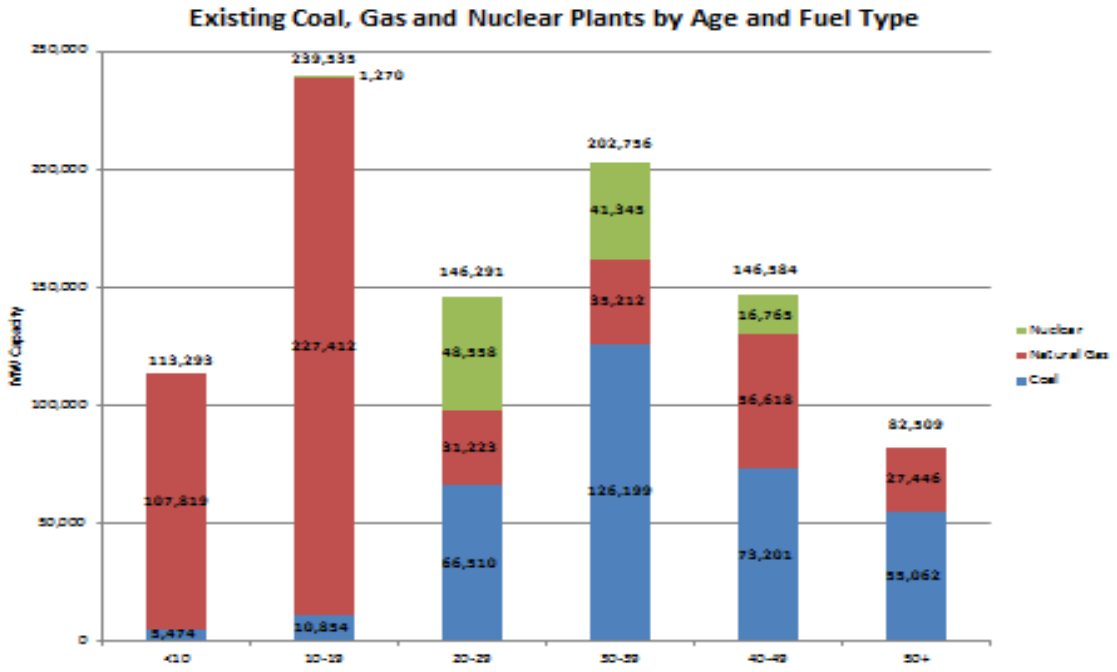
Demographics of Entire Base Load Electricity Fleet

The unprecedented closure of coal base load EGU capacity is not the only development affecting the future reliability and affordability of the electric grid. Since 2010, the 23,714 MW of capacity retirements of natural gas (12,167 MW), nuclear (4,200) and oil (6,793) electricity plants have exceeded the 19,472 MW of coal capacity during this period.[240]

Presently, approximately 25 percent of the coal, natural gas and nuclear base load capacity is 40 years or older. The capacity of natural gas plants and coal plants are roughly equal in the 40-plus years demographic. Within ten years, the 40-plus years demographic will increase to about 50 percent of the *entire* base load fleet. It is clear that, going forward, new coal plant additions will be necessary to maintain system diversity, reliability and affordability. As the chart below illustrates, absent new coal additions, the base load electricity fleet will become a narrow and rigid natural gas monolith that provides less flexibility[241] and less competition to deliver power and restrain large price increases:

[240] The 5,500 MW of nuclear capacity currently under construction will barely offset the nuclear capacity that has closed or is scheduled for closure between 2012 and 2019. In short, nuclear capacity will struggle to maintain its current 18-20 percent share of electricity generation. This will place even more upward pressure on natural gas prices since the older nuclear plants have lower variable operating costs which assures they are dispatched when available

[241] Unlike coal and nuclear plants that store their fuel on site, natural gas plants take their fuel on a daily basis from pipelines. This variability for availability of natural gas is motivating certain regional grid operators to treat some natural gas capacity like wind and solar intermittent sources in their planning for future capacity needs



None of these trends and what they portend has been factored into EPA's analysis. EPA's analysis relies almost exclusively upon EIA Energy Outlooks that *predate* EIA's substantial upward adjustment to coal and nuclear plant closures. Moreover, as we explain below, the EIA forecasts consistently inaccurate and overoptimistic in forecasting natural gas supply and prices.

c. EPA's Cost Benefit Analysis is Neither Robust Nor Credible

EPA's entire analysis of economic effects and energy requirements rests upon a single assumption – no new coal-fired EGUs without CCS would be built even in the absence of the proposed standard. In short, by requiring unproven and exorbitantly expensive CCS technology, the proposal assures that EPA's "no new coal-fired EGUs" prediction becomes a self-executing reality. EPA never explains explicitly why the CCS-conditioned standard for new coal-fired EGUs is even necessary if no new coal EGUs will be built during the analysis period (through

2022).[242] A standard aligned with the performance of high performance SCPC and IGCC (or even no standard), would result in the same impacts as the proposed standard – no measurable CO_2 emission changes – and leave a valuable generation option available if EPA's economic effects and energy requirements assessment prove incorrect. Moreover, the agency would still retain the option under the CAA of revisiting and changing a SCPC and IGCC without CCS standard if CCS technology became adequately demonstrated and economically viable in the meantime.

EPA largely relies upon EIA forecasts reflected in the in EIA's Annual Energy Outlooks from 2009-2013. However, there are several significant and fundamental problems with using EIA's modeling and forecasts. First, EIA's projections, particularly for natural gas supply, price and power sector consumption are notoriously inaccurate and overoptimistic. Overestimating the supply capabilities of the natural gas network and underestimating the price response results in a substantial underestimate of the potential costs of EPA's proposal. Second, the forecasts used in the EPA RIA do not account for the changes in the electric fleet composition described earlier. These forecasts do not reflect EIA's recent adjustments to the coal and nuclear retirements, nor the price response recently experienced over the past two years that exceed EIA's prior forecasts.[243] They also do not reflect new demand projections from the conversion of more of the

[242] RIA, at. 2-3 (stating that "all analysis is presented for compliance through the year 2022")
[243] The need to update the analysis is evident from the reference to power sector natural gas prices of $3.44/MMBtu in 2012. RIA at 4-32. Natural gas prices for the power sector exceed that price for both 2012 ($3.74) and 2013 ($4.50); and for the first two months of 2014 they have averaged between $6,00 to $7.00/MMBtu

transportation fleet to compressed natural gas or the export of liquefied natural gas to international markets.

EIA Forecasts are Historically Overly Optimistic and Reflect Systematic Bias

It has become increasingly apparent for some time that EIA forecasts for natural gas differ substantially from outcomes. A striking example of this difference is in 2002 when EIA projected the cost of natural gas to electric utilities in 2006 would be $3.82 per thousand cubic feet (Mcf) (2006 dollars). The actual cost was $7.12. Further, in 2003 EIA overestimated domestic production in 2006 by almost 2 trillion cubic feet – more than the annual natural gas production of natural-gas rich Oklahoma.

These problems are systemic. An error-decomposition analysis of one-, two-, three-, and four-year-ahead forecasts by EIA from 1998 to 2006 revealed that:

- On average, a one-year ahead- average percentage forecast error for wellhead natural gas prices of 16 percent with the errors steadily increasing to more than 45 percent with the four-year-ahead forecast. More than 54 percent of the errors for the one-year-ahead forecasts can be attributed to systematic bias;[244]
- Natural gas consumption in electric generation is consistently below actual observations. The absolute error for the one-year-ahead forecast was

[244] Considine and Clemente, "Betting on Bad Numbers," p. 55, *Public Utilities Fortnightly* (July 2007) available at http://www.fortnightly.com/fortnightly/2007/07/gas-market-forecasts-betting-bad-numbers

more than 900 billion cubic feet—more than 15 percent of consumption in the electric sector for that year;[245]

- Dry natural-gas production is consistently over-predicted. The absolute errors are quite sizeable. The two- through four-year-ahead forecast errors exceed one trillion cubic feet.[246]

The analysis indicates that the forecast errors are not reflective of random chance. Rather the forecasts contain evidence of systematic bias, either arising from a fixed, linear bias or from a systematic error coming from the NEMS model.[247] These biases emerge over a much shorter period (4-year horizons) than the 10-year plus scenarios that EPA is conducting for this rulemaking. The prospect of even greater errors on the critical factors of natural gas supply, power sector consumption and natural gas prices is highly probable, if not a certainty.

EIA AEO 2006-2013 Do Not Reflect Actual Conditions and Policy Induced Changes in the Electricity Markets

In the RIA, EPA observes that natural gas conditions did not change substantially in AEO 2013 from AEO 2012.[248] This observation highlights the fundamental problem: actual conditions did change which further confirms the inherent unreliability of EIA's forecasts. EPA observes that delivered natural gas prices to the power sector dropped between 2011 and 2012, and that "EIA projections of future natural gas prices assume trends that are consistent with

[245] *Id*. at 56
[246] *Id*. EIA's AEO Retrospective Review confirms that its reference case has a tendency to *significantly* underestimate of the natural gas wellhead price, and from AEO 2000 to the present electricity prices were *almost always underestimated*
[247] *Id*. at 57
[248] RIA at 4-32

historical and current market behavior."[249] The delivered price of natural gas to the power sector began to increase again in 2013 ($4.50/MMBTu). In the first two months of 2014, the delivered price breached $6.00/MMBTu and during February reached $7.01/MMBTu – *well above* EIA's previously forecasted price for that same time period. AEO 2013 did not project delivered natural gas prices to the power sector to reach $7.00 until 2035 – a projection that was proven inaccurate by a mere 21 years. AEO 2014 appears equally inaccurate and obsolete since the reference case pegs delivered natural gas prices reaching $7.00 in 2035 – about the same time as AEO 2013.[250] We have reached the $7 price point two decades earlier than EIA forecasts.

Both the AEO 2013 and AEO 2014 reference cases contain dubious and unsustainable projections. These include:

- The projected demand for natural gas is significantly underestimated. EPA, as well as energy analysts, predicts that natural gas demand will increase substantially to replace the lost generation from current and projected coal plant retirements and higher consumption from the industrial sector as additional manufacturing capacity in gas-intensive industries come to the US in the face of higher natural gas costs in Europe and Asia. AEO 2013 and 2014 forecast a natural gas demand increase of 7 percent between 2013 and 2022. Our analysis indicates that the combination of increased power and industrial sector consumption will increase demand in that period by 15 percent – a 1.83 Tcf difference from

[249] *Id*.
[250] EIA, AEO 2014 Table A3, Energy prices by sector and source (April 7-30 Release Dates) available at http://www.eia.gov/forecasts/aeo/

the EIA estimate.[251] Our analysis and EIA's forecast begin to diverge by 1 Tcf by 2014 with that gap beginning to widen in 2020. All of this coincides with the increased coal plant retirements in 2014 through 2020. At a minimum, EPA must look at the retirements of coal-fired EGUs that are known and forecasted and calculate the natural gas requirement to replace that generation. After all, EPA states in its proposal that it anticipates that most of the lost coal generation will be filled by new natural gas-fired EGUs and increasing the capacity factors at existing natural gas-fired EGUs. It must also look closer at more recent analysis on growing industrial sector consumption;

- The forecasted natural gas prices are too low to support the supply growth rate AEO 2014 forecasts, and are well below levels necessary to sustain the supply growth other analysts peg at twice the level forecasted by EIA. With shale gas comprising a greater share of overall supply in all forecasts,[252] neither AEO 2013 nor 2014 account for the steep decline rates for shale wells and the impact on ultimate recovery. The steep decline rates require a constant drilling treadmill of more expensive wells at a faster pace just to maintain current production levels. The recent

[251] EPA can readily calculate the potential increase in natural gas demand for the power sector. By tabulating the power plants that have announced plans to close and those likely to close (available in various analysis available over the past three years) and then calculating the amount of natural gas needed to replace the "retired" coal generation from a base year such as 2011. Thomson Reuters North America Natural Resource Team calculated a 1.9 bcfd natural gas requirement to replace coal generation retired by 2018. See Julia Edwards, Reuters "Analysis: Supply test looms for darling natural gas" (Jan. 30, 2014) available at http://articles.chicagotribune.com/2014-01-30/business/sns-rt-us-usa-naturalgas-demand-analysis-20140130_1_natural-gas-prices-more-gas

[252] Shale gas grows as a percentage of all supply as a result of a combination of increased shale production, declining production of conventional gas and declining natural gas imports. About one-third of the shale gas supply offsets the decline from other sources.

shift of drill rig deployment from dry gas to oil and liquid rich reserves is one of several signals that prices are inadequate to sustain the replacement rate.[253] Some analysts have concluded that gas prices in the range of $8.00 to $9.00/Mcf are required to break even on a full-cycle basis.[254] Notably, the growth rate of dry gas production has slowed since 2011 with lower pricing. In 2013, the growth rate was less than 1 percent.

EPA notes the possibility of significant variation in projections and actual prices, but suggests that EIA's range of alternative cases "address many of the uncertainties inherent in *long-term projections*." However, the significant variations we are already seeing are occurring in the *short-term* which further confirm that EIA's forecasts and its NEMS model are not sufficiently sound for assessing the economic effects of EPA's proposal or for guiding wise policy choices. Running "alternative cases" does not address the fundamental errors in assumptions and systematic bias in the models.

EPA Misunderstands and Misapplies the Domestic Natural Gas Resource Base

EPA's assessment of energy requirements and available natural gas supply reflects a fundamental misunderstanding about the distinction between resources and reserves. EPA uses EIA's AEO 2012 estimates that the U.S. possesses 2,214

[253] Major companies taking significant write-downs of the value of shale gas assets also provides a signal that lower well quality (as measured by initial productivity) will not sustain EIA's optimistic production growth without much higher prices. Shell took a $2billion write down of North American assets last year and announced plans to sell its stake in Eagle Ford Shale because of "disappointing" performance that did not meet the company's profitability targets.

[254] Berman, Pittinger, U.S. Shale Gas: Less Abundance, Higher Cost, *The Oil Drum* (Aug. 5, 2011) available at http://www.theoildrum.com/node/8212.

Tcf of technically recoverable resources (TRR) of natural gas.[255] It then proceeds to assert that at current rates of consumption, the resources are "enough to supply over 90 years of use."[256] In reality, only a small subset of the TRR can be considered "reserves" (about 24 years currently of potential supply) reasonably available for consumption. This distinction is especially important in the context of the proposed rule because EPA policies will drive increased reliance on natural gas for power generation and preclude the deployment of the nation's enormous coal reserves – the most cost effective fuel for base load power generation. A balanced policy would conserve both resources, not simply attempt to elevate one at the expense of the other.

The technically recoverable resources are divided into three categories: (1) speculative; (2) possible; and (3) probable. Only the probable TRR have been tested by drilling and known to be, in fact, technically recoverable. Approximately 30 percent of the TRR is classified as probable,[257] and only about half of the probable TRR is likely to become reserves. In other words, only 15 percent of the entire TRR are likely to be considered as consumption reserves.

Using the AEO 2012 TRR estimate of 2,214 Tcf as cited by EPA, the probable TRR is 664 Tcf – or about 25 years of supply at the consumption rates over the past two years (26.60 Tcf). Converting the probable TRR to reserves equals about 332

[255] RIA at 4-31
[256] *Id*.
[257] The Potential Gas Committee 2012 report classified 723 Tcf of its 2,384 Tcf TRR estimate as probable

Tcf that can be added to the already proved reserve base of 305 Tcf. The combined total of 635 Tcf leaves 24 years of supply at current consumption rates.[258]

Of course, economic viability is a key factor whether resources are eventually converted to reserves and developed. Higher prices would convert more probable resources to reserves. However, these higher energy prices carry consequences for the other sectors consuming natural gas and the economy as a whole. EPA's assessment lacks any analysis of the economic effects of the likely prospects of either higher natural gas prices or a gap in incremental natural gas supply. Less than a quarter century of natural gas reserves is a thin supply margin to risk on a policy that will have profound effects on the economy but not make any material difference in direct global temperature changes.

EPA Fails to Assess the Economic Effects on Other Economic Sectors from Higher Natural Gas Prices or Potential Gaps in the Incremental Natural Gas Supply

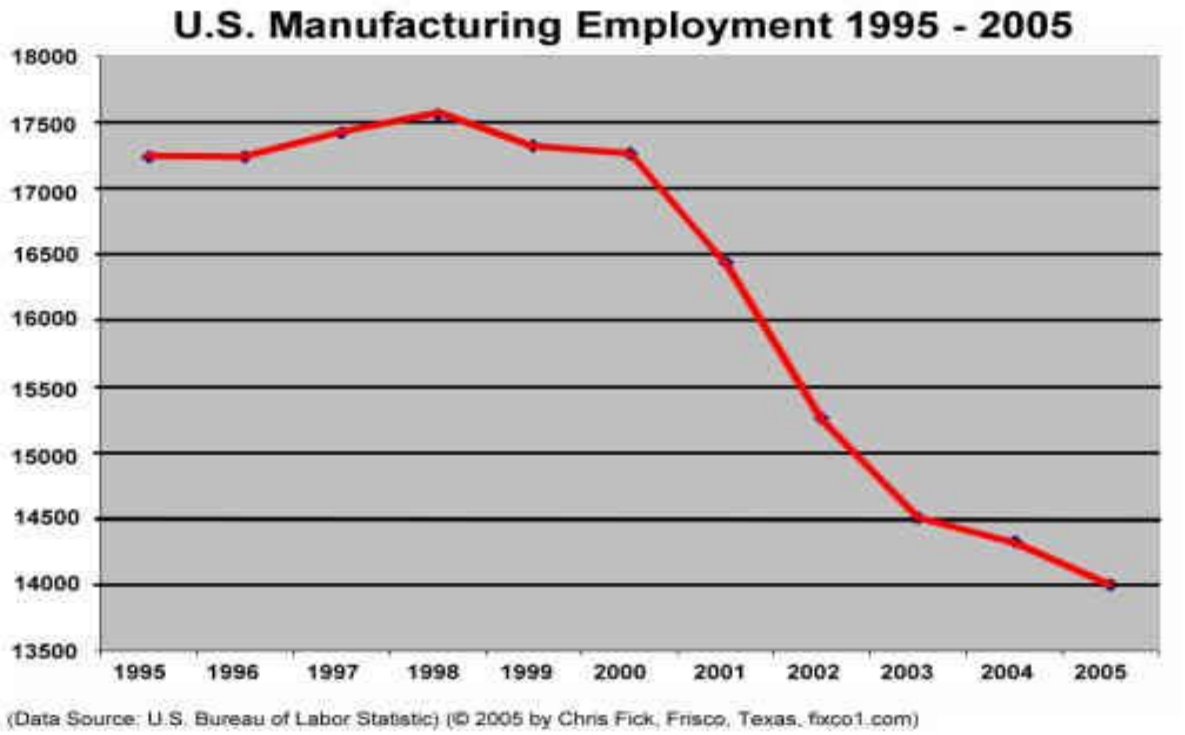
Natural gas serves many masters and many more will soon increase their membership levels in the natural gas consumption club. Every sector has increased consumption and passed their pre-recession levels, with the power and industrial sectors as the largest consumers with the largest consumption increases between 2009-2012 (Power-32%; Industrial-17%). Natural gas use for the transportation fleet continues to increase and many policies are underway to support accelerated growth in the transportation sector. Natural gas exports will begin to coincide with the accelerated retirement of coal EGUs. Four liquefied natural gas export projects

[258] The current consumption rates *do not* reflect the higher power sector consumption due to over 60,000 MW of coal plant retirements

approved so far by DOE have the capacity to export 7.1 bcfd of natural gas by 2018, amounting to more than 10 percent of the current daily supply of 70 bcfd. U.S. exports of natural gas to Mexico are expected to rise by 3.5 bcfd by the end of this year according to DOE – nearly double the current rate.[259]

EPA's analysis does not even touch upon, let alone analyze, any of these market developments and how the proposed rule will affect the economic sectors and residential customer that depend upon natural gas. EPA does not need a crystal ball to evaluate the effects and take them into account in its own policy choices. Recent history provides more than ample experience on the scope and depth of the consequences of placing more "saddle bags" on the natural gas mule. Between 1997 and 2009, the natural gas market experienced five significant price spikes which contributed to the loss of nearly 4 million jobs in manufacturing. They also turned a $19 billion U.S. chemical trade surplus into a deficit from 2001-2007. This occurred when even natural gas demand fell – but prices increased by 160 percent. All of this coincided with an increase in natural gas power plant builds and a 27 percent increase in natural gas consumption in the power sector – more than *three times* the overall growth in natural gas demand by all sectors. There is little question of the direct correlation between manufacturing job losses and higher and more volatile natural gas prices during this period:

[259] EIA, *US natural gas exports to Mexico reach record high in 2012* (March 13, 2013) available at http://www.eia.gov/todayinenergy/detail.cfm?id=10351



Source: U.S. Bureau of Labor Statistics, 2005

Higher natural gas prices produce a vicious one-two punch to consumers with higher natural gas and electricity prices. The power sector presently has several generation options at present, but EPA's proposed NSPS will remove coal from that menu – the most predominant and cost-effective option. Natural gas consumers like manufacturers (raw material), farmers (fertilizer), and homeowners (heating) do not have other options to choose from. As such, they are particularly vulnerable to natural gas price swings. This proposal will only add to the reliability and affordability crisis EPA policies produce by driving the nation to a less diverse electric grid. Nick Akins, CEO of American Electric Power recently informed the Senate Energy Committee that:

> It has become clear that we are having to make a choice in the winter between committing natural gas resources to generating electricity or

> to heating homes. Right now, we cannot do both. Given the number of additional base load generating units that will be retired in the next 14 months, we face a real possibility that we will have to make that choice more often in the future.[260]

Lower income families already spend a higher percentage of their income on energy with electricity becoming a larger component. Almost half of American households will devote an estimated 20 percent of their after-tax income to energy compared with an average of 8 percent for households above $50,000. For those households with pre-tax incomes below 30 percent, the share of their after-tax income devoted to energy is 26 percent.[261] In short, rising energy costs impose a substantial burden on most Americans, especially those households falling below $50,000 in earnings.

While shale gas is potentially a game changer for many sectors of our economy, EPA policies, such as this proposal, present a job-ender and energy tax for everyone. Remarkably, EPA's analysis of the economic effects and energy requirements do not discuss these important considerations let alone factor them into the policy choices available to the agency. This is unacceptable and certainly inadequate under the CAA, other laws and executive orders.

EPA fails to analyze the impacts of its NSPS for Existing Plants

[260] *Keeping the Lights on—Are we doing enough to ensure the reliability and security of the U.S. electric grid?*, Senate Energy and Natural Resources Committee, Statement of Nick Akins, AEP, p. 10 (April 10, 2014) available at http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=366e6685-92f5-4878-a90f-253efa4495e8

[261] ACCCE, Energy Cost Impacts on American Families 2001-2014 (Feb. 2014) available at http://www.americaspower.org/sites/default/files/Trisko_2014_0.pdf

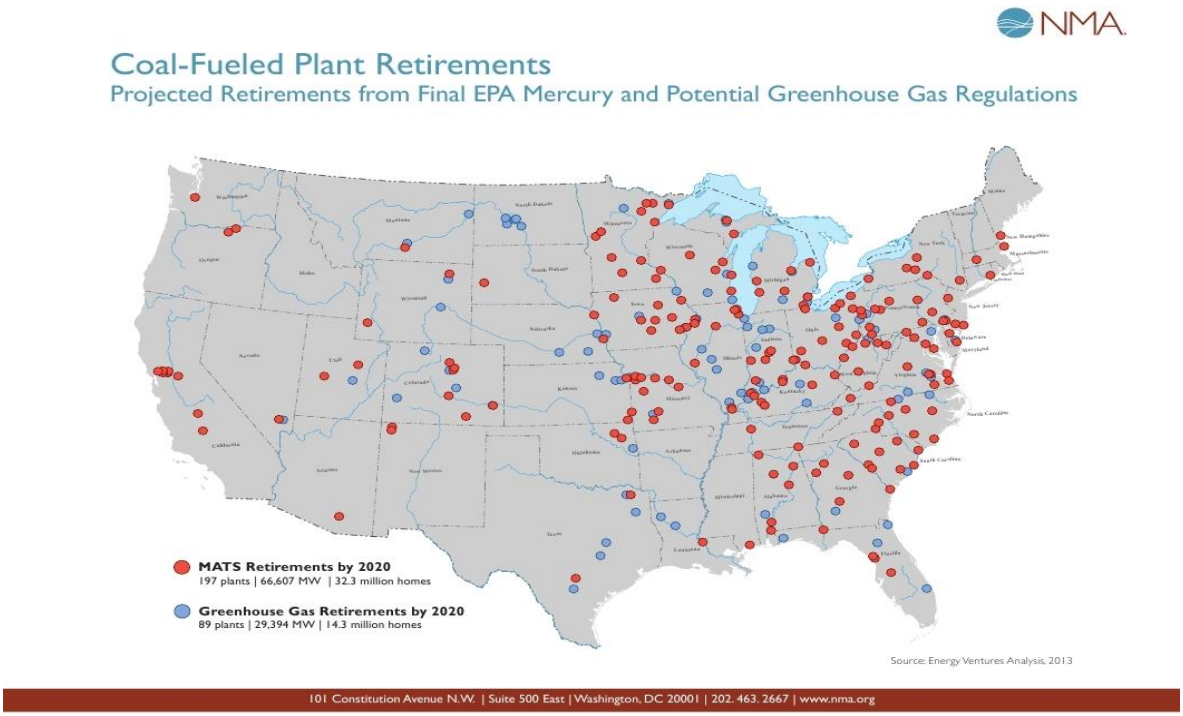
Remarkably, EPA does not assess the potential impacts of this proposal and the proposed rule for existing EGUs referenced in this proposal and the RIA. They are directly connected actions with related effects on the economy and energy requirements. Indeed, EPA expressly states that this proposal is necessary in order to promulgate a NSPS for existing sources. In fact, the soon to be released proposal for existing sources is the only credible reason that can explain this proposal EPA concedes carries no benefits and will result in negligible changes in CO_2 emissions.

EPA cannot excuse its failure to analyze the combined effects of this new source proposal and the inevitable existing source rulemaking by simply saying that it does not have a concrete enough idea on the content of existing source proposal, or that it plans to provide "flexibility" for states. The agency can assess potential impacts by looking at the next tranche of the least efficient EGUs left after most of the accelerated retirements occur in 2015-2016. As noted earlier, identifying the retired, announced for retirement and likely retirements in that time frame are readily available. EPA can then look at the demographic of the remaining coal plants and then assess across various succeeding levels the capacity that would be vulnerable from potentially required CO_2 emission reductions because of the units' age, size and heat rates.[262]

NMA has performed such an analysis through EVA.[263] The results show that the post-MATs retirements will leave approximately 35,000 MW of coal capacity with a heat rate of greater than 11,000 MMBtu/MWh. Most of this would be

[262] Additional sensitivities could be laid over this based upon level of emission reductions that might require some units to run at lower capacity factors for prolonged periods that jeopardize their profitability or efficiency upgrades that might not be economic
[263] See earlier description of the EVA Integrated Electricity Model

affected by modest CO_2 reduction targets through state or regional emission budgets. The result would be an additional 29,394 MW of coal capacity closed for a total of approximately 96,000 MW of capacity shuttered between 2011 and 2020:



Source: Energy Ventures Analysis, 2013

EPA's analysis of the effects of an existing source rule or guidelines does not have to be precise, but it must be done in order to inform the agency of the costs and consequences of the policies under deliberation for its new source rule. The only motivation for not conducting some assessment is to avoid the obvious – new high performing coal technologies (SCPC and IGCC) will be cost competitive with natural gas in a rising energy price market and keeping that option available is the only reasonable policy choice under a range of considerations.

d. New Coal-Fired Power Plants Using Higher Efficiency Technologies are Competitive with Natural Gas Combined Cycle Power

EPA's conclusion that there is no cost incurred with the proposal rests upon a prediction that no coal-fired power plants will be built even in the absence of the proposed rule.[264] EPA's prediction rests upon an analysis finding that between 2020 and 2040 SCPC coal-EGUs cannot compete with NGCC in economically generating power. Several modest adjustments to EPA's input assumptions in the "static, engineering cost analysis" for the Reference Case conditions show conditions under which SCPC and NGCC are equivalent in terms of LCOE. An analysis performed for UARG sets forth the modest changes with justification that erode the cost advantage of NGCC over SCPC found in EPA's assessment.[265]

The first change is removal of the 3 percent so-called "climate uncertainty adder" (CUA). This attempt to quantify the impact of potential project cost increases due to litigation and regulatory delays arbitrarily attempts to add a capital cost penalty to bias the outcome. This charge does not belong in a cost study intended to determine the cost differences between two technologies with CO_2 emissions. The fact that several utilities may use such a charge for internal resource planning does not justify inserting a non-technical concern into a technology-based cost study. Any project – be it nuclear, wind, solar or NGCC – present different risks (political, local opposition or otherwise) into project planning, but developers assign different risks based upon specific conditions and factors.

[264] RIA at 5-1.
[265] J.E. Cichanowicz, A Critiques of the September 2013 Regulatory Impact Analysis Conclusion: Coal Fired Power Not Competitive with Natural Gas Combined Cycle Power (April 29, 2014), attached as Appendix 7. NMA is a member of UARG and we adopt and append the Critique to these comments.

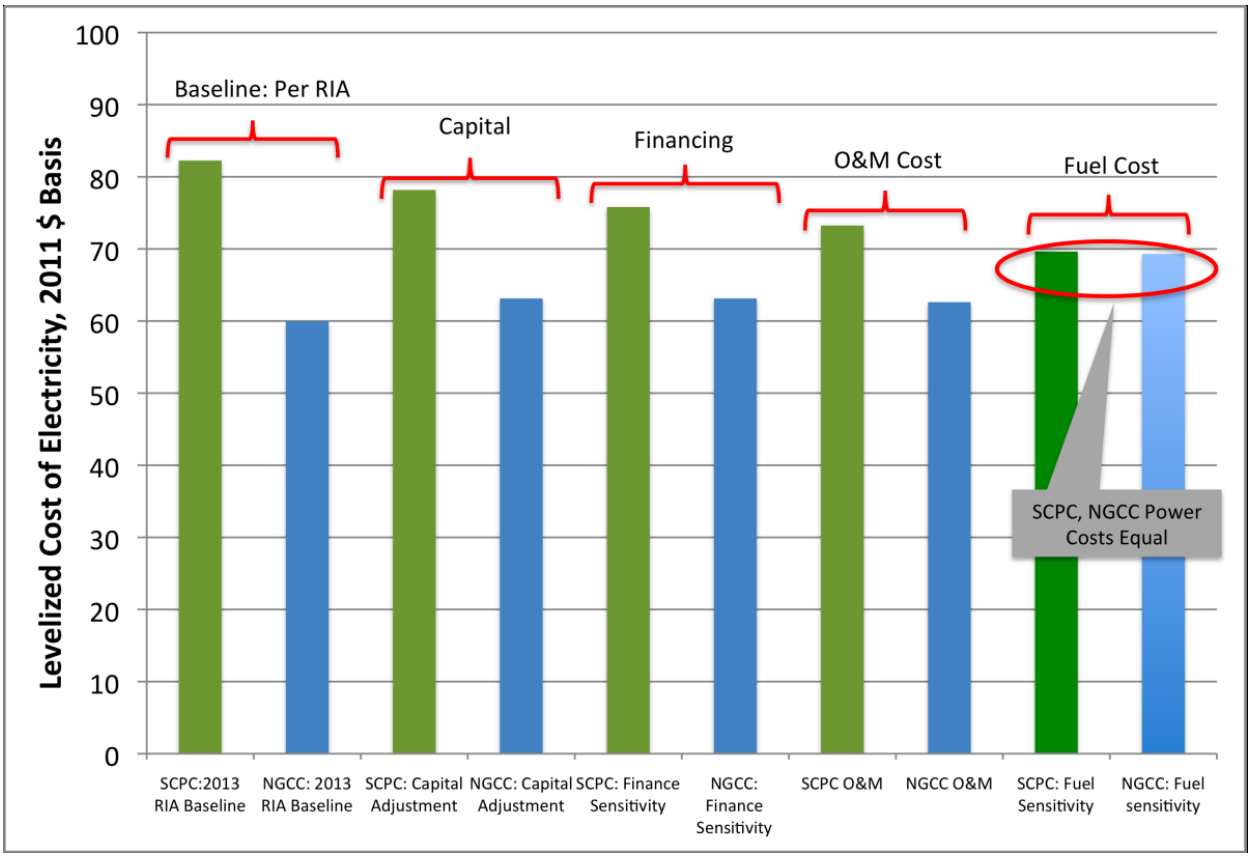
EPA has never explained how all of that can be reduced to a uniform charge in any event. NMA also notes that NGCC power plant projects are experiencing resistance, legal challenges and delays based upon CO_2-based permitting issues. EPA does not address the how these uncertainties are to be quantified and factored into any analysis. A CUA cannot be included in any sound, accurate and unbiased cost study.

To summarize the remaining input changes:

- Capital Cost: Given the uncertainty in capital cost estimates for SCPC and NGCC (a range of +30% and -15% according to EPA), using DOE's report issued in Sept. 2013 (DOE/NETL-2011/1498) decreasing SCPC capital cost by 10% and increasing NGCC capital cost by 15% reduces the NGCC LCOE gap to $15/MWh.
- Eliminate Finance Bias: Both technologies are mature and present the same technical risk. Assuming that finance charges for both SCPC and NGCC are "low risk" as used in the 2012 NETL study (11.6%) decreases the LCOE difference to $13/MWh.
- Operating and Maintenance Cost: Changing the fixed and variable O&M costs in line with Aug. 2012 updated costs studies decreases the LCOE difference to $10/MWh.
- Increasing the Levelized Price of Natural Gas: An increase by $1/MBtu which is in line with trends and not a large variation for a two decade horizon increases the LCOE from NGCC to 69/MWh.

- Decrease Coal Prices: Lowering the delivered coal price from $2.94 to $2.50 for a plant with limited transportation distance decreases SCPC LCOE to $69.60/MWh slightly above the NGCC LCOE of $69/MWh.

The figure below from the UARG analysis shows the successive changes to the capital, financing, O&M and fuel price cost inputs after removing the arbitrary CUA that induces bias in the outcome of a cost study:



These modest adjustments to EPA's input assumptions in the Reference Case conditions show conditions under which SCPC and NGCC are equivalent in terms of LCOE, and these modest changes erode the cost advantage of NGCC over SCPC found in EPA's assessment. EPA's assumptions are unfounded and incorrect, and point to a lack of a robust and economically sound assessment of the ability of

varying generation sources to compete. As such, EPA's analysis underpinning the rule is in error.

X. Potential Impacts on Modified and Existing Sources from EPA's Proposal

This proposed rule is merely step one in the agency's development of regulations to comply with the President's Climate Action Plan to reduce CO_2 emissions from the power sector. The President has given EPA an incredibly aggressive set of regulatory deadlines to meet. The Agency must:

> (i) Issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2014;
>
> (ii) Issue final standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2015; and
>
> (iii) Include in the guidelines addressing existing power plants a requirement that States submit to EPA the implementation plans required under section 111(d) of the Clean Air Act and its implementing regulations by no later than June 30, 2016.[266]

These incredibly tight timelines give the agency very little time to fully consider the impacts of their upcoming proposed regulations, particularly how the currently proposed rule might impact the upcoming set of proposed rules. And without a doubt, all future rules under CAA section 111 will be linked to the legality and

[266] *Memorandum for the Administrator of the Environmental Protection Agency*, 78 Fed. Reg. 39,535 (July 1, 2013) (also available at http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards)

precedential nature of any sector rules proposed under CAA section 111(b), such as the proposed rule. Thus, EPA should proceed cautiously in finalizing the current proposal by pledging that the final rule: (1) will not have any impacts on modified sources that are traditionally subject to section 111(b) authority;(2) cannot set the BACT floor given its impracticability for existing and modified sources, and (3) EPA's technology forcing approach will not be the philosophical underpinning for its upcoming rulemakings.

a. EPA Must Pledge That This Proposed Rule Will Have No Impacts on Modified Sources

While EPA has stated that its proposed rule under CAA section 111(b) only applies to new units,[267] and that the Agency plans on proposing standards for modified units in its upcoming rulemaking, the statutory language states that CAA section 111(b) applies to *both* new and modified units. EPA must emphatically state again that this proposed rule does not apply to modified sources that might be retrofitting to comply with already on-the-books regulations such as MATS, or for future rules, such as EPA's upcoming rules governing transported air pollution under CAA section 110(a)(2)(d). As power plant operators install pollution control equipment such as FGD, SCR, ACI and PM control systems such as baghouses and ESPs, they have the potential to be considered modified units and not existing units if their emissions increase as part of complying with EPA regulations. As such, they could be considered as modified sources under CAA section 111(b). Clarifying the status of these units will avoid stranding the significant investments made by the utility sector to comply with EPA's other significant regulatory actions.

[267] 79 Fed. Reg. 1487

There are significant operational and practical reasons for EPA to refrain from applying this proposal to modified units. Modified sources that are retrofitting pollution control equipment are not intrinsically designed to implement CCS, since CCS design must be factored in at the initial construction of an EGU as the capture system. Further, transportation pipelines and sequestration of the captured CO_2 require significant space and are extremely site specific determinations, and as such must be incorporated at the very beginning of EGU planning. Such design issues were not factored in to the construction of the vast majority of EGUs constructed in the U.S. to date. Additionally, retrofitting carbon capture systems to handle flue gas from older pulverized coal units may not even be feasible – older EGUs were similarly not designed for the installation of post-combustion CO_2 capture systems and are unlikely to have the space to install a full-fledged capture system without fundamentally redesigning and replacing their boiler operations. This could effectively force EGUs to radically alter their operation, making operators effectively redesign themselves as a new source with all of the attendant problems NMA has identified – or retire their unit entirely.

Furthermore, by not requiring modified units to comply with the proposal, EPA properly recognizes there are a limited number of CO_2 sequestration sites domestically where CO_2 can be stored. These sites can be hundreds and hundreds of miles away from an EGU, rendering the transportation and storage components of CCS wildly economically and technically infeasible. For the above reasons, EPA must unequivocally state in the final rule that this rulemaking does not and cannot apply to modified units.

b. The Proposed NSPS Cannot Set the "BACT Floor"

EPA must also clarify that the proposed rule cannot set the "BACT Floor," as previous NSPS rulemakings have done.[268] If the BACT Floor is "reset" to require CCS, EPA's proposal will have significant negative impacts on the ability of the existing fleet to improve its environmental performance or to comply with numerous other existing and future EPA regulations. To date, the BACT permitting process has roundly rejected the installation of CCS. EPA should stay the course now since it is technically and economically infeasible to require facilities undergoing BACT to determine that CCS satisfies BACT requirements.[269] Although BACT and BSER standards are not identical, CCS is so far away from being a commercial reality that CCS is beyond either BACT or BSER. If EPA requires CCS for BACT, that determination would effectively forestall and freeze facilities from installing pollution controls or upgrading their efficiency. EPA states in its proposed rule that:

> This proposal does not have any direct applicability on the determination of Best Available Control Technology (BACT) for existing EGUs that require PSD permits to authorize a major modification of the EGU.[270]

NMA requests that EPA unequivocally state in the final rule that the standard has no applicability, direct or indirect on these existing EGUs or the BACT permitting process whatsoever in order to avoid confusion and the potential negative impacts on the BACT process in the future.

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[268] BACT Guidance at 10 ("The CAA specifies that BACT cannot be less stringent than any applicable standard of performance under the New Source Performance Standards (NSPS)"). *See also* 40 CFR 52.21(b)(12)
[269] For a further discussion of the lack of CCS as BACT, please see the comments of EEI on both this re-proposal and the original 2012 NSPS proposal
[270] 79 Fed. Reg. 1487

c. EPA's Precedent in This Rulemaking is Concerning Since it is Planning on Proposing 111(d) Guidelines for the Existing Fleet as Part of the President's Climate Action Plan

NMA's concerns about upcoming EPA rulemakings are not unfounded given the agency's stance in this proposed rule. Not only has the agency proposed an arbitrary and capricious standard that has not been adequately demonstrated at a single commercially operating facility, EPA has refused to conduct a genuine analysis of applying CCS to natural gas fired units. EPA's arbitrary treatment of new units likely portends future rash actions for modified and existing units. As various statements from the administration have revealed, the current action is seen as obstacle that must be overcome to get to the "big ticket item" in the President's Climate Action Plan: namely the existing power plant fleet and coal plants in particular.

In addition, as EPA moves forward with the rules for existing units, the agency needs to update its 2009 endangerment finding in order to better capture new developments and better understand the nature of climate science as it evolves. EPA relies heavily on its 2009 endangerment finding in its rationale for pursuing standards for new power plants in the proposed rule despite the filing of several petitions for reconsideration of that finding. EPA denied the petitions alleging that the petitioners failed to provide substantial support for revisions of the endangerment finding and therefore their objections were not of ''central relevance'' to the finding.[271] That EPA's endangerment finding has been upheld by the D.C. Circuit does not mean the agency should not revisit the finding moving forward. The 2009 finding relied heavily on work done prior to 2006 – which, given

[271] 79 Fed. Reg. 1438

the Climate Action Plan's timeline of 2016 for action on the existing EGU fleet, would make the basis for EPA's actions almost a decade old at the time that states would be required to submit their plans for any upcoming CAA section 111(d) rulemaking. That ten year gap represents both a wealth of new data on climate science that could change both some of the fundamental assumptions EPA relied upon as well as allow EPA to better understand the impacts of climate change as it moves forward in the regulatory process. While the existing EGU fleet represents a large portion of domestic carbon emissions, that amount has been declining due to the impacts of EPA's previous regulatory actions and other significant market forces. It is merely prudent rulemaking for EPA to begin again the process of updates to its previous work done in the endangerment finding in order to be on the soundest footing possible moving forward with implementing the President's Climate Action Plan. NMA requests that EPA initiate this update immediately in order to make informed judgments relying on the most up to date science and facts.

Such an approach is wholly consistent with the CAA. The CAA is a technology based statute that requires EPA to continue to update its standards for emissions sources based on what is technologically achievable in today's real terms, as defined by commercially operating realities. The agency has departed from this common sense approach to deriving a regulatory scheme here, and should it continue down this path, its upcoming rulemakings will necessarily suffer the same fatal flaws – flaws that will lead to significant negative consequences for environmental protection, industrial and economic growth, and for consumers both small and large.

XI. NMA Supports EPA's Exemption for Units Designed to Sell Less Than 1/3rd of Their Output to the Electric Grid

EPA has proposed an exemption from CO_2 standards for units designed to sell less than 1/3rd of their output to the electrical grid, defined as less than 219,000 MWh of net sales (as opposed to a limit of 25MW of net electrical output), which EPA notes is consistent with the Acid Rain Program definition and functionally equivalent to its prior definitions.[272] NMA supports EPA's exemption for this classification of units, and agrees that the classification criteria included by EPA at 219,000 MWh of net sales is consistent with prior definitions. EPA has long distinguished between cogeneration/CHP units, such as those that exist at many mine sites which produce minerals and metals, and utility operations that fundamentally generate power, and the agency should continue to do so as it develops regulations addressing CO_2 emissions. These units provide steam power for industrial processes and can sell excess capacity to the electrical grid in small amounts, resulting in well understood environmental benefits and enhanced grid reliability – especially in grid constrained areas where many mine sites are located. As such, NMA supports EPA's exemption and definitions, and urges EPA to retain the Acid Rain Program definition as opposed to other efficiency definitions such as standards derived from the PURPA as was once proposed in the CATR in 2010.

a. EPA Has Long Distinguished Between Industrial Cogeneration Units and Utility Units When Applying Regulations Under the CAA

EPA has long distinguished between industrial cogeneration units and utility units when applying regulations under the CAA. Many mining facilities that

[272] 79 Fed. Reg. 1446

produce minerals and metals have onsite cogeneration/CHP units that have qualified as cogeneration units under all previous CAA programs, including those targeting new sources,[273] hazardous air pollutants,[274] and acid rain reductions.[275] EPA has consistently drawn a distinction between "electric utility steam generating units and industrial boilers because there are significant differences between the economic structure of utilities and the industrial sector."[276] Whereas a utility may pass on the costs of emissions control technology requirements to its retail electricity customers, industrial cogeneration facilities that sell wholesale products in a globally-competitive market do not have that option. The amount of electricity generated for sale by these types of industrial cogeneration units is relatively small and often produced inconsistently because the primary driver for operation is the industrial process, and electricity is a secondary product generated from excess steam to improve the energy efficiency of the system. These distinctions are important, and EPA should continue to recognize them as it moves forward with its regulatory path for CO_2.

b. Adding Cogeneration to an Industrial Steam System Results in Well Understood Environmental Benefits

EPA has recognized the environmental benefits that arise from adding cogeneration to an industrial steam system. Generating electricity from excess steam can significantly improve energy efficiency and provide a corresponding reduction in emissions from the reduced demand for electricity from off-site sources. EPA appropriately seeks ways to encourage the development and

[273] *See e.g.,* 40 CFR 60.41a
[274] *See* 40 CFR 63.41
[275] *See* 40 CFR 72.2
[276] *See e.g.,* 44 Fed. Reg. 33580, 33589 (June 11, 1979)

operation of cogeneration systems and to avoid disincentives in this proposed rulemaking. In the proposed NSPS, like in previous regulatory regimes as in the Acid Rain Program, EPA appropriately exempts most industrial cogeneration units. This exemption removes a disincentive to cogeneration that may otherwise exist if an industrial boiler operator had to comply with an entirely new and burdensome regulatory program just because it generates more electricity than it may need on a given day and sells that electricity to the grid.

CHP units are used because they can reduce the cost of power and steam while providing a reliable source of energy. Because it is a distributed energy source, it also supports stability of the electrical grid. By not purchasing electricity from the grid, the use of CHP reduces U.S. energy consumption, criteria pollutants, and overall GHG emissions. These well understood benefits are embedded in EPA's proposal, and EPA should continue to acknowledge the vital and unique role CHP power sources play in providing environmental benefit, grid reliability, and enhancing the competitiveness of America's minerals and metals producers in the global marketplace.

c. EPA Should Retain Efficiency Standards for Cogeneration Units Based Upon the Acid Rain Program Exemptions, not the PURPA Definition

As EPA finalizes this rule, it should not deviate from the Acid Rain Program definition. EPA should learn from its previous experiences with CAIR and CATR, to ensure legitimate cogeneration units are eligible for the cogeneration example. In drafting CAIR, EPA added a requirement not found in the Acid Rain Program that requires cogeneration units to meet specified efficiency standards to qualify for the cogeneration exemption. As EPA explained:

> The purpose of this efficiency standard in the cogeneration unit definition is to prevent a potential loophole where a unit might send only a nominal or insignificant amount of thermal energy to a process and not achieve significant efficiency gains through cogeneration, but still qualify as a cogeneration unit and potentially qualify for the cogeneration unit exemption.[277]

This same efficiency standard was also incorporated into the CATR to ensure that the cogeneration exemption only excludes legitimate cogeneration systems from the CATR.

Unfortunately, the efficiency standards proposed in the CATR excluded legitimate cogeneration units from eligibility for the cogeneration exemption. The efficiency standards were derived from PURPA and were intended to apply to newer units where "installation began on or after March 13, 1980."[278] Many mine site power systems were constructed prior to 1980 in order to provide steam for minerals and metals processing and other industrial activities, and are not units that would be covered by these PURPA efficiency standards. In fact, it is unlikely that any coal-fired cogeneration system installed in prior to 1980 would be capable of meeting the efficiency standards included in PURPA for post-1980 units.

EPA did not appear to anticipate that its adoption of the PURPA definition would result in cogeneration units becoming subject to the rulemaking. When developing the CAIR, EPA concluded that all cogeneration units would meet the PURPA efficiency standard:

[277] Final Rule Revising the Definition of Cogeneration, 72 Fed. Reg. 59190, 59194 (October 19, 2007)
[278] 18 CFR 292.205(a)(2)(i)

> The EPA analyzed a range of solid fuel-fired cogeneration units and calculated their efficiencies to see if they would meet the proposed minimum efficiency standard. All of the units selected satisfied the proposed efficiency standard. As a result, EPA believes that most solid fuel-fired cogeneration units will meet the proposed efficiency standard.[279]

EPA unfortunately failed to consider the impact on the older cogeneration systems which have historic efficiency rates that are well below the efficiency standard developed by PURPA for post-1980 cogeneration systems. The historic cogeneration systems that had the foresight in the 1950s and 1960s to add electric generators to industrial steam systems appeared to have been inadvertently caught in an overbroad attempt to close a loophole. These are not units that use a nominal or insignificant amount of thermal energy to qualify for the cogeneration exemption, but are legitimate cogeneration systems by any measure. EPA should exercise its discretion to allow these legitimate historic cogeneration units to qualify for the cogeneration unit exemption without meeting the PURPA efficiency criteria. As such, NMA supports EPA's exemption and definitions in this proposed rulemaking, and urges EPA to continue to use the Acid Rain Program definition for efficiency when considering cogeneration/CHP units in this and future rulemakings regulating CO_2 through the CAA from the electric utility and other industrial sectors, including minerals and metals mining and processing.

d. NMA Supports the Use of Net Output Based Standards for All Covered Sources

[279] 70 Fed. Reg. 25162, 25277 (May 12, 2005)

NMA also supports the use of net output-based approaches for all covered sources, as the utilization of those approaches more accurately captures advances in boiler efficiencies. In the proposed rule, EPA requests input on including options for use of net output-based standards in the final rule, stating that:

> We are also considering and requesting comment on using net-output based standards either as a compliance alternative for, or in lieu of, gross-output based standards, including whether we should have a different approach for different subcategories.[280]

EPA appears to only focus on applicability to units with carbon capture and storage controls, despite the general recognition that net output-based approaches account for advances in process efficiencies on a much broader scale.[281] Net output-based approaches are particularly appropriate to advance emission reductions from base load sources at either units with or without CCS technology, and as such should be adopted as an option for those sources at a minimum. As such, NMA supports the inclusion of net-output based standard as an option to provide for more operational flexibility for all covered units.

CONCLUSION

In closing, EPA's proposal at issue is fundamentally flawed technically, legally, and as policy. NMA urges EPA to seriously consider these comments and correct the deficiencies when it promulgates the final rule. Failure to do so dooms EPA's rule not only in the legal sense, but also its ability to achieve real emissions reductions and advance technology.

[280] 79 Fed. Reg. 1447
[281] *Id.* at 1448

As noted extensively above, the proposal's fatal flaw is EPA's failure to comply with the strictures of the CAA by determining that partial capture CCS is BSER for new coal-fired units. CAA section 111(b) provides EPA certain discretion in establishing standards of performance for new sources. Importantly, however, Congress constrained EPA's standard-making authority in two significant ways by requiring every NSPS to be "*achievable*" through a system of control that "*has been adequately demonstrated*." In the proposed standard for new coal plants, EPA has failed entirely to show CCS technology is either achievable or adequately demonstrated. For that reason, and for all the other well documented reasons above, NMA strongly urges the Agency to withdraw it and to pursue a more rational path forward on regulation of CO_2 from the power sector. NMA appreciates the opportunity to express our views with the agency. Should you have any questions, please feel free to contact Alex Bond at (202) 463-2600 or via e-mail at abond@nma.org.

REVIEW AND SUMMARY OF TECHNICAL BASIS USED BY EPA IN SETTING STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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BACKGROUND AND INTRODUCTION

On January 8, 2014, the Environmental Protection Agency (EPA or Agency) published in the Federal Register a proposed New Source Performance Standard (NSPS) for carbon dioxide (CO_2) emissions from new fossil-fuel-fired electric utility generating units. Under the proposal, new coal-fueled electric steam generating units (boilers) and integrated gasification combined cycle (IGCC) units would be required to meet a performance standard of 1,100 lbs. CO_2 per megawatt-hour (MWh). EPA based the 1,100 lb. standard on the use of carbon capture and storage (CCS) technology. According to the Agency, in order to meet this standard, a new coal-fueled boiler or IGCC unit would have to capture approximately 30-50% percent of the CO_2 it would otherwise emit and then transport that CO_2 to an underground storage site where the CO_2 would be permanently sequestered.[1]

EPA proposed the standard under Section 111 of the Clean Air Act (CAA). Under Section 111(a), an EPA NSPS must "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost achieving such reduction and any nonair quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated." This standard historically has been known as Best Demonstrated Technology (BDT); more recently, EPA has referred to this standard as Best System of Emission Reduction (BSER).

Section 111 was added by the 1970 Amendments to the CAA, and EPA first began adopting NSPS rules in 1971. Thus, there is more than 40 years of Agency precedent in developing and issuing standards of performance for new stationary sources. By our count, [2] EPA has adopted NSPS for 75 individual source categories.

EPA first adopted NSPS for coal-fueled utility boilers in 1971 as a part of its first set of NSPS.[3] These standards covered sulfur dioxide (SO_2), nitrogen oxide (NO_X) and particulate matter (PM) emissions. EPA has revised these standards from time to time over the years, most recently in 2011.[4] Thus, in addition to there being a great deal of precedent for EPA's adoption of NSPS requirements generally; there is a great deal of precedent for EPA adoption of performance standards for coal-fueled utility boilers specifically.

EPA's proposed NSPS requirements for CO_2 emissions from coal-fueled utility boilers and IGCC units is not based on the demonstrated performance of any such boiler or unit that is in operation today. There is, in fact, no coal-fired utility boiler or IGCC unit in operation anywhere

[1] 79 Fed. Reg. 1,430, 1,433-1,436 (Jan. 8, 2014).
[2] Our count of 75 does not include EPA revisions to an NSPS. For example, Petroleum Refineries is only one source category, although there is a Subpart J NSPS (for units that commenced construction after June 11, 1973) and a Subpart Ja NSPS (for units that commenced construction after May 14, 2007).
[3] 36 Fed. Reg. 15,704 (Aug. 17, 1971).
[4] 76 Fed. Reg. 24,976 (May 3, 2011).

in the world that use full or partial CCS and, as a result, emits only 1,100 pounds of CO_2 per MWh. Because of this, in proposing to set an 1,100 pound per MWh standard, EPA has projected the CO_2 emissions performance that the Agency claims a coal-fueled utility boiler will achieve if equipped with a CCS system that captures 30-50 percent of the facility's CO_2 emissions. EPA based its projection on two coal-fueled utility facilities that are under construction, two facilities that remain in the planning stage, pilot projects, and literature.[5]

The National Mining Association (NMA) asked RMB Consulting & Research, Inc. (RMB) to review EPA's history of adopting NSPS and to summarize the technical basis and/or rationale that EPA cited in developing each standard. Based on this review, NMA asked RMB to examine whether precedent exists in prior EPA NSPS rulemakings for the agency to set performance standards that are not based on the demonstrated performance of facilities within the regulated category that are actually in operation at commercial scale.

SUMMARY AND CONCLUSIONS

RMB reviewed EPA NSPS rulemakings for 68 source categories. RMB did not review approximately 10 NSPS rulemaking, which focused on volatile organic carbon (VOC) emissions and did not appear particularly relevant to our study. For each source category we reviewed, RMB summarized the specific information that EPA relied on in setting the applicable NSPS. We also provide this information in tabular form in Table 1 at the back of the report.

Our conclusions are as follows:

- EPA has never before adopted a performance standard where the standard had not been achieved by multiple commercial-scale facilities in the source category to which the standard applies. EPA's approach to its proposed CO_2 NSPS for coal-fueled utility boilers and IGCC units thus is unprecedented.

- The large majority of the categories for which EPA has set NSPS involve facilities that have stacks through which the facilities' emissions pass or where it was otherwise feasible to do emissions tests. In most of these cases, EPA based its NSPS on monitored data obtained from doing stack tests at multiple units operating at commercial scale. For certain pollutants in these source categories, EPA used chemical analyses of the input fuel to determine emission standards based on operating experience at multiple existing commercial-scale units. In some cases, EPA set opacity standards based on actual observations of visible emissions. Thus, in all of these cases, EPA based its determination of "demonstrated" technology on actual data from units in operation within the source category. By contrast, in its proposed NSPS for CO_2 emissions from coal-fueled utility boilers and IGCC units, EPA has not based the proposed standard on actual

[5] 79 Fed. Reg. at 1,467-1,485.

monitored data from units at full commercial operation because there is no such data.

- The preceding conclusion holds true for the NSPS that EPA has adopted for non-CO_2 emissions from coal-fueled utility boilers and IGCC units.

    - For instance, in EPA's most recent revision to the standards in this category, the Agency established standards for SO_2 and NO_X emissions based on hourly pollutant emission data as reported by utilities to EPA's Clean Air Markets Division. To establish the standards for PM and carbon monoxide (CO), EPA required approximately 200 electric generating units to test for PM and CO. EPA also relied on historical emissions information that utilities submitted for several hundred units.[6]

    - When EPA first required the use of selective catalytic reduction (SCR) technology to reduce NO_X emissions, EPA relied on data from 137 coal-fueled units in Germany, 40 coal- fueled units in Japan, 29 coal-fired units in Italy, and 10 other coal- fueled units in other European countries, all of which were using SCR in full commercial operation. In addition, full-scale SCR was used at seven coal- fueled utility boilers in the U.S. at the time of proposal.[7]

    - For flue gas desulfurization systems, EPA required wet scrubbers in its 1979 NSPS rulemaking on the ground that wet scrubbers had been in commercial use since the late 1960's. EPA, however, rejected the use of dry scrubbers on the ground that there were no dry scrubbers in full commercial operation at utility plants and the only information available was derived from pilot scale projects.[8]

- In some instances, all of which involved emissions of volatile organic compounds, which typically do not vent through a stack or for which there is no feasible method of monitoring actual emissions, EPA did not rely on actual emissions tests. Instead, EPA relied on the actual operating experience in reducing VOC emissions from sources within these categories based on various types of control technologies or systems or on actual testing of materials used to reduce emissions.[9] Again, this contrasts with EPA's current proposal, where there is no actual

[6] 76 Fed. Reg. 24,976 (May 3, 2011).
[7] 63 Fed. Reg. 49442 (Sept. 16, 1998).
[8] 44 Fed. Reg. 33,594 (1979). See *Sierra Club v. Costle*, 657 F.2d 298, 341 n.157 (D.C. Cir. 1981) (it would be premature to conclude that dry scrubbing is adequately demonstrated)
[9] *See, e.g.*, EPA NSPS for Automotive and Light-Duty Truck Surface Coating Operations, 44 Fed. Reg. 54,970 (Oct. 5, 1979);EPA NSPS for VOC emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations, 48 Fed. Reg. 57,538 (Dec. 30, 1983); EPA NSPS for Rubber Tire Manufacturing Industry, 48 Fe.d Reg. 2,676 (Jan. 20, 1983); EPA NSPS for VOC emissions from Petroleum Refinery Wastewater Systems, 52 Fed. Reg. 16,334 (May 4, 1987); NSPS for VOC emissions from SOCMI Reactor Processes, 55 Fed. Reg. 26,953 (Jun. 29, 1990).

operating experience using CCS at commercial scale for coal-fueled utility boilers or IGCC units.

- In some cases, the lack of actual data from facilities in commercial operation has caused EPA not to adopt numerical standards.[10]

In sum, in contrast to EPA's current proposal, the Agency has never before promulgated an NSPS based on technology that was not, at the time the Agency adopted the standard, in use at facilities in full-scale operation.

RMB STATEMENT OF QUALIFICATIONS

RMB was incorporated in the State of North Carolina in June 1994. The three RMB principals have more than 90 years of combined experience in air pollution control and air pollution consulting. RMB specializes in providing consulting services to industrial clients and associated organizations. Specific service areas include: regulatory analysis; evaluation of air pollution control technology; developing and managing continuous emissions monitoring programs; designing and implementing source testing programs; and litigation support. RMB has reviewed and submitted technical comments on every rule proposed by EPA in the last 20 years that affect electric generating units, either from imposing new emission limits or emission monitoring requirements.

Present clients include many individual electric utility companies, several major chemical and petroleum industry clients, pulp and paper clients, several law firms, the National Mining Association (NMA), the Electric Power Research Institute (EPRI), and the Utility Air Regulatory Group (UARG). A more detailed statement of our qualifications is provided in Appendix A.

SUMMARY OF INDIVIDUAL NSPS TECHNICAL BASIS AND JUSTICATIONS

Subpart D: Standards of Performance for Fossil-Fuel-Fired Steam Generators.[11]

In 1971, Subpart D was among the five standards of performance for new stationary sources proposed by EPA. EPA determined BDT for particulate matter (PM) to be a state-of-the-art electrostatic precipitator (ESP). To support the proposed PM emission limit, EPA collected Method 5 PM data from several coal-fired utility boilers that had installed new ESPs. EPA used visual emission observations from those units for the proposed 20 percent opacity limit. EPA primarily relied on extensive coal sampling and analysis data to support the proposed SO_2 emission limit. In fact, EPA asserted that at least 25 percent of the known U.S. coal reserve would be "compliance coal, and utility companies could comply with the proposed 1.2 lb/mmBtu emission limit by burning low sulfur compliance coal. The proposed NO_X emission limit was based on the analysis of a series of Method 7 stack tests.

[10] *See, e.g.*, EPA NSPS for VOC emissions from Crude Oil and Natural Gas Production, Transmission, and Distribution, 76 Fed. Reg. 52,738 (Aug. 23, 2011);
[11] 36 Fed. Reg., 15,704 (August 17, 1971).

Subpart Da: Standards of Performance for Electric Utility Steam Generating Units.[12]

In 2011, EPA proposed to amend the emission limits for PM, SO_2 and NO_X for electric utility steam generating units. In establishing the output-based SO_2 and NO_X emission limits, EPA used hourly pollutant emission data as reported to EPA's Clean Air Markets Division (CAMD). In theory, EPA could have examined data from the 1,100 or so operating electric utility units because all of these units are required to submit quarterly electronic data reports (EDRs) to CAMD. According to EPA, the development of a robust data set on which to base the amendments, the Agency analyzed emissions data from both older plants that have been retrofitted with controls as well as recently operational units.

PM and CO data are not reported to CAMD. Instead, EPA relied on test data collected pursuant to a huge information collection request (ICR). EPA required approximately 200 electric generating units to test for PM and CO. Moreover, under Part II of the ICR, several hundred electric generating units submitted historical emission test data.

Subpart Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and

Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.[13]

In 2005, EPA proposed to maintain the existing Subpart Db and Dc NSPS emission limits for SO_2 and NO_X. However, EPA proposed to lower the Subpart Db and Dc PM emission limit to 0.03 lb/10^6 Btu for units that burn coal, oil, wood or a mixture of those fuels. EPA based the PM emission limit on the use of fabric filters or high efficiency electrostatic precipitators (ESP). To determine the appropriate limit, EPA reviewed boiler permit limits and emission information gathered for (existing) industrial, commercial and institutional boilers. Using the available emission information, EPA concluded that a PM emission limit of 0.03 lb/10^6 Btu was achievable by all industrial, commercial, and institutional boilers considering the wide variety of fuels fired and the range of operating conditions under which those boilers would operate.
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Subpart Eb: Standards of Performance for Municipal Waste Combustors.[14]

Among other things, the 1990 amendments to the CAA added a new Section 129. Section 129 applies to a range of solid waste incinerators including municipal waste combustor (MWC) units, medical waste incinerators and industrial waste incinerators. Section 129 requires EPA to use the maximum achievable control technology approach in developing NSPS for incineration units specified in this section of the CAA. Pursuant to § 129 requirements, EPA reviewed its existing NSPS for MWC units (Subpart Ea) and concluded that it was not fully consistent with § 129 requirements. Therefore, on September 20, 1994, EPA proposed standards of performance for new, MWC units as Subpart Eb to supersede Subpart Ea.

[12] 76 Fed. Reg., 24,976 (May 3, 2011).
[13] 70 Fed. Reg. 9,706 (February 28, 2005).
[14] 59 Fed. Reg., 48,198 (September 20, 1994).

In developing its proposed standards of performance for new MWC units, EPA devoted considerable effort to selection and characterizing maximum achievable control technology (MACT). For example the Agency states, "based on test data from MWC's equipped with SD/FF and SNCR (large plants only) control systems, the EPA established the MACT floor as the emission control level for each pollutant achieved in practice by the best controlled MWC unit." A subsequent decision by the D.C. Circuit Court,[15] typically referred to as "Brick MACT," would result in EPA placing less reliance on identifying/specifying technology and more reliance on analyzing emission test data to set MACT floors.

In proposing Subpart Eb, EPA primarily relied on a database that had been created for establishing the 1989 NSPS (Subpart Ea). However, for a few pollutants in the 1994 proposal, EPA was able to obtain more recent test data to supplement the Agency's 1989 database. It is interesting to note that EPA requested comments on whether the Agency should consider test data from only the most recently built MWC units or should consideration be given to all operational MWC units independent of age?

Subpart Ec: Standards of Performance for New Stationary Sources: Hospital/Medical Infectious Waste Incinerators.[16]

EPA initially proposed emission standards for new medical waste incinerators on February 27, 1995. EPA granted reconsideration to consider supplemental material and proposed a reconsideration response on June 20 1996. EPA issued its initial NSPS for hospital/medical infectious waste incinerators (HMIWI) on September 15, 1997. Litigation began immediately, and the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) remanded the HMIWI rule to EPA for further explanation. However, the HMIWI regulations were not vacated by the D.C. Circuit and were fully implemented by September 2002. EPA published its proposal in response to the D.C. Circuit's remand on February 6, 2007. Following the D.C. Circuit's decisions on other cases and receipt of public comments, EPA re-proposed its response to the remand and published a proposed rule on December 1, 2008. Despite the tumultuous history of the HMIWI regulations, lack of emission data was not the problem. There exists a contractor memorandum showing test results from at least 20 different HMIWI units located throughout the U.S.

Subpart F: Standards of Performance for Portland Cement Plants.[17]

In 2008, EPA proposed to amend the PM emission limit and to establish emission limits for SO_2 and NO_X for newly constructed kilns. In assessing the level of performance constituting best demonstrated technology (BDT), EPA reviewed data on PM limits in eight recently issued permits for new cement kilns. In order to determine if permitted PM limits were representative of actual performance, EPA reviewed two datasets based on EPA Method 5 tests. EPA also reviewed 37 emission tests for PM from Florida kilns equipped with fabric filters where the bag

[15] *Sierra Club v. EPA*, 479 F.3d 875 (D.C. Cir. 2007).
[16] 73 Fed. Reg., 72,962 (December 1, 2008).
[17] 73 Fed. Reg., 34,072 (June 16, 2008).

material was unknown. However, EPA reviewed 19 emission tests conducted on four kilns where the Agency was able to establish that the plants used fabric filters with membrane bags.

For NO_X, EPA examined three options for BDT: (1) low NO_X burners with staged combustion, (2) selective non-catalytic reduction (SNCR) systems, and (3) selective catalytic reduction (SCR) systems. EPA's BACT/RACT/LAER Clearinghouse Database contained determination for 30 new, modified or reconstructed kilns. For its database, EPA determined that the exclusive add-on control technology for NO_X in the U.S. is SNCR. SCR is another NO_X control technology widely used in the electric utility industry. While SCR is demonstrated in Europe, SCR has never been used on any cement kiln in the U.S. In proposing a NO_X emission limit, EPA reviewed recently issued permits, recent BACT determinations and recent emissions data for preheater/precalciner kilns to establish potential NO_X control limits. It is interesting to note that EPA did not propose SCR as BDT because it is not demonstrated in the U.S. on cement kilns, there are potential technical operating difficulties with SCR in this industry and the somewhat high cost effectiveness combined with the general uncertainty in making the cost estimates.

EPA examined four BDT options for SO_2 control: (1) no additional control, (2) alkaline wet scrubber, (3) lime injection, and (4) wet scrubber. EPA proposed a moderate uncontrolled SO_2 emission rate of 1.3 lb/ton of clinker based on the average of 18 data points for tested NSPS facilities. This rate is based on long-term performance, typically consisting of 30 days of data from continuous emission monitoring system (CEMS). According to EPA, the proposed SO_2 emission limits can be achieved when using low sulfur raw materials (e.g., limestone) or with the addition of an alkaline scrubber when using raw materials with moderate or high sulfur levels.

Subpart Ga: Standards of Performance for Nitric Acid Plants.[18]

According to the Section IV "*Rationale for the Proposed Standards*" contained in the preamble to the proposed rule dated Friday, October 14, 2011, emissions test data were obtained from a number of sources including a section 114 Information Collection Request (ICR), trade associations, and the EPA Region 5. Nine relative accuracy test audit (RATA) reports for 5 nitric acid production units controlled with Selective Catalytic Reduction (SCR), 6 RATA reports for 6 nitric acid production units controlled with Nonselective Catalytic Reduction (NSCR), and 1 RATA report for 1 nitric acid production unit controlled with Hydrogen Peroxide Injection (HPI). These emissions tests were short term and are presented in the memorandum *Summary of Test Data Received from Section 114 ICR,* dated August 25, 2010 (updated December 17, 2010).

In response to the section 114 request, nitric acid plants submitted NO_x Continuous Emission Monitoring Systems (CEMS) data. These included 3 facilities using SCR and 2 facilities using NSCR. These data included long-term analysis to account for unit start-up and shut-down periods. In addition, emissions based on periods ranging from 15 minute averages to and 30 day rolling averages were analyzed. All of the data collected and analyzed were used in establishing the applicable emissions limit(s).

Subpart I: Standards of Performance for Hot Mix Asphalt Facilities;

[18] 76 Fed. Reg., 63,878 (October 14, 2011).

Subpart J: Standards of Performance for Petroleum Refineries;

Subpart K: Standards of Performance for Storage Vessels for Petroleum Liquids;

Subpart L: Standards of Performance for Secondary Lead Smelters;

Subpart M: Standards of Performance for Secondary Brass and Bronze Ingot Production Plants;

Subpart N: Standards of Performance for Iron and Steel Plants; and

Subpart O: Standards of Performance for Sewage Treatment Plants.[19]

On June 11, 1973, EPA proposed seven Standards of Performance for new sources in the Federal Register: Subparts I, J, K, L, M, N and O. According to the preamble of EPA's proposal:

> The bases for the proposed standards include the results of source tests conducted by the Environmental Protection Agency and local agencies, data derived from available technical literature, information gathered during visits to pollution control agencies and plants in the United States and abroad, and comments and suggestions solicited from experts. In each case, the proposed standard 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 has determined has been adequately demonstrated. Background information which presents the factors considered in arriving at the proposed standards, including costs and summaries of test data, is available free of charge from the Emission Standards and Engineering Division, Environmental Protection Agency.

Moreover, EPA acknowledges that in developed of the proposed NSPS for asphalt concrete plants, the Agency received considerable comment from industry indicating that the allowable emission rate could not be achieved routinely. Test data reviewed and analyzed by EPA and other supporting arguments led to the EPA Administrator's judgment that the allowable emission levels could be achieved at a reasonable cost.

Subpart Ja: Standards of Performance for Petroleum Refineries.[20]

On May 14, 2007, EPA proposed to amend the standards of performance for petroleum refineries. Four sources of information were considered in reviewing the appropriateness of the current NSPS requirements for new sources: (1) Source test data from recently installed control systems; (2) applicable State and local regulations; (3) control vendor emission control guarantees; and (4) consent decrees. (A significant number of refineries, representing about 77 percent of the national refining capacity, are subject to consent decrees that limit the emissions from subpart J process units.)

[19] 38 Fed. Reg., 15,406 (June 11, 1973).
[20] 72 Fed. Reg., 27,178 (May 14, 2007).

Subpart Ka: Standards of Performance for Volatile Organic Liquid Storage Vessels.[21]

On July 23, 1984, EPA proposed new emission standards of volatile organic compounds (VOC) from storage vessels containing volatile organic liquids (VOL). EPA used emissions data from the American Petroleum Institute (API) to establish the best demonstrated technology (BDT) for reducing VOC emissions from all types of VOL storage vessels. It was concluded that emission reductions could not accurately or feasibly be measured from VOL storage vessels. As a result, work practice and operational standards were set in lieu of numerical limits.

Subpart Na: Standards of Performance for Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction Commenced After January 20, 1983.[22]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated January 20, 1983, secondary PM emission standards (those not captured by the primary capture system) for new, modified, and reconstructed basic oxygen process furnaces (BOPFs), hot metal transfer stations, and skimming stations in iron and steel plants were developed.

The performance of secondary emission control systems were evaluated at 8 plants. Of the systems evaluated, those at 3 top blown furnace facilities and 1 bottom blown furnace facility were judged to represent the most effective systems of secondary emission control, based on roof monitor opacity observations. Secondary emissions from 2 top blown furnaces, each equipped with an open hood primary emission control system ducted to an ESP, were observed at the Bethlehem Steel Corporation facility at Bethlehem, Pennsylvania. Each furnace is partially enclosed by side walls, with no enclosure on the charging or tapping sides. The capture effectiveness of the secondary emission control system was evaluated on the basis of visible emissions observed exiting the process roof monitor over a number of steel production cycles. The opacities of roof monitor visible emissions were observed using the observation procedures of EPA Reference Method 9, with readings being taken at 15-second intervals. The data were analyzed by first computing the maximum 3-minute average opacity for each steel production cycle observed. Similarly, the second highest average opacity was computed for each cycle (without using any readings previously used in computing the maximum opacity). The means of the maximum and second highest averages were then determined. Note also that the data were analyzed according to 3- minute, rather than 6-minute, averages because a 3-minute average better reflects the brief duration of visible emissions characteristics of a BOPF steel production cycle. All of the 3- minute averages were segregated by furnace cycle. The data represent single furnace operation and include slag pot dumping, ladle deskulling, hot metal transfer, and teeming emissions. Analysis of the data indicates a mean maximum opacity of 1.4 percent and a second highest mean maximum opacity of 0.30 percent.

Secondary emissions from three top blown furnaces, equipped with an open hood primary emission control system ducted to two ESPs were also observed at the Jones and Laughlin (J&L) Steel Corporation shop at Aliquippa, Pennsylvania. Each furnace is enclosed on three sides. A

[21] 49 Fed. Reg., 29,698 (July 23, 1984).
[22] 48 Fed. Reg., 2,658 (January 20, 1983).

similar data analysis of the visible emissions data showed an overall mean maximum 3-minute average opacity of 3.9 percent, as compared to 1.4 percent for Bethlehem. The second highest mean opacity was 2.1 percent, as compared to 0.30 percent for Bethlehem.

Secondary emissions from a top blown vessel equipped with a closed hood primary emission control system and a separate secondary emission control system were observed at the Kaiser Steel facility at Fontana, California. Analysis of the data revealed a mean maximum opacity of 5.4 percent and a second highest mean opacity of 1.5 percent.

At the time of the 1983 preamble to the rule, only 3 plants in the United States operated bottom blown furnaces, also known as Q-BOP vessels. The capture efficiency of the secondary emission control system was evaluated for the Republic Steel Corporation facility in Chicago, Illinois. Analysis of the data indicated a mean maximum opacity of 17.5 percent, as compared to 5.4 percent for top blown furnace operation at the Kaiser facility where furnace enclosures and hooding are also used. The second highest mean opacity was 10.0 percent, as compared to 1.5 percent for Kaiser.

Performance test data were also examined to evaluate the collection efficiency of secondary emission control devices. Baghouses are generally used to collect secondary emissions, although a few scrubbers were currently used for secondary emission control. Performance test data for baghouses were evaluated at 7 plants. The data included 54 individual test runs made in accordance with EPA Reference Method 5. The range of all runs was from 2.28 to 22.8 mg/dscm (0.001 to 0.010 gr/dscf), with all except one run below 18.0 mg/dscm (0.0079 gr/dscf).

Visible emissions data for discharged gases leaving BOPF secondary emission baghouses were also obtained for 3 sources. Of the 664 3-minute averages computed, all but 25 were less than 1 percent, with 1 3-minute average showing 5 percent opacity and another showing 4.2 percent.

Based upon the available test data and EPA's rationale, the following limits were proposed: During operation of a top blown furnace, no 3-minute average of visible emissions from the shop roof monitor can exceed an opacity of 10 percent, except that one 3-minute average greater than 10 percent opacity, but not exceeding 20 percent opacity, could occur once per steel production cycle. During operation of a bottom blown furnace, no 3-minute average of visible emissions from the shop roof monitor can exceed an opacity of 30 percent, except that two 3- minute averages greater than 30 percent opacity, but not exceeding 60 percent opacity, could occur once per steel production cycle. To ensure the collection of captured emissions, a mass concentration standard of 23 mg/dscm (0.010 gr/dscf) and an opacity standard of 5 percent based on 3-minute averaging are proposed for emissions from a device used solely to collect secondary emissions from an affected facility.

For the control of secondary emissions from a top blown furnace, best demonstrated technology (BDT) is considered to be the use of the open hood primary emission control system to also control secondary emissions. For a bottom blown furnace, BDT is considered to be the use of a furnace enclosure with local hooding ducted to a baghouse. For the control of emissions from hot metal transfer and skimming stations, BDT is considered to be the use of local hooding

ducted to a baghouse. However, the proposed standards were performance standards and therefore did not require the use of specific control equipment.

Subpart P: Standards of Performance for Primary Copper Smelters;

Subpart Q: Standards of Performance for Primary Zinc Smelters; and

Subpart R: Standards of Performance for Primary Lead Smelters.[23]

On October 16, 1974, EPA proposed in the Federal Register standards of performance for three types of new smelters: copper, zinc and lead (Subparts P, Q, and R, respectively). According to the preamble of EPA's proposal:

> The bases for the proposed standards include a very extensive survey of the nonferrous smelting industry, including foreign smelting technology, plus the results of emission tests conducted by EPA. In each case the proposed standards reflect the degree of emission reduction achievable through the application of the best system of emission reduction which, taking into account the cost of achieving such reduction, the Administrator has determined has been adequately demonstrated. It is emphasized that the costs are considered reasonable for new and modified sources and that it is not implied that the same costs apply to the retrofitting of existing sources.

There was considerable pushback from the smelting industry prior to the proposal date, primarily focusing on the fact that most existing smelter technology yielded a weak SO_2 stream, which EPA acknowledged was not cost-effective to control. EPA stated that the proposed standards for SO_2 would require control technology as effective as double absorption (DA) sulfuric acid plants. The Agency acknowledged that the SO_2 emission limit in the proposed rule was initially based on EPA tests of single absorption (SA) sulfuric acid plants in combination with assessments by acid plant vendors of the emission control capabilities of DA acid plants. In the absence of domestic metallurgical DA acid plants during the early development of the proposed standards, and in recognition of the desirability of relating acid plant performance to domestic smelting practices, EPA initiated a testing program to characterize emissions from the best domestic metallurgical SA acid plants. The resulting data, including those from long-term continuous SO_2 monitoring of a SA acid plant which treated copper converter gases, provided information on the effects of gas stream fluctuations and acid plant catalyst deterioration on SO_2 emissions. In the later stages of development, after the first domestic metallurgical DA acid plant achieved normal operation, EPA began a continuous SO_2 monitoring program at the facility. That monitoring provided the data that served as the basis for the proposed SO_2 standards.

Another interesting aspect of the smelter NSPS is EPA dealing with environmental effects which would result from complying with the emission limits. The SO2 control technology required to comply with the proposed emission limits would produce large quantities of sulfur-bearing materials such as sulfuric acid and liquid sulfur dioxide. Industry expressed concerns that the

[23] 39 Fed. Reg., 37,040 (October 16, 1974).

large quantities of sulfuric acid would not be marketable and would require neutralization and subsequent disposal. The potential environmental effects of acid disposal, as well as the disposal of sulfates derived from scrubbing systems involve land and water pollution. Accordingly, EPA calculated the costs for the neutralization and disposal of sulfuric acid and included those costs in setting the proposed emission standards.

Subpart S: Standards of Performance for Primary Aluminum Reduction Plants.[24]

On October 23, 1974, EPA proposed standards of performance for new, primary aluminum plants. The major pollutant emitted from primary aluminum plants is fluoride compounds. The bases for the proposed standards include the results of measurements of emissions conducted by industry, the Environmental Protection Agency and local agencies; data derived from available technical literature; information gathered during visits to pollution control agencies and plants in the United States and abroad; and comments and suggestions solicited from experts.

Subpart T: Standards of Performance for the Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants;

Subpart U: Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants;

Subpart V: Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants;

Subpart W: Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants; and

Subpart X: Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities.[25]

On October 22, 1974, EPA proposed standards of performance for new affected facilities for five categories of sources within the phosphate fertilizer industry as follows: wet process phosphoric acid plants, superphosphoric acid plants, diammonium phosphate plants, triple superphosphate plants, and granular triple superphosphate storage facilities. These standards of performance were proposed as Subparts T, U, V, W and X. According to the preamble of EPA's proposal:

> The bases for the proposed standards include the results of measurements of emissions conducted by industry, the Environmental Protection Agency and local agencies; data derived from available technical literature; information gathered from pollution control agencies and plants in the United States ; and comments and suggestions solicited from experts. The proposed these standards reflects the degree of emission limitation achievable through the application of the best system of emission reduction, taking into account the cost of achieving such reduction, the Administrator has determined to be adequately demonstrated . "Background Information for Standards of Performance:

[24] 39 Fed. Reg., 37,730 (October 23, 1974).
[25] 39 Fed. Reg., 37,602 (October 22, 1974).

> Phosphate Fertilizer Industry," which presents the results of emission measurements and other factors considered in arriving at the proposed standards, including the types of controls systems and their costs, is available free of charge from the Emission Standards and Engineering Division, Environmental Protection Agency.

EPA also observed:

> The standards for new sources will require installation of high efficiency gas scrubbers. Such scrubbers (with internal packing to improve the absorption efficiency of the scrubbing fluid) are commonly used on all the categories of sources except superphosphoric acid (SPA). However, based on data from the other categories, engineering judgment indicates the standard recommended for SPA plants is achievable with the same type of equipment.

Subpart Y: Standards of Performance for Coal Preparation Plants.[26]

On April 28, 2008 EPA proposed to amend the emission limits for PM at coal preparation plants. According to the Section III "*Rationale for the Proposed Amendments*" contained in the preamble to the proposed rule, different approaches were used for thermal dryers and the coal handling equipment. The coal handling equipment consisted of pneumatic coal cleaning equipment and coal processing, conveying, storage, transfer and loading equipment.

For selection of the thermal dryer PM emissions limit, the proposed PM limit (0.020 gr/dscf) was chosen because that emissions level was currently being achieved by the thermal dryers located at the three facilities subject to the most stringent PM limits. Furthermore, based on performance testing data collected from these three facilities for 1997, 2000, 2003 and 2006, the average emission rates were able to meet the newly proposed limit.

For selection of the pneumatic coal cleaning and coal handling equipment PM emissions limit, a best demonstrated technology (BDT) assessment was performed. It was determined that the BDT was dependent on the type of coal that was processed and the configuration of the equipment. As a result, different PM emissions limits and or opacity standards were selected based on the applicable BDT.

Both PM and opacity standards were set for new or reconstructed affected facilities that process coals other than bituminous and modified affected facilities that are enclosed and process coals other than bituminous. For all other coal processing and conveying equipment, coal storage systems, and transfer and loading systems, only an opacity standard was chosen.

For determination of the opacity standard that reflects BDT for facilities that vent PM emissions through a stack, 38 permits for facilities with baghouses were reviewed. Of those permits reviewed, 35 contained opacity limits of 5%. It was concluded that BDT for a baghouse equipped coal preparation plant is 5% opacity. In addition, test reports collected in support of

[26] 73 Fed. Reg., 22,901 (April 28, 2008).

the 40 CFR Part 60, subpart OOO[27] review were considered. Results from all 102 of the opacity performance tests showed maximum opacity readings of 5% or less.
For determination of the opacity standard that reflects BDT for facilities that do not vent PM emissions through a stack, 383 Method 9 performance tests were reviewed from facilities processing non-metallic minerals using wet suppression. Again it was concluded that emissions from these types of facilities is comparable to the non-enclosed coal handling facilities. Of the 383 Method 9 opacity performance tests that were reviewed, 91% of the tests had readings of 5% or less. It was concluded that BDT for these types of facilities is 5% opacity.

For determination of the PM emissions limit, 47 baghouse permits were reviewed. Twenty-four of those permits had limits at the proposed limits and 22 had limits at or near the proposed limit. In addition, 143 performance tests from the subpart OOO review were considered. 71% of those test results showed PM emissions at or below the proposed limit.

Subpart Z: Standards of Performance for Ferroalloy Production Facilities.[28]

On October 21, 1974, EPA proposed standards of performance for new ferroalloy production facilities. The proposed standards were based on the results of emission tests conducted by industry, EPA and local agencies; data derived from available technical literature; information gathered during plant visits both in the U.S. and abroad; and comments provided by experts in the field. EPA stated that the same type of control then currently used in industry (i.e., baghouses and wet scrubbers) would be required to meet the proposed PM emission limits.

Subpart AA: Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels.[29]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated August 17, 1983, PM emission standards for new, modified, and reconstructed electric arc furnaces (EAFs), argon-oxygen decarburization (AOD) vessels, and their associated dust handling systems were revised.

Particulate matter and visible emission opacity limits were selected based on the performance of the capture and control technologies in the steel plant industry. Twenty-seven hours of opacity observations were made of shop roof visible emissions at two plants that utilized the capture systems upon which the proposed standards are based. These measurements show that the opacity of shop roof visible emissions is 5 percent or less. Therefore, the proposed revised standards limit the opacity of visible emissions from the shop roof monitors to less than 6 percent for all operations.

Emissions data for particular matter were gathered from 13 fabric filters at both carbon steel and specialty steel shops. These data were obtained from compliance tests or from EPA source tests. The test data show that emissions from fabric filters are less than 7 mg/dscm (0.0031 gr/dscf).

[27] Subpart OOO applies to non-metallic mineral processing facilities and the emissions from these sources were concluded to be representative of the emissions expected from coal handling plants equipped with baghouses.
[28] 39 Fed. Reg., 37,470 (October 21, 1974).
[29] 48 Fed. Reg., 37,338 (August 17, 1983).

The existing standards of performance limit particulate matter emissions to 12 mg/dscm (0.0052 gr/dscf). However, if the emission limit were lowered to 7 mg/dscm (0.0031 gr/dscf), the capital costs of fabric filters could increase by as much as 25 percent. This increase in costs results from the increased control device air-to-cloth ratio or more efficient filter fabric which would be needed to assure compliance with the more stringent emission limit. This increased cost is not considered reasonable in view of the small additional emission reduction it would achieve. Therefore, the mass emission standard for control devices covered by the proposed revised standards remained at 12 mg/dscm (0.0052 gr/dscf).
Forty-three hours of visible emission data were obtained using Reference Method 9 for emissions from 10 tests on fabric filters at both carbon steel and specialty steel shops. The maximum 6-minute average opacity observed from the 10 tests was zero percent. In addition, over 31 hours of visible emission data were obtained using continuous opacity monitors from two tests on fabric filters. The maximum 6-minute average opacity observation was 2.8 percent from one continuous capacity monitor and the data obtained from the other continuous opacity monitor averaged 2.3 percent opacity, with a 95 percent confidence interval of 2.2 to 2.5 percent opacity. Therefore, the data show that the existing 3 percent opacity standard for visible emissions is achievable by a well-designed and properly operated fabric filter. As with the particulate matter standard, revision of the visible emission standard for control devices to a lower level was not proposed.

Opacity observations of visible emissions from the operation of dust handling equipment at both carbon and specialty steel shops confirm that the opacity of visible emissions from dust handling equipment operations can be controlled to the existing limit of 10 percent. Therefore, a revision of the existing standard was not proposed.

Based upon the available test data and EPA's rationale, the proposed standards would limit PM emissions from pollution control devices installed on EAFs and AOD vessels to 12 mg/dscm (0.0052 gr/dscf) and visible emissions from these sources to less than 3 percent opacity. Visible emissions from EAFs and AOD vessels that exit from the shop roof would be limited to 6 percent opacity. Visible emissions from dust handling systems would be limited to 10 percent opacity. In addition, monitoring of the opacity from control devices installed on EAFs and AOD vessels would require an continuous opacity monitoring system (COMS) unless a positive-pressure fabric filter was used.

Subpart BB: Standards of Performance for Kraft Pulp Mills.[30]

On September 24, 1976, EPA proposed standards of performance for new kraft pulp mills. According to the preamble of EPA's proposal:

> The bases for the proposed standards include information derived from (1) available technical literature on the kraft pulping industry and emission control of the kraft pulping process, (2) published studies sponsored by EPA -of emission control of the kraft pulping process, (3) information gathered during visits to pollution control agencies and kraft pulp mills in the United States, (4) comments

[30] 41 Fed. Reg., 42,012 (February 24, 1976).

and suggestions solicited from experts, and (5) the results of measurements of emissions conducted by EPA and by the industry.

Subpart CC: Standards of Performance for Glass Manufacturing Plants.[31]

On June 15, 1979, EPA proposed standards of performance for new glass manufacturing plants. EPA identified three best systems of emission reduction for PM: electrostatic precipitators, fabric filters and venturi scrubbers. EPA used Method 5 stack testing data as well as data from the Los Angles Air Pollution Control District PM test method to set PM emission limits for the four different types of glass manufacturing furnaces: flat glass, container glass, pressed and blown glass, and wool fiberglass.

Subpart DD: Standards of Performance for Grain Elevators.[32]

On January 13, 1977, EPA proposed standards of performance for new grain elevator facilities. The proposed standards for grain elevators are based primarily on results of a previous EPA-sponsored investigation of air pollution emissions and control technologies in the grain and feed industry. This study included the responses from 509 owners/operators of elevators throughout the country to a questionnaire on the air pollution aspects of their operations. EPA's proposed standards are also based on data concerning control systems and methods of process operation obtained from onsite observations of plant operations and control systems, consultation with industry representatives and manufacturers of control systems and devices, emissions tests conducted by EPA and operators of grain elevators, and meetings with industry associations.

Subpart EE: Standards of Performance for Surface Coating of Metal Furniture.[33]

On November 28, 1980, EPA proposed to limit VOC emissions from new, modified and reconstructed metal furniture surface coating facilities. EPA identified three control technologies for reducing VOC emissions from metal furniture coating lines: (1) low-organic-solvent coatings, (2) transfer efficiency improvements based on coating application technique and (3) emissions control systems. EPA proposed an emission limit of 0.70 kilogram of VOC per liter of coating solids applied. EPA had information showing that this emission limit could be achieved employing any of the three above-listed control technologies.

Subpart GG: Standards of Performance for Stationary Gas Turbines.[34]

On October 3, 1977, EPA proposed standards of performance for Stationary Gas Turbines. EPA identified three potential control technologies for reducing NO_X emissions from stationary gas

[31] 44 Fed. Reg., 34,840 (June 15, 1979).
[32] 42 Fed. Reg., 2,842 (January 13, 1977).
[33] 45 Fed. Reg., 79,390 (November 28, 1980).
[34] 42 Fed. Reg., 53,782 (October 3, 1977).

turbines: wet controls, dry controls and catalytic exhaust cleanup. Wet controls involve the injection of steam or water into the combustion zone to reduce peak flame temperatures, thereby reducing NO_X formation. Dry controls consist primarily of design modifications which govern combustion conditions to reduce NO_X formation. It is interesting to note what EPA had to say about catalytic controls. According to EPA, "catalytic exhaust gas cleanup consists of NO_X reduction by ammonia in the presence of a catalyst. While laboratory tests are very promising, this technique is not demonstrated for stationary gas turbines."

EPA reviewed emissions data from gas turbines with wet controls burning both gaseous fuels as well as distillate fuels. While the data for distillate firing showed was slightly higher NO_X emissions, EPA concluded only one emission limit was justified. Based on the emission data and allowing for some uncertainly in the database, EPA proposed a single NO_X emission limit of 75 parts per million corrected to 15 percent O_2.

Subpart HH: Standards of Performance for Lime Manufacturing Plants.[35]

On May 3, 1977, EPA proposed standards of performance for lime manufacturing plants. According to the preamble of EPA's proposal:

> The proposed standards were developed based on information derived from (1) available technical literature on the lime manufacturing industry and applicable emission control technology, (2) technical studies performed for EPA by independent research organizations, (3) information obtained from the industry during visits to lime plants and meeting with various representatives of the industry, (4) comments and suggestions solicited from experts, and (5) the results of emission measurements conducted by EPA and the industry.

Subpart LL: Standards of Performance for Metallic Mineral Processing Plants.[36]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated August 24, 1982, EPA proposed particulate matter (PM) standards for new, modified, and reconstructed facilities at metallic mineral processing plants.

Metallic mineral processing plants are considered sources of PM, NO_x, and SO_2. However, EPA proposed only PM for control since the Agency SO_2 considered insignificant due to low-sulfur natural gas combustion (by the thermal dryer) and effective control techniques for NO_x had not yet been demonstrated at the time of the original proposal.

Based upon industry information, an effective control device used in the mineral processing industry is the fabric filter or baghouse. Data gathered during emission tests on baghouse units indicate that the size distribution of PM, the rock type processed, and the process equipment do

[35] 42 Fed. Reg., 22,506 (May 3, 1977).
[36] 47 Fed. Reg., 36,859 (August 24, 1982).

not substantially affect baghouse performance. Other collection devices used in the metallic mineral processing industry include dry inertial cyclones and wet scrubbers. In determining the basis for the proposed standards, EPA considered three regulatory alternatives: (1) to set no standards, (2) to set standards based on the performance of 15-inch pressure drop wet scrubbers under worst-case conditions, or (3) to set standards based on the performance of 30-inch pressure drop wet scrubbers under worst-case conditions. Because baghouses could provide emission control equivalent to 30-inch wet scrubbers under most conditions at metallic minerals plants, this control option was also considered.

EPA's selection of emission limits was based on the performance of the best systems of continuous emission reduction for the metallic mineral processing industry. Because the proposed standard is setting emission limits for both capture devices (such as hoods arid enclosures) and control devices (such as baghouses and wet scrubbers), both capture and control devices required evaluation. In order to broaden the range of conditions considered for the performance of the control equipment, test data for non-metallic mineral processing facilities are also included in the data base considered in the selection of emission limits. Data from the non-metallic mineral industries were also transferred to the metallic mineral industries for several reasons – much of the process equipment relevant to the proposed standards is similar in the metallic and non-metallic processing industries.

Finally, a comparison of non-metallic and metallic test data indicated that several sources tested in the nonmetallic mineral industries provided more difficult control conditions than those tested in the metallic mineral industries. These tests provided information on the performance of baghouses under rigorous conditions, and thus increased the understanding of the range of circumstances in which control devices might be used. These tests also helped to anticipate the performance of baghouses under potential "worst-case" conditions in the metallic mineral industries.

For fugitive (visible) emissions, a total of 53 operations at 13 plants were tested using EPA Reference Method 9. The maximum six-minute average at 35 of the 53 processes tested was 0 percent. 2 of the processes exceeded 5 percent opacity at any given time. 1 process showed maximum visible emissions of 8 percent opacity (via a grizzly screen) and 1 other process showed maximum visible emissions of 9 percent opacity.

For stack emissions of PM, PM emissions were measured from 25 baghouses used to control emissions at crushing, screening, conveying, and grinding operations at 13 plants in both the metallic and non-metallic mineral processing industries. The PM concentrations from these baghouses averaged 0.014 g/dscm (0.006 gr/dscf), and never exceeded 0.041 g/dscm (0.018 gr/dscf) as a 3-run average. Tests of 13 wet scrubbers at 7 installations in the metallic minerals industry indicate that low energy wet scrubbers (6- to 10-inch pressure drop) were able to reduce emissions to less than 0.05 g/dscm (0.02 gr/dscf).

In order to determine the performance of wet scrubbers under worst-case conditions, additional modelling of high energy wet scrubbers was performed. These modelling exercises demonstrated that a 30-inch pressure drop wet scrubber could reduce worst-case emissions to 0.05 g/dscm (0.02 gr/dscf). The test data summarized above from the Background Information

Document (BID) indicate wet scrubbers are best demonstrated technology and can be used to achieve an emission limit of 0.05 g/dscm (0.02 gr/dscf). In conditions of relatively low inlet particle concentrations and large particle size, lower energy scrubbers may be sufficient. In those cases where moisture condensation is not a problem, baghouses can also achieve an emission level of 0.05 g/dscm (0.02 gr/dscf).

EPA also obtained stack opacity data. At 21 of 25 baghouses tested, the maximum 6-minute average was 0 percent opacity. At three of the remaining four baghouses, the maximum 6-minute opacity was 1 percent. The remaining baghouse showed visible emissions of up to 6 percent opacity. Therefore, EPA proposed a 7-percent opacity standard. Stack emission opacity data collected during the tests of wet scrubbers were inconclusive due to their high variability. Some of the highest opacity readings (e.g., 25 percent) were observed at low outlet particle concentrations (e.g., 0.006 gr/dscf), while at other facilities with outlet concentrations closer to the stack emission limits, opacity was essentially zero. Therefore, an opacity standard is not being proposed for wet scrubbers. Instead, the monitoring of the operating parameters of wet scrubbers (e.g., pressure drop and scrubber liquid flow rate) would be required by the proposed standard.

Based upon the available test data and EPA's analysis, the Agency proposed the following limits: process fugitive emissions of PM not collected by a capture system would be limited to 10 percent opacity. The proposed PM limit for emissions vented through a control device would be limited to 0.05 g/dscm (0.02 gr/dscf). Stack emissions would also be limited to 7 percent opacity: however, the opacity standard would not apply to sources that use wet scrubbers to control the PM emissions. The affected facilities from a metallic mineral processing plant would be each crusher, screen, bucket elevator, conveyor belt transfer point, product packaging station, storage bin, enclosed storage area, truck loading station, truck unloading station, railcar unloading station, and thermal dryer.

Subpart MM: Standards of Performance for Automotive and Light-Duty Truck Surface Coating Operations.[37]

On October 5, 1979, EPA proposed standards of performance for automotive and light-duty truck surface coating operations. EPA identified the best systems to reduce the emission of volatile organic compounds (VOCs) from automobile and light-duty surface coating operations to be (1) the use of coatings with low organic solvent content or (2) add-on emission controls such as incineration, or (3) a combination of the two. EPA proposed numerical emission limits based on Method 24 (Candidate 1), which determines VOC content of coatings expressed as mass of carbon. EPA proposed 0.10 kilogram (kg) of VOC per liter of applied coating solids for prime coat operations; 0.84 kg of VOC per liter of applied coating solids for guide coat operations; and 0.84 kg of VOC per liter of applied coating solids for topcoat operations.

During EPA's development of the proposed emission limits, industry raised questions concerning the validity of data based on Method 24 (Candidate 1) because the ratio of

[37] 44 Fed. Reg., 57,792 (October 5, 1979).

mass of carbon to mass of VOC varies significantly in the solvents used in automotive coatings. Accordingly, EPA developed and proposed alternative emission limits based on Method 24 (Candidate 2), which determines VOC content in terms of mass of volatile organics instead of mass of carbon. The proposed alternative emission limits were 0.16 kg of VOC per liter of applied coating solids for prime coat operations; 1.36 kg of VOC per liter of applied coating solids for guide coat operations; and 1.36 kg of VOC per liter of applied coating solids for topcoat operations. EPA finalized Subpart MM based on Method 24 (Candidate 2), which determines VOC content in terms of mass of volatile organics instead of mass of carbon.

Subpart NN: Standards of Performance for Phosphate Rock Plants.[38]

On September 21, 1979, EPA proposed standards of performance for new phosphate rock plants. EPA identified two best systems of emission reduction for PM: fabric filters and venturi scrubbers. EPA stated a third technology, electrostatic precipitators, were equally effective but somewhat less cost-effective due to large volumetric flow rates. EPA set PM emission limits for three different phosphate rock processes: dryers, calciners and grinders. For each PM emission standard, EPA had stack testing data from both tests conducted by the Agency as well as tests conducted by plant owners. EPA set opacity standards for the three phosphate rock processes and also for ground rock handling and storage systems. In each case, EPA had numerous hours of visible emission data upon which to base the opacity standards.

Subpart PP: Standards of Performance for Ammonium Sulfate Manufacture.[39]

On February 4, 1980, EPA proposed standards of performance for new, modified and reconstructed phosphate rock plants. Based on a survey of the ammonium sulfate production industry, EPA identified four plants for EPA Method 5 particulate emission testing. These four ammonium sulfate manufacturing plants were then tested by EPA in order to evaluate control techniques currently used for controlling particulate emissions from ammonium sulfate dryers. During the Method 5 PM tests, opacity readings were also recorded. An ammonium sulfate plant owner/operator provided additional emission test data on units equipped with wet scrubbers. Based on EPA analysis of the emission testing data, the Agency proposed a PM limit of 0.30 pound of particulate per ton of ammonium sulfate produced and exhaust gases and an opacity limit of 15 percent.

Subpart TT: Standards of Performance for Metal Coil Surface Coating.[40]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated January 5, 1981, VOC emission standards for new, modified, and reconstructed metal coil surface operations were developed.

[38] 44 Fed. Reg., 54,970 (September 21, 1979).
[39] 45 Fed. Reg., 7,758 (February 4, 1980).
[40] 46 Fed. Reg., 1,102 (January 5, 1981).

Based upon industry information, it was stated that the only emission control device that has been identified as effective in controlling VOC emissions from coil coating operations is either a thermal or catalytic incinerator. The results of seven stack emissions tests (from a national industry-wide total of 109 coil coating plants containing an estimated 147 coil coating lines) indicated that thermal incinerators can achieve greater than 95 percent reduction in VOC emissions when they are operated at temperatures of 760 ^{o}C (1,400 ^{o}F) or greater. The second general technique for reducing VOC emissions would be to reduce the amount of VOC used in the coating process. Data submitted by coating manufacturers indicate that the VOC content in coatings ranges from 0.07 to 0.54 kg/l of solids and that most are in the range of 0.11 to 0.28 kg/l of solids.

Based upon the industry data and EPA's rationale, the following three-step standard was proposed: (1) for coatings with VOC contents of 1.4 or more kg/l of coating solids, the emission standard is 90 percent reduction in VOC emissions, (2) for coatings with VOC contents of 0.28 to 1.4 kg/l of coating solids, the emission standard is 0.14 kg VOC/l of coating solids using a VOC capture system, and (3) for coatings with VOC contents of below 0.28 kg/l of coating solids, the emission standard is 0.28 kg/l without having to use any controls.

Subpart UU: Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.[41]

EPA had test data from four asphalt roofing plants, which demonstrated that particulate emissions from saturators and asphalt storage tanks could be effectively controlled to essentially the same emission level by any one of three pollution control devices: afterburner (A/B], high velocity air filter (HVAF), or electrostatic precipitator (ESP). EPA determined that to achieve the best level of' control, each of the control devices must be operated at the proper temperature. EPA conducted survey of asphalt roofing manufacturers and State, regional, and local agencies to identify well-controlled asphalt roofing plants. As a result of this survey, EPA visited 27 asphalt roofing plants were visited in order to select the best plants for emissions testing. During the plant visits, opacity readings were taken at control device outlets, the control devices were visually inspected, engineering drawings were examined, and emission reports, when available, were studied. The information collected during the plant inspections was evaluated, and the best-controlled plants were selected for emissions testing. The test results indicated that an afterburner controlling emissions from a saturator and operating at a temperature above 649°C (1200°F) could achieve about a 93 percent emission reduction. The tests also indicated that an ESP or HVAF could achieve about a 93 percent particulate emission reduction if the saturator exhaust gases are cooled below 60°C (140F). EPA states in the preamble, "the proposed standards are based on the pollution control devices that were tested."

Subpart VV: Standards of Performance for Equipment Leaks of VOCs in the Synthetic Organic Chemical Manufacturing Industry and Petroleum Refineries. [42]

On November 7, 2006, EPA proposed to amend the standards of performance for equipment leaks of Volatile Organic Compounds (VOCs) in the synthetic organic chemicals manufacturing

[41] 45 Fed. Reg., 76,404 (November 18, 1980).
[42] 71 Fed. Reg., 65,302 (November 7, 2006).

industry (SOCMI) and petroleum refineries[43]. The primary change proposed in this amendment was a change in the conditions that define leaks from pumps and valves. The rate at which a leak is determined to be present was reduced as a result of this amendment. The rates that were chosen were simply based upon definitions found in other Federal equipment leak rules (e.g. NESHAP), State rules (e.g. California's and Texas' applicable equipment leak rate provisions) and various consent decrees. However, all of the existing facilities were in compliance with the proposed leak rate limits.

Subpart WW: Standards of Performance for the Beverage Can Surface Coating Industry.[44]

On November 26, 1980, EPA proposed standards of performance for new, modified and reconstructed beverage can surface coating operations. EPA identified three control technologies for reducing VOC emissions from beverage can surface coating operations: (1) low VOC content coatings, and (2) solvent-borne coating systems with emissions capture and control systems.

Subpart XX: Standards of Performance for Bulk Gasoline Terminals.[45]

On December 17, 1980, EPA proposed standards of performance for new, modified and reconstructed bulk Gasoline terminals. EPA evaluated several control technologies for reducing the emission of volatile organic compounds (VOCs) including: carbon absorption, thermal oxidation, refrigeration, compression-refrigeration-condensation, compression-refrigeration-condensation, and lean oil absorption. EPA had comprehensive emission test data for all six of the above-listed control technologies. In fact, EPA had a total of 22 tests reflecting 61 days of testing. EPA proposed to limit the emission of VOCs to 35 milligrams per liter of gasoline loaded.

Subpart BBB: Standards of Performance for Rubber Tire Manufacturing Industry.[46]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated January 20, 1983, EPA proposed VOC emission standards for new, modified, and reconstructed sources within rubber tire manufacturing plants.

Based on the best systems of continuous emission reduction, the proposed standards consisted of the following numerical emission limits: each undertread cementing operation and each sidewall cementing operation where more than 25 grams of VOC are used per tire would be required to reduce emissions by at least 75 percent. Undertread cementing and sidewall cementing operations that use less than 25 g/tire would not be required to install emission reduction systems. Each tread end and bead cementing facility would be required to limit emissions to no more than 10 g/tire. Each inside green tire spray operation would be required to limit emissions

[43] Subparts DDD, GGG, and KKK of 40 CFR part 60 also set specific standards of performance for VOCs. Although these are for other source categories (e.g. petroleum refineries), they cross-reference the requirements in subpart VV. However, each subpart has its own source-category-specific requirements.
[44] 45 Fed. Reg., 78,980 (November 26, 1980).
[45] 45 Fed. Reg., 83,126 (December 17, 1980).
[46] 48 Fed. Reg., 2,676 (January 20, 1983).

to no more than 1.2 g/ tire, and each outside green tire spray operation would be required to limit emissions to no more than 9.3 g/tire. Each Michelin-B operation would be required to reduce emissions by at least 75 percent. Each Michelin-A operation and each Michelin-C-automatic operation would be required to reduce emissions by at least 65 percent. Based on industry experience, EPA determined that these emission limits reflect application of the best demonstrated system of emission reduction (BDT) at each affected facility in a rubber tire manufacturing plant.

Using the technical literature and industry experience, EPA's analysis indicated the proposed standards would limit VOC emissions from the following sources: undertread cementing operations, sidewall cementing operations, tread end cementing operations, bead cementing operations, inside green tire spraying operations, outside green tire spraying operations, and each Michelin-A, -B, and –C automatic operation, where components for tires which have a bead diameter up to an including 19.7 inches and cross section dimension up to an including 12.8 inches are mass produced in assembly-line fashion. To meet the proposed standards for each undertread cementing and sidewall cementing operation, an owner/operator would have the option of using less solvent and maintaining VOC emissions at or below 25 grams per tire without the use of an emission reduction system, or installing a 75 percent efficient emission reduction system if solvent use exceeds 25 g/tire. For each tread end cementing and each bead cementing operation, VOC emissions would be limited to 10 grams per tire without the use of an emission reduction system. For each inside green tire spraying operation, VOC emissions would be limited to 1.2 grams per tire without the use of an emission reduction system. For each outside green tire spraying operation, VOC emissions would be limited to 9.3 grams per tire without the use of an emission reduction system. The proposed emission standards would also require 75 percent emission reduction for each Michelin-B operation and 65 percent emission reduction for each Michelin-A and Michelin-C operation.

Subpart DDD: Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry.[47]

According to the Section IV *"Rationale"* contained in the preamble to the proposed rule dated September 30, 1987, EPA proposed VOC emission standards for new, modified, and reconstructed polypropylene, polyethylene, polystyrene, and polyester (i.e., polymer) production plants.

As described in the background information document (BID), test data show that certain types of flares can achieve 98 percent VOC emission reduction under specific conditions and that only flares operating under these conditions achieve a 98 percent VOC emission reduction: the net heating value of the flared gas must not be less than 300 Btu/scf for a steam-assisted or air-assisted flare, or less than 200 Btu/scf for a non-assisted flare. In addition, combustion devices such as thermal and catalytic incinerators, process heaters, and boilers can achieve a 98 weight percent VOC reduction.

Further analysis indicates that the use of refrigerated condensers, cooling the gas stream discharged from the material recovery section to -26 degrees Centigrade (-15 ^{o}F), would reduce

[47] 55 Fed. Reg., 26,953 (June 29, 1990).

VOC emissions to 0.0036 kg VOC per Mg of product. Consequently, based on this analysis and taking into account allowable temperature monitor accuracy, an emission limit of 0.0036 kg TOC per Mg of polystyrene product or, as a surrogate, a limit of -25 °C (-13 ^{o}F) on the outlet gas temperature are included in the proposed standards limiting VOC emissions from the material recovery section of general purpose or impact polystyrene production plants using a continuous production process.

Based on other data summarized in the BID, VOC emissions discharged from the recovery part of polyethylene terephthalate production plants are 0.02 kilograms per Mg or less. Consequently, the proposed standards would limit TOC emissions from the recovery section of this system to 0.02 kilograms per Mg of polyethylene terephthalate produced. The data available show that a well-operated spray condenser is capable of reducing the concentration of ethylene glycol in the cooling water exiting the vacuum system to 0.35 weight percent or less, based on a 14-day rolling average, in plants where a low viscosity product is produced or where a high viscosity product is produced using a single end finisher.

As described in the BID, the reaction of dimethyl terephthalate and ethylene glycol produces bis-hydroxyethylterephthalate and methanol. Methanol emissions from the material recovery section are around 0.18 kg VOC per Mg of product. Analysis indicates that the use of refrigerated condensers, cooling the methanol stream to -25 °C (-13 ^{o}F), would reduce VOC emissions to 0.0027kg VOC per Mg of product. Data summarized in the BID show that the condensers controlling VOC emissions from the esterifiers in plants using theterephthalic acid process are capable of reducing emissions to 0.04 kilograms VOC per Mg of product or less.

Subpart FFF: Standards of Performance for Flexible Vinyl Coating and Printing Operations.[48]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated January 18, 1983, EPA proposed VOC emission standards for new, modified, and reconstructed flexible vinyl printing and coating operations.

EPA conducted two testing programs at a wall covering plant. After carefully studying the results from both testing programs, the Agency determined that data from the second testing program are representative of normal operations of the print line tested and for new print lines likely to be installed in the future. Data from the first testing program were not used in development of the standard because air management around the print line was adversely affected by air flow into and out of the room. An overhead fan designed to supply outside air to the room and a room exhaust wall fan cause such turbulence around the rotogravure print stations that capture efficiency was lowered below design expectations. Both of these fans lacked adequate distribution systems and this poor air management caused the excessive turbulence.

The proposed standard requires an 85 percent reduction in VOC emissions. This reduction is calculated as the product of the capture system efficiency times the carbon adsorber efficiency. During seven test runs conducted during actual printing operations, capture system efficiency

[48] 48 Fed. Reg., 2,276 (January 18, 1983).

ranged from 90 to 95 percent, averaging 92 percent. The average efficiency of the three lowest test runs was 90 percent and therefore 90 percent capture system efficiency was used in setting the standard. The efficiency of the carbon adsorber ranged from 99 to nearly 100 percent during three test periods. However, a carbon adsorber efficiency of 95 percent was used in determining the level of the proposed standard for three reasons. First, the vendor of the carbon adsorption unit used at the vinyl printing plant tested guarantees the unit to be 95 percent efficient. The second reason for using the 95 percent efficiency was that the carbon adsorber efficiencies recorded during the testing are somewhat higher than would be the case under design conditions. At the plant tested, the system was new, it was operated only eight hours per day, and the carbon bed was regenerated twice at the end of each day. The second regeneration increases efficiency by almost completely removing the remaining solvent left on the carbon. Finally, carbon adsorber efficiencies of 95 percent have been demonstrated and used as the basis for standards of performance for two other web coating industries. Based on the test results, the overall control requirement of 85 percent was selected as the level that can be achieved by the best demonstrated technology in all control situations expected to occur at new, modified, and reconstructed facilities.

In addition, considering that as solvent content decreases, the emissions reduction and thus the benefit of add-on controls decreases, EPA examined costs and benefits of controls on low solvent inks. The VOC content per unit of ink solids in currently used solvent-borne inks ranged from 2.3 to 19 kg VOC per kg ink solids and could not be lowered by the substitution of water for organic solvent. The resins and organic solvents in present solvent-borne formulations are not compatible with water. Waterborne inks will use different resins and solvents from those presently used in solvent-borne inks. Data and information gathered from several industry sources and ink suppliers indicate that the VOC content of waterborne inks being developed and used ranges from 0.0 kg VOC per kg ink solids to 0.75 kg VOC per kg ink solids. It is reported that the VOC content in these waterborne inks can only exceed 0.75 kg VOC per kg ink solids by a small degree because of technical .problems involving the high boiling point characteristics of the organic solvents used. Increased quantities of these high boiling point solvents in the inks inhibit the drying process .and cause product quality problems. Additional solvent is sometimes introduced at the press for viscosity control purposes and could possibly cause the total VOC content of the ink to be as much as 1.0 k8 per kg ink solids. However, the cost of installing, operating, and maintaining either carbon adsorbers or incinerators as control devices at plants using inks with less than 1.0 kg VOC per kg ink solids would be exorbitant, considering the small emission reduction which would be achieved for these low solvent inks. At a typical plant, emissions would be reduced by 65 mg per year at an annualized cost of $300,000. Because of the exorbitant cost, additional control for affected facilities at which the inks used contain less than 1.0 kg VOC per kg ink solids would not reflect the BDT, considering costs, and is therefore not required by the proposed standard. There is no precise basis for a limit of 1.0 kg of VOC per kg ink solids. As discussed above, however, EPA believes that solvent-borne inks with a VOC content in the 1.0 to 2.3 kg VOC per kg ink solids range would not be developed in the absence of a standard due to technical application problems involving ink viscosity and drying of the printed web. EPA does not want to unintentionally encourage the development of inks in this range. A standard with a cut-off at 1.0 kg VOC per kg ink solids achieves the greatest reduction possible without exorbitant cost and EPA is therefore proposing 1.0 kg VOC per kg ink solids as the level below which the percent reduction standard would not apply. The cost of carbon

adsorber control systems for inks with VOC contents greater than 2.3 kg VOC per kg ink solids would be reasonable.

Based upon EPA's analysis of available test data, the proposed standards would require each rotogravure printing line used to print or coat flexible vinyl products to either reduce gaseous VOC emissions by 85 percent or use inks with an average VOC content of less than 1.0 kg VOC per kg ink solids.

Subpart HHH: Standards of Performance for Synthetic Fiber Production Facilities.[49]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated November 23, 1982, EPA proposed VOC emission standards for new, modified, and reconstructed synthetic fiber production facilities that use "solvent-spinning processes."

EPA collected process and emissions data from about 20 fiber producing facilities in developing its technical data base. EPA testing programs were conducted at two acrylic fiber plants in order to evaluate uncontrolled emission rates at various process points as well as to verify capture and control device efficiencies. Existing baseline emission rates were found to range from about 14 kg to 56 kg of VOC per Mg of solvent use. Based on emission data gathered at an acrylic fiber plant operating with what EPA considers the best vapor capture system in the industry, and solvent-use and recovery data provided by that plant, a capture efficiency of over 90 percent was determined to be achievable by enclosures around various process emission points.

Because they are completely enclosed, a capture efficiency of 100 percent could be expected for dryers. The emission test data combined with data submitted from four other plants also demonstrated that control device efficiencies of 98 percent are being achieved. Thus, on those points not served by primary recovery system – for example, spinning solution preparation, washing, crimping, drawing, etc., overall emission control of 88 percent could be expected. Since capture at dryers is essentially total, overall emission control and recovery efficiency would be 98 percent. However, since 94 to 97 percent of the solvent used in fiber production is already recovered from the spinning cell or cabinet by the primary recovery system, the incremental effect is to raise the overall recovery to near 99 percent. Based on the uncontrolled emissions from the model plants, control of additional specific process steps in the wet and dry spinning of acrylic fibers would result in emission rates of 5 to 8 kg of VOC emissions per Mg of total solvent feed, respectively, on a long-term basis. Control of additional process steps in the manufacture of all other fiber types would result in controlled emission rates of 14 to 15 kg VOC emissions per Mg total solvent feed on a long-term basis.

Emission rates for acrylic fiber production facilities range from 5 to 8 kg of VOC per Mg of solvent used. To ensure that all acrylic fiber production facilities could achieve the proposed standard, the emission limit achievable under the worst case, 8 kg VOC per Mg of solvent feed, was selected. All affected facilities producing non-acrylic fiber could be controlled by either of two technologies: installation of capture and control equipment to service emission sources not controlled under baseline conditions or use of plant air management. Emission rates of 14 to 15

[49]47 Fed. Reg., 52,932 (November 23, 1982).

kg VOC per Mg solvent feed can be achieved by using the enclosure method, and an emission rate of 14 kg VOC emissions per Mg solvent feed is achievable through the use of plant air management. Enforcement of individual emission limits for different non-acrylic fiber processes is not possible, since an affected facility may contain more than one fiber process. Consequently, the least stringent emission rate, 15 kg of VOC per Mg of solvent feed, was selected to ensure that any affected facility in this subcategory would technically be capable of meeting the standard regardless of the fiber being produced.

Based upon the available test data and EPA's analysis, the proposed standards would require that VOC emissions from sources that produce acrylic fibers be limited to 10 kg per Mg of solvent fed to the spinning solution preparation area or precipitation bath. VOC emissions from sources that produce non-acrylic fibers be limited to 17 kg per Mg of solvent fed to the spinning solution preparation area or precipitation bath.

Subpart III: Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes.[50]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated October 21, 1983, EPA proposed VOC emission standards for new, modified, and reconstructed synthetic organic chemical manufacturing (SOCMI) air oxidation facilities. Based upon industry experience and operating histories, an incinerator (also known as a thermal oxidizer) was deemed able to achieve 98 percent control or 20 ppmv VOC in the outlet gas.

Thus, this device was the candidate for BDT for this particular source category, which is a control technology available to all SOCMI air oxidation processes. In the preamble, EPA stated that "tests were performed" (although no specific number of tests or test results were provided in the preamble) on the destruction efficiency of incinerators operating at various temperatures (1,300 to 1,500 ^{o}F) and residence times (0.5 to 1.5 seconds). These tests showed a destruction efficiency of 98 percent to be achievable. Moreover, available test data showed that the lowest concentrations achievable by combustion of inlet streams below approximately 2,000 ppmv is 20 ppmv. Based upon EPA's rationale using industry experience, the following emissions compliance options for each air oxidation unit were proposed: (1) use of a combustion device which reduces total organic compound emissions (minus methane and ethane) by 98 weight percent or to 20 ppm (by volume) or (2) maintain a total resource effectiveness (TRE) value greater than 2.2.

Subpart LLL: Standards of Performance for SO_2 Emissions From Onshore Natural Gas Processing.[51]

On January 20, 1984, EPA proposed SO_2 emission limits for new, modified, and reconstructed sweeting and sulfur recovery units in the natural gas production industry. EPA selected the proposed emission limits based upon: (1) the control systems selected as BDT for different plant

[50] 48 Fed. Reg., 48,932 (October 21, 1983).
[51] 49 Fed. Reg., 2,656 (January 20, 1984).

types depending on the H_2S/CO_2 ratio and the sulfur feed rate, (2) the design efficiencies of the available control technologies from the engineering studies, (3) technical information/data on catalyst degradation, and (4) emission source test data from facilities with demonstrated sulfur recovery technologies.

Subpart NNN: Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations.[52]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated December 30, 1983, EPA proposed VOC emission standards for new, modified, and reconstructed synthetic organic chemical manufacturing (SOCMI) distillation facilities.

Based upon industry experience and operating histories, EPA determined four combustion devices (i.e., incinerators, boilers, process heaters, and flares) able to achieve 98 percent control or 20 ppmv VOC in the outlet gas. Thus, EPA used these four devices as best demonstrated technology (BDT) for this source category. No emissions test data was provided in the proposed rule, and hence the emission standard was derived from industry experience, provided that the combustion temperature of the combustion device and the vent stream flow rate were properly maintained at the proper level and/or within the prescribed range of operation.

Based upon EPA's rationale using industry experience, EPA proposed the following emissions compliance options for each distillation vent stream: (1) use of a combustion device which reduces total organic compound emissions (minus methane and ethane) by 98 weight percent or to 20 ppm (by volume), (2) use of a flare, or (3) maintain a total resource effectiveness (TRE) value greater than 1.0.

Subpart OOO: Standards of Performance for Nonmetallic Mineral Processing Plants.[53]

On November April 22, 2008, EPA proposed to amend the standards of performance for nonmetallic mineral processing plants (NMPPs). The primary amendments for existing units dealt with testing, notification and monitoring requirements. The PM emissions limit for existing facilities remained unchanged. However, EPA proposed amendments to reduce the emissions limits for future NMPPs.

For the determination of the new PM emissions limit, EPA reviewed over 300 PM stack tests from 1990 and later for a variety of subpart OOO affected facilities and industries. Ninety-one percent of the PM stack test results achieved the proposed limit. Since some of the test results did not meet the proposed limit, but met the current NSPS limit, EPA decided not to amend the emission limit for existing facilities. The newly proposed emission limit would only apply to future affected facilities.

[52] 48 Fed. Reg., 57,538 (December 30, 1983).
[53] 73 Fed. Reg., 21,559 (April 22, 2008).

Subpart PPP: Standards of Performance for Wool Fiberglass Insulation Manufacturing.[54]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated February 7, 1984, EPA proposed PM emission standards for new, modified, and reconstructed wool fiberglass insulation manufacturing lines utilizing the rotary spin forming process.

Emission tests were conducted on nine rotary spin manufacturing lines at six plants. EPA considered data from six tests on four lines in the selection of the numerical emission limit. Tests were performed during the production of R-11 building insulation, R-19 building insulation, ductboard, and heavy density insulation. These products were identified by the industry as those that would reflect the range of emissions likely to be generated by wool fiberglass manufacturing operations.

The average total line particulate emission levels at Line A (wet ESP outlet plus uncontrolled cooling emissions) ranged from 3.4 to 4.9 kg/Mg (6.8 to 9.9 lb/ton) of glass pulled for the products tested. The average emission levels by product were 3.4 kg/Mg (6.8 lb/ton) for R-11 building insulation, 4.0 kg/Mg (8.1 lb/ton) for R-19 building insulation, and 4.9 kg/Mg (9.9 lb/ton) for ductboard. The average particulate emission level at Line B for forming and curing emissions was 2.0 kg/Mg (4.0 lb/ton) of glass pulled. The average total line particulate emission level at Line D was 1.6 kg/Mg (3.2 lb/ton) of glass pulled. The average total line particulate emission level at Line L was 1.2 kg/Mg (2.5 lb/ton) of glass pulled.

EPA's proposed numerical emission limit of 5.5 kg/Mg (11.0 lb/ton) is based on the emission levels measured at Line A. The controlled emissions from this line, which has a wet ESP on the forming and curing sections and no control of cooling emissions, ranged from 4.7 to 5.1 kg/Mg (9.4 to 10.3 lb/ton) and averaged 4.9 kg/Mg (9.9 lb/ton) of glass pulled during the production of ductboard insulation. Although compliance with an emission limit is determined using the average of the individual test runs, the highest single test run at Line A was considered when selecting the proposed emission limit to ensure that the standard would be achievable under all normal operating conditions.

The test data for Lines B, D, and L show that emissions can be reduced significantly below the proposed limit of 5.5 kg/Mg (11.0 lb/ton) on lines where process modifications are used. However, these modifications are not available to all firms in the industry. Therefore, EPA did not select a more stringent emission limit based on the use of process modifications as a control technology. Based upon the available test data and EPA's analysis, the Agency proposed a PM limit of 5.5 kg/Mg (11.0 lb/ton) of molten glass used to manufacture the product.

[54] 49 Fed. Reg., 4,590 (February 7, 1984).

Subpart QQQ: Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.[55]

According to the section *"Supplementary Information: Rationale"* contained in the preamble to the proposed rule dated May 4, 1987, EPA proposed revised VOC emission standards for new, modified, and reconstructed refinery wastewater systems.

For process drain systems, water seal controls were selected as the basis of the proposed standard. The equipment that is required by the proposed standards would be effective in reducing emissions only if proper maintenance procedures are followed. For safety reasons, junction boxes may include an open vent pipe to relieve the buildup of vapors.

Fixed roofs with captured VOC vented through a closed vent system to a control device were selected as the basis of the proposed standard for oil-water separators with a design capacity to treat more than 15.8 liters per second (250 GPM). Fixed roofs "alone" were selected as the basis of the proposed standard for oil-water separators with a design capacity of less than 250 GPM. Floating roofs with a liquid-mounted primary seal and a secondary seal were selected as an equivalent alternative technology for any size oil-water separator. Fixed roofs shall be installed over the separator in a manner so as to have a tight seal between the separator walls and the roof. Tightly sealing the roof to the separator walls will reduce VOC emissions by limiting the effects of evaporation, wind, and solar radiation. The spaces between roof sections also must be gasketed and tightly sealed. If the fixed roof has access doors or hatches, these doors and hatches shall be completely sealed and kept closed at all times during operation of the separator except during inspections and maintenance. Slop oil skimmed from the wastewater surface shall be collected and reused or disposed of in an enclosed system to limit VOC emissions.

Fixed roofs are the basis of the proposed standard for dissolved air flotation systems (DAFs). For DAF systems, a fixed roof must be installed over the flotation tank. The roof will reduce VOC emissions by limiting the effects of evaporation, wind, and solar radiation. A pressure control valve may be provided in the roof to relieve the periodic positive pressure which will build up in the vapor space due to the flotation process. The basis of the proposed standard for IAF systems is an operational standard requiring IAF systems with design capacities to treat more than 250 GPM to be maintained gas-tight.

Based upon the industry experience, technical literature, and EPA's rationale, the proposed standards would limit VOC emissions from petroleum refinery wastewater systems as follows: (1) for process drain systems, water seal controls must be installed on drains, (2) for oil-water separators with a design capacity to treat more than 15.8 liters per second (250 GPM), a fixed roof and closed vent system which directs vapors to a control device must be installed that has a destruction efficiency of 95 percent or greater, (3) for DAF air flotation systems, a fixed roof must be installed, and (4) for IAF systems with a design capacity to treat more than 15.8 liters per second (250 GPM), the unit must be operated in a gas-tight condition since it is already equipped with a fixed roof.

[55]52 Fed. Reg., 16,334 (May 4, 1987).

Subpart RRR: Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes.[56]

According to the Section IV *"Rationale for the Proposed Standards"* contained in the preamble to the proposed rule dated June 29, 1990, EPA proposed VOC emission standards for new, modified, and reconstructed synthetic organic chemical manufacturing (SOCMI) reactor process facilities.

Based upon industry experience and operating histories, 2 combustion devices (i.e., incinerators and flares) were deemed able to achieve 98 percent control or 20 ppmv VOC in the outlet gas. Thus, these 2 devices were candidates for BDT for this particular source category. No emissions test data was provided in the proposed rule, and hence the emission standard was derived from industry experience, provided that the combustion temperature of the combustion device and the vent stream flow rate were properly maintained at the proper level and/or within the prescribed range of operation. Based upon EPA's rationale using industry experience, the following emissions compliance options for each reactor process were proposed: (1) use of a combustion device which reduces total organic compound emissions (minus methane and ethane) by 98 weight percent or to 20 ppm (by volume) or (2) maintain a total resource effectiveness (TRE) value greater than 1.0.

Subpart SSS: Standards of Performance for Magnetic Tape Manufacturing Industry.[57]

According to the Section IV *"Rationale for the Proposed Standards"* contained in the preamble to the proposed rule dated January 22, 1986, EPA proposed VOC emission standards for new, modified, and reconstructed magnetic tape manufacturing lines were developed.

For coating operations, EPA determined that the best demonstrated technology (BDT) is the use of a total enclosure on the coating application/flash-off area and the venting of these captured emissions and the oven emissions to a control device. The format for the proposed standard would require control of a fixed portion of the total emissions from the coating operation. The required emission reduction of 93 percent was selected based on information obtained from manufacturers of magnetic tape and emission test data from other similar web-coating operations. Because the coating operation includes both the application/flash-off area and the oven, a single level of control for the coating operation does not distinguish where the emissions originate within the operation. The overall control efficiency is dependent upon both the capture efficiency of the total enclosure and the efficiency of the control device.

There are nine plants in this industry operating with total enclosures. Maintenance of a negative pressure in the enclosure can theoretically result in 100 percent capture if the resulting face velocities across any openings are sufficient. Because face velocities may not be maintained when doors or other forms of access are open, actual capture efficiencies may be somewhat reduced from the theoretical value of 100 percent. There is also a potential for fugitive emissions from the oven if similar openings exist.

[56] 55 Fed. Reg., 26,953 (June 29, 1990).
[57] 51 Fed. Reg., 2,996 (January 22, 1986).

Extensive emission test data document the performance of carbon adsorbers as a control device. Numerous tests in web-coating and other industries have demonstrated that carbon adsorbers can consistently achieve 95 percent control. In the magnetic tape industry, data are available on the performance of four carbon adsorbers. In monthly liquid material balances for a 1-year period at two magnetic tape plants and during emission test measurements at two other magnetic tape plants, carbon adsorbers achieved efficiencies that ranged from 95 to 99 percent. As previously discussed, the overall control efficiency is the product of capture and control. Assuming the theoretical capture efficiency of 100 percent, the equipment selected as BDT would be able to reduce VOC emissions from the coating operation by at least 95 percent and possibly as much as 99 percent. These theoretical overall control efficiencies may not be achievable because of fugitive emissions from the enclosure or the oven.

Data on which to select actual control efficiency are available for four magnetic tape plants. Representative samples from two magnetic tape plants that are equipped with total enclosures and carbon adsorbers have stated that efficiencies of 95 percent are achievable. The EPA evaluation of the capture and control system selected as BDT agrees with these statements. Because these are the highest overall control efficiencies reported or measured, EPA determined that the level of the standard should be no higher than 95 percent.

A representative sample from a plant that was not equipped with a total enclosure and, thus, only controlled emissions from the oven with a carbon adsorber, has stated that this level of control achieves 92 percent reduction in VOC emissions. This reduction is substantiated by emission test data from another magnetic tape plant that also controlled only emissions from the oven but not from the application/flash-off area. This test was conducted on a coating line at which the drying oven emissions were controlled by a condensation system. The test was a 3-hour liquid solvent material balance in which the volume of solvent applied was calculated from the coating width, speed, thickness, and formulation. This test demonstrated a 93 percent recovery for the control system. If these facilities had been equipped with enclosures to also capture and, thus, reduce emissions from the application/flash-off area, higher control efficiencies may have been achieved. On this basis, EPA concluded that the level of the standard should be no lower than 92 percent.

Alternatively, the use of a coating that contains 0.20 kg of VOC/l of coating solids or less would be allowed instead of the requirement for 93 percent reduction of VOC emissions from the coating operation. (Coatings currently in use contain about 3.6 kg VOC per liter of coating solids.) This value was selected because it is the lowest solvent content at which the cost to use an add-on VOC control device is reasonable (i.e., no more than $1,200/Mg).

For coating mix preparation equipment, the proposed standard is an equipment format, rather than a numerical limit. At lines that have exceeded an annual solvent use of 38 m^3 one time (the size cutoff for the coating operation), BDT is containment of all VOC emissions with covers and ducting those emissions to a control device that is at least 95 percent efficient. No control of VOC emissions is required at lines that have never exceeded an annual solvent of 38 m^3 because mix equipment control is cost effective only if the control device for the coating operation is used to control mix equipment emissions.

For solvent storage tanks, the BDT for this source is installation of pressure relief valves with a gauge pressure setting of at least 103 kPa. Although tanks operated at these pressures are not

currently used in this industry, they are used to store solvents in the chemical industry. A higher pressure setting is desirable because it achieves a greater emission reduction than a typical fixed roof tank or a tank with a lower pressure setting. These higher pressure tanks have a different design than the tanks now in use in the magnetic tape industry. However, based on EPA analysis and on data provided by a tank design specialist, the cost to build such a tank is the same as that for a lower pressure tank. For the solvents used in this industry, there is no increased safety hazard as a result of operating storage tanks at 103 kPa. For the following reasons, the proposed standard for solvent storage tanks is the installation of pressure relief valves with a gauge pressure setting of at least 103 kPa: (a) the annual cost of the control option is reasonable (a net credit), (b) there is no increased safety risk, and (c) there is increased emission reduction. The size cutoff discussed for the coating operation and associated mix equipment would not apply to solvent storage tanks because the cost effectiveness of controlling VOC emissions from tanks is independent of line size.

There are 3 VOC emission sources in a magnetic tape coating line, which are (1) the coating area, consisting of an application/flash-off area and a drying oven, (2) equipment for preparing the coating, and (3) solvent storage tanks. Based upon the available test data, industry experience, technical literature, and EPA's rationale, the proposed standards would limit VOC emissions from coating operations using greater than 38 m^3 of solvent to either 93 percent control device efficiency or 0.20 kg VOC/liter of coating solids. In addition, the mix equipment from coating operations using greater than 38 m^3 of solvent would require ventilation to a 95 percent efficient control device. All new solvent storage tanks with a capacity of less than 75 m^3 would also require pressure relief valves set at a minimum 103 kPa gauge pressure.

Subpart TTT: Standards of Performance for Industrial Surface Coating: Plastic Parts for Business Machines.[58]

According to the Section IV *"Rationale for the Proposed Standards"* contained in the preamble to the proposed rule dated January 8, 1986, VOC emission standards for new, modified, and reconstructed sources that surface coat plastic parts for business machines were developed.

For exterior coating, different standards were proposed for prime and color coating, and texture and touch-up coating based on different BDTs. Different standards were developed for prime and color coating versus texture and touch-up coating because air-assisted airless spray application of prime and color coats has been demonstrated, while application of texture and touch-up coats with this equipment has not. The BDT for all exterior coating processes (except fog coating) is based on using organic solvent-based coatings containing 60 percent solids and 0.58 kg VOC/liter of coating solids, as applied. The BDT for prime and color coating is the application of these coatings at 40 percent TE with air-assisted airless or electrostatic spray equipment. Therefore, the numerical emission limit for prime and color coats is 1.5 kg VOC/liter of solids applied. Based upon industry experience, technical literature, and EPA's rationale, the proposed standards would limit VOC emissions for exterior coating to no more than 1.5 kg VOC/liter of coating solids applied for prime and color coats.

[58]51 Fed. Reg., 854 (January 8, 1986).

Subpart UUU: Standards of Performance for Calciners and Dryers in Mineral Industries.[59]

According to the Section IV *"Rationale for the Proposed Standards"* contained in the preamble to the proposed rule dated April 23, 1986, EPA proposed PM emission standards for new, modified, and reconstructed calciners and dryers at mineral processing plants.

Data gathered during emission tests on fabric filters used to control emissions from a variety of calciners and dryers indicate that variations in the size distribution of PM and the mineral processed do not typically affect fabric filter performance. Other collection devices used in mineral industries include dry ESPs and wet scrubbers. Dry ESPs are used only in the alumina, bentonite, gypsum, lightweight aggregate, and magnesium compounds industries. Data obtained from EPA-conducted tests or from State compliance tests approved by EPA show that, in some instances, controlled PM emission levels from calciners and dryers at existing facilities are significantly lower than the mass emission limits stipulated by the appropriate SIP regulations. Therefore, the same control technology that is used at existing facilities could also be used at affected facilities to achieve the NSPS. However, in many cases, facilities subject to the NSPS would have to perform control device maintenance more frequently than is typical at existing plants or modify control device operating parameters from those at existing facilities to ensure compliance with the NSPS. By requiring better operation and maintenance procedures, the NSPS would reduce the deterioration in performance of new source control devices to the SIP levels or to the allowable State opacity limits.

As discussed below, the results of emission tests and scrubber performance modeling indicate that an emission control level for calciners of 0.09 g/dscm (0.04 gr/dscf) and an emission control level for dryers of 0.057 g/dscm (0.025 gr/dscf) could be achieved by all affected facilities in all of the 17 mineral industries. Emission test data from 52 source tests comprise the data base. Of the 52 tests, 25 were conducted on dryers. These data show that all ESP- and fabric filter-controlled dryers can achieve the emission level of 0.057 g/dscm (0.025 gr/dscf) during normal operation. Tests of 15 wet scrubber-controlled dryers in 7industries indicate that for 10 of the 15dryers, relatively low-energy wet scrubbers (3- to 10-in. H_2Opressuredrop) were able to reduce emissions to less than the above referenced emissions control level. The emissions for all 15 dryers averaged 0.04 g/dscm (0.02 gr/dscf) and never exceeded 0.09 g/dscm (0.04 gr/dscf).Of the 52 source tests comprising the data base, 27 tests were conducted on calciners. These data show that all ESP and fabric filter-controlled calciners can achieve the emission level of 0.09 g/dscm (0.04 gr/dscf) during normal operation. Of the 27 tests, 9 tests were conducted on wet scrubber controlled calciners in 5 industries. Of the nine tests, six of the calciners had emissions at or below the above referenced emission control level. The concentration of PM emissions from these units averaged 0.09 g/dscm (0.04gr/dscf) and never exceeded 0.17 g/dscm (0.08 gr/dscf).Test data for ESP-controlled process units were obtained for a bentonite dryer, two alumina calciners, and two magnesium compound calciners. Emissions from the dryer were 0.014 g/dscm (0.006 gr/dscf), and emissions from the calciners ranged from 0.037 to 0.056 g/dscm (0.016to 0.025 gr/dscf). There were19 process unit combinations where no emission data were obtained.

[59]51 Fed. Reg., 15,438 (April 23, 1986).

Based upon the available test data and EPA's rationale, the Agency proposed the following PM limits: (1) 0.09 g/dscm (0.04 gr/dscf) from calciners and (2) 0.057 g/dscm (0.025 gr/dscf) from dryers. In addition, stack emissions would also be limited to 10 percent opacity for process units controlled with dry control devices. The visible emissions standard does not apply to facilities that use wet scrubbers to control emissions.

Subpart VVV: Standards of Performance for Polymeric Coating of Supporting Substrates.[60]

According to the Section IV *"Rationale for the Proposed Standards"* contained in the preamble to the proposed rule dated April 30, 1987, EPA proposed VOC emission standards for new, modified, and reconstructed sources that perform polymeric coating of supporting substrates.

According to EPA, the best demonstrated technology (BDT) for the coating operation is the use of a total enclosure on the coating application/flash-off area and the venting of these captured emissions and the oven emissions to a control device. The format for the proposed standard would require control of a fixed portion of the total emissions from the coating operation. EPA selected 93 percent reduction of VOC emitted as the value for the proposed standard for the coating operation. The overall efficiency of a control system is the product of two components, capture and control. If the capture efficiency is perfect (i.e., 100 percent) and the emissions are directed to an acceptable carbon adsorber, the overall emission reduction would be no less than 95 percent. Thus, 95 percent control is the maximum control that could be required.

A performance test to determine capture efficiency of the total enclosure and overall control efficiency of the coating operation was conducted at a polymeric coating plant. The determination of either overall control efficiency or the capture efficiency of the enclosure were precluded by fugitive VOC emissions within the building that were drawn into the enclosure and test methodologies that were subsequently judged to be inadequate for measuring some liquid streams. For this reason, data on the performance of partial and total enclosures in similar web-coating industries were used to select the actual proposed control efficiency for this NSPS.

Plants in the flexible vinyl coating and printing industry (FVCP) and the publication rotogravure industry are similar to polymeric coating plants in that solvent-borne coatings are applied to a continuous web of supporting material. The solvent content (by volume) contained in typical coatings used in the FVCP and rotogravure industries is within the range of coating formulations used in polymeric coating facilities. The VOC capture and control systems are very similar to those used in polymeric coating. Fixed-bed carbon adsorbers are common control devices in all three industries. An FVCP print line with partial capture of fugitive coater emissions by a hood within the print room achieved short-term (less than 2 hours) capture efficiencies of 90 to 94 percent based on gas material balances. Combined with a carbon adsorber efficiency of 95 percent, total control efficiencies of 86 to 90 percent were achieved.

Two publication rotogravure presses, each with a cabin-like structure around the top third of the presses to capture fugitive emissions (equivalent to a partial enclosure) achieved short-term (9-hour and 52-hour) liquid material balance control efficiencies of 89 to 92 percent. Based on

[60]52 Fed. Reg., 15,906 (April 30, 1987).

these data, the use of a partial enclosure and carbon adsorber can achieve overall control efficiencies up to 92 percent. The use of a total enclosure and carbon adsorber (BDT level of control) should be able to achieve a higher level of control because of the greater fugitive emission capture efficiency of a total enclosure.

In the pressure sensitive tape and label (PSTL) industry, solvent-borne coatings are also applied to a continuous web of supporting material with VOC capture and control systems very similar to those used at polymeric coating facilities. The solvent content (by volume) of typical coatings used in the PSTL industry is within the range of coatings applied at polymeric coating plants. The same types of coating applicators and drying ovens are used at both PSTL and polymeric coating plants. Fixed-bed carbon adsorbers are also common at both types of plants. At one PSTL plant, the building in which the four coating-lines are located is sealed tight enough to allow a slight negative pressure in the work area relative to the outdoors. The drying ovens operate at a slight negative pressure relative to the room and the oven makeup air is pulled directly from the coater work area. There are also hoods that are located over the coaters and are vented to the drying ovens. This is a fully enclosed, tight system in which air flows from outdoors into the building, into the oven, and then to a fixed-bed carbon adsorber. The company produces a wide variety of products; and coating operations are typified by short production runs and low VOC concentrations, which are also typical of polymeric coating lines. These operating conditions make this PSTL plant a difficult control situation. However, the facility demonstrated a 4-week overall VOC emission reduction of 93 percent based on a liquid material balance. On this basis, EPA determined that an emission reduction of 93 percent is achievable by BDT controls. The highest level of control considered for the proposed coating operation standard was 95 percent, based on a theoretical total enclosure capture efficiency of 100 percent and a control device efficiency of 95 percent based on a carbon adsorber (BDT level of control). However, the PSTL test data indicate that 95 percent control may not be achievable with BDT controls under all circumstances. Therefore, 95 percent was rejected as the level of the standard. The use of a partial enclosure and carbon adsorber achieved control efficiencies up to 92 percent, indicating that the BDT level of control should be higher than 92 percent. The PSTL data demonstrate that a level of 93 percent control is achievable by BDT. Therefore, because 93 percent control is the highest level of control that would still ensure achievability, the proposed standards would require this level of control for the coating operation. In addition, low-solvent coatings can be used to meet the standard by keeping annual solvent consumption below the 110 m^3/year limit.

The proposed standard for coating mix preparation equipment is an equipment standard. Depending on solvent utilization, the BDT for this equipment is the use of covers to contain all VOC emissions and the ducting of those emissions to a control device that is at least 95 percent efficient or the installation and use of covers equipped with conservation vents. No control of VOC emissions from coating mix preparation equipment is required at lines below the annual solvent use cutoff, because mix equipment control is not cost effective if a separate control device is used to control mix equipment emissions.

Based upon industry experience, technical literature, and EPA's rationale, the proposed standard would require the installation of covers on on-site coating mix preparation equipment and ductwork to vent all emissions to a control device that is at least 95 percent efficient on all coating lines with a solvent utilization of at least 150 m^3/year. Coating lines with a solvent

utilization of at least 110 m^3/year, but less than 150 m^3/year, shall install and use vapor-tight covers equipped with conservation vents on each piece of coating mix preparation equipment rather than controlling emissions with a 95 percent efficient control device. Each cover must be in place at all times except during addition and withdrawal of ingredients or visual inspection. The covers shall be equipped with conservation vents set at 17.2 kilopascals (kPa). Those lines that use less than 110 m^3 of solvent per year would require no control of coating mix preparation equipment.

Subpart WWW: Standards of Performance for Municipal Solid Waste Landfills.[61]

On May 30, 1991, EPA proposed new standards of performance for municipal solid waste (MSW) landfills. The proposed standards implement the requirements in section 111(b) of the Clean Air Act (CAA) which requires sources to control emissions to the level achievable by the "best demonstrated technology" (BDT).

EPA developed a database to study the impacts of applying different control technologies to new and existing landfills. In 1986, EPA sent municipal landfill survey questionnaires to 1,250 of the estimated 6,034 active MSW landfills in the United States. From this survey, EPA received responses for a total of 1,174 active MSW landfills. Of the 1,174 landfills responding, the information provided on location, annual waste acceptance rate, refuse in place, age, depth, and design capacity were complete for 931 landfills. However, site-specific emission rates were not known and, therefore, were not reported to EPA. Because EPA needed detailed emission rate information, gas generation rate and nonmethane organic compound (NMOCs) concentration information from literature, State and local air pollution control agencies, and industry test reports were obtained through the authority of section 114 of the CAA. From the data gathered under the information collection request (ICR), EPA established BDT and emission reduction rates for MSW landfills.

Subpart AAAA: Standards of Performance for New Small Municipal Waste Combustion Units.[62]

On August 30, 1999, EPA proposed to reestablish new source performance standards (NSPS) for new small municipal waste combustion (MWC) units. The NSPS for small MWC units were originally promulgated on December 19, 1995, but were vacated by the U.S. Court of Appeals for the District of Columbia Circuit in March 1997. However, this proposed NSPS are functionally equivalent to the 1995 NSPS.

From the technical basis of standards and guidelines section of the December 1995 NSPS, EPA considered the following types of data: (1) Over 100 MWC plant-specific questionnaires; (2) emissions information from literature, and State and local agencies; and (3) EPA and industry test reports. Overall, the EPA used performance test data from over 60 MWC plants to develop the standards and guidelines.

[61] 56 Fed. Reg., 24468 (May 30, 1991).
[62] 64 Fed. Reg., 47,276 (August 30, 1999).

Subpart CCCC: Standards of Performance for Commercial and Industrial Solid Waste Incineration Units.[63]

On December 1, 2000, EPA issued the Agency initial NSPS for commercial and industrial solid waste incineration (CISWI) units. In 2001, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) granted EPA's voluntary remand, without vacatur of the 2000 regulations. In 2005, EPA proposed and finalized the CISWI definition rule which revised the definition of "solid waste,' "commercial and industrial waste," and "commercial and industrial waste incineration units." In 2007, the D.C. Circuit vacated and remanded the 2005 CISWI definition rule. On June 4, 2010 EPA proposed its response to the vacatur of the definition rule and the five-year technology review of the new source performance standards. The emission standards for new CISWI units were based on a large amount of stack testing data collected pursuant to Information Collection Request No 2,286.03.

Subpart EEEE: Standards of Performance for Other Solid Waste Incineration Units.[64]

On December 9, 2004, EPA proposed new source performance standards for other solid waste incinerator (OSWI) units. Section 129 of the CAA, titled, Solid Waste Combustion, requires EPA to develop and adopt NSPS and emission guidelines for solid waste incineration units that reflects the maximum achievable control technology (MACT).

For this proposed rule, EPA determined the new source MACT floors and MACT separately for the two subcategories of OSWI -- the very small municipal waste combustion (VSMWC) units and institutional waste incineration (IWI) units.

Although EPA did not have emission test data for any of the units in the OSWI inventory, emissions information was available for other incineration units that EPA concluded were similar. Accordingly, emission levels for the MACT floor level of control were determined by using actual emissions test data from these "similar" units in other source categories. This approach was used for establishing the numerical emission limits for both subcategories.

Subpart JJJJ: Standards of Performance for Stationary Spark Ignition and Reciprocating Internal Combustion Engines.[65]

On June 12, 2006, EPA proposed new source standards of performance for stationary spark ignition (SI) internal combustion engines (ICE). New source performance standards for stationary SI engines are issued under section 111(b) of the CAA. New source performance standards require these sources to control emissions to the level achievable by best demonstrated technology (BDT), considering costs and any non-air quality health and environmental impacts and energy requirements. For BDT determinations, EPA separated stationary SI engines into different output categories. Subsequently BDT determinations, and thus emission limits, were proposed for each of the output based categories.

[63] 75 Fed. Reg., 31,942 (June 10, 2010).
[64] 69 Fed. Reg., 71,472 (December 9, 2004).
[65] 71 Fed. Reg., 33,804 (June 12, 2006).

For stationary SI engines capable of producing $\leq$ 25HP, it was concluded that BDT were the same as the technologies that were the basis for the nonroad SI engine Phase 2 standards in this size range. As a result, stationary SI engines in this size range were required to be certified to the same emission standards as nonroad SI engines as specified in 40 CFR 90. Similarly, for stationary SI gasoline engines and rich burn liquefied petroleum gas (LPG) engines capable of producing $\geq$ 25HP, it was concluded that BDT were the same as the technologies that were the basis for the nonroad SI engine Tier 2 standards in this size range. As a result, stationary SI engines in this size range were required to be certified to the same emission standards as nonroad SI engines as specified in 40 CFR 1048.

Emission limits for another classification of SI engines were also proposed: Stationary non-emergency SI natural gas engines 25<HP<500 and SI lean burn LPG engines 25<HP<500. For stationary non-emergency SI natural gas and lean burn LPG engines between 25 and 500 HP, EPA concluded that emissions from these engines can be different than nonroad SI engines in the same size range, and that more stringent standards are possible for these engines. Therefore, EPA evaluated currently available control technologies to reduce criteria pollutant emissions from these stationary SI engines. However, EPA proposed allowing manufacturers to certify any SI natural gas or lean burn LPG engines between 25 and 50 HP to the standards for nonroad engines in this power range in 40 CFR part 1048 as an alternative to the standards being proposed in the SI NSPS (In essence, this simply expanded the previous classification to include SI engines < 50HP). EPA concluded that engines between 25 and 50 HP can be similar to nonroad engines in this size range and, therefore, feels it is appropriate to provide engine manufacturers with the option to certify these engines to 40 CFR Part 1048. However, for engines greater than 50 HP, EPA did not include this option. For the rest of this classification, EPA determined BDT to be nonselective catalytic reduction (NSCR) and that NSCR is essentially the same technology as a three-way catalyst. This was based on the emission standards set for hazardous air pollutants (HAP) for reciprocating internal combustion engines (RICE) greater than 500HP. EPA concluded that the emission standards that were achievable for these larger engines could be achieved by smaller SI engines if equipped with NSCR. EPA collected information from engine manufacturers to establish the emission limits.

For stationary non-emergency natural gas engines and lean burn LPG engines greater than 500HP, EPA also determined BDT to be NSCR for similar reasons as previously discussed. Likewise, the emission limits were set at the same levels with similar justification from manufacturers' information. EPA determined that emissions from stationary SI landfill and digester engines are similar to that of new lean burn engines. As a result, EPA adopted a similar performance standard approach for stationary SI landfill and digester engines. However, the proposed standards were slightly looser due to the variability in the quality of the fuel being burned. For stationary emergency SI engines, the same approach and limits were set as for new lean burn engines. The only difference was the effective date to allow a longer lead time for emergency engines to comply with the standard.

Subpart KKKK: Standards of Performance for Combustion Turbines.[66]

On February 21, 2014, EPA proposed standards of performance for new stationary combustion turbines as Subpart KKKK. The proposed new standards reflected changes in NO_X emission control technologies and turbine design since standards for these units were originally a level that brings the emission limits up to date with the performance of current combustion turbines and their emissions.

To determine the proposed NO_X emission limits, EPA evaluated stack test data for stationary combustion turbines of different sizes. The data provided EPA with information on actual NO_X emissions performance in relation to the size of the unit and the type of fuel being used. In addition, EPA obtained information from turbine manufacturers on the NO_X levels that they guarantee for their new stationary combustion turbines. EPA primarily used these manufacturer guarantees to confirm the NO_X levels observed in the stack test data. EPA considered requiring the use of SCR in setting the limit for NO_X. However, EPA determined that the costs for SCR were high compared to the incremental difference in emission concentration. EPA learned that newer large turbines without add-on controls could readily achieve 9 or 10 parts per million (ppm). Use of SCR might bring this level down to 2 to 4 ppm. However, SCR could be difficult to implement for turbines operating under variable loads. EPA determined that the incremental benefit in emissions reductions did not justify the costs and technical challenges associated with the addition and operation of SCR. Therefore, EPA elected to not base the NO_X emission limit on this (SCR) add-on control.

Subpart LLLL: Standards of Performance for New Sewage Sludge Incineration Units.[67]

On October 14, 2010, EPA proposed new source performance standards and emission guidelines for sewage sludge incineration (SSI) units. Following a significant history of litigation, EPA finally proposed these limits under section 129 of the CAA. Section 129 (a)(2) of the CAA requires that EPA determine the emissions control that is achieved in practice by the best-controlled similar unit when establishing the MACT floor for new units, and the average emission limitation achieved by the best performing 12 percent of units when establishing the MACT floor for existing units. *Note: this is a fundamentally different construct than that of the requirements found in section 111 of the CAA, which makes use of BDT or BSER.*

Under CAA section 129(a)(2), MACT for new sources shall be no less stringent than the emission control achieved in practice by the best controlled similar unit. In other words, the best performing unit was identified by ranking the units from lowest to highest for each subcategory and pollutant and selecting the unit with the lowest 3-run test average emissions test data for each pollutant, with an appropriate accounting of emissions variability.

EPA collected surveys from 9 municipalities and collected data from 16 units that were in operation (11 multiple hearth [MH] incinerators and 5 fluidized bed [FB] incinerators). The surveyed information was supplemented with emissions test information for 9 MH SSI units collected from State environmental agencies public databases. In total, emissions information

[66] 70 Fed. Reg., 8,314 (February 18, 2005).
[67] 75 Fed. Reg., 63,260 (October 14, 2010).

was collected from 5 FB incinerators and 20 MH incinerators from facilities responding to the ICR and additional test reports provided by State environmental agencies.

Subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.[68]

On August 23, 2011, EPA proposed to address the reviews of the new source performance standards for Volatile Organic Compounds (VOCs) and sulfur dioxide emissions at natural gas processing plants. No substantive changes to the current NSPS were proposed. However, additional VOC standards were proposed to cover additional processes at oil and natural gas operations. These included gas well completions, pneumatic controllers, compressors, and storage vessels.

For VOC emissions for well completions, two sub-categories of fracturing gas wells were established. For both sub-categories it was determined that the VOC emissions could not feasibly be measured. As a result, VOC reduction cannot be quantified and numerical performance standards for VOC emissions were not set.

For VOC emissions for pneumatic controllers, the BSER was determined as non-gas driven controllers. Since the non-gas driven controllers use instrument grade or compressed air for operation instead of pressurized natural gas, any leaks from these types of controllers would yield zero VOC emissions. As a result, the proposed standard for pneumatic controllers at gas processing plants was set at zero VOC emissions.
For VOC emission for compressors, two sub-categories were established, centrifugal and reciprocating. For centrifugal compressors BSER was determined as dry seal system based on manufacturing literature which indicated lower leak rates for this type of seal configuration than that of the wet seal based compressors. The lower the leak rate of natural gas, the lower the VOC emissions. However, since the leak rates from either type cannot be accurately measured, the amount of VOC reduction cannot be quantified. As a result, numerical standards were not set. Because VOC emissions from reciprocating compressors are fugitive emissions, there are no devices available to capture and control those emissions. As a result, only operational standards were proposed.

[68] 76 Fed. Reg., 52,738 (August 23, 2011).

Table 1. Type of Information Used to Support Proposed NSPS Emission Limits

Subpart	Standard of Performance for:	Achieved by Existing Sources in Category	Emissions Data	Permit Review	Technical Literature	State Rules
D	Fossil-Fuel-Fired Steam Generators	X	X			
Da	Electric Utility Steam Generating Units	X	X			
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X		
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X		
Eb	Large Municipal Waste Combustors	X	X			
Ec	Hospital/Medical Infectious Waste Incinerators	X	X			
F	Portland Cement Plants	X	X			
Ga	Nitric Acid Plants	X	X			
I	Hot Mix Asphalt Facilities	X	X			
J	Petroleum Refineries	X	X		X	
Ja	Petroleum Refineries	X	X		X	X
K	Storage Vessels for Petroleum Liquids	X	X		X	
Ka	Volatile Organic Liquid Storage Vessels	X	X		X	
L	Secondary Lead Smelters	X	X		X	
M	Secondary Brass and Bronze Ingot Production Plants	X	X		X	
N	Iron and Steel Plants	X	X		X	
Na	Basic Oxygen Process Steel Making Secondary Emissions	X	X			
O	Sewage Treatment Plants	X	X		X	
P	Primary Copper Smelters	X	X		X	
Q	Primary Zinc Smelters	X	X		X	
R	Primary Lead Smelters	X	X		X	
S	Primary Aluminum Reduction Plants	X	X		X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage	X	X		X	
Y	Coal Preparation Plants	X	X	X		
Z	Ferroalloy Production Facilities	X	X		X	
AA	Steel Plants: Electric Arc Furnaces	X	X	X		

Table 1. Type of Information Used to Support Proposed NSPS Emission Limits

Subpart	Standard of Performance for:	Achieved by Existing Sources in Category	Emissions Data	Permit Review	Technical Literature	State Rules
BB	Kraft Pulp Mills	X	X		X	
CC	Glass Manufacturing Plants	X	X			
DD	Grain Elevators	X	X		X	
EE	Surface Coating of Metal Furniture	X			X	
GG	Stationary Gas Turbines	X	X			
HH	Lime Manufacturing Plants	X	X		X	
LL	Metallic Mineral Processing Plants	X	X	X		
MM	Automotive & Light-Duty Truck Surface Coating Operations[69]	X				
NN	Phosphate Rock Plants	X	X			
PP	Ammonium Sulfate Manufacture	X	X			
TT	Metal Coil Surface Coating	X	X			
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X		X	
VV	Equipment Leaks of VOCs from SOCMI and Petroleum Refineries[70]	X			X	X
WW	Beverage Can Surface Coating Industry	X	X		X	
XX	Bulk Gasoline Terminals	X	X			
BBB	Rubber Tire Manufacturing[71]	X			X	
DDD	Polymer Manufacturing	X	X		X	
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X		X	
HHH	Synthetic Fiber Production	X	X		X	
III	SOCMI – Air Oxidation Process Units	X	X		X	
LLL	SO2 Emissions From Onshore Natural Gas Processing	X	X		X	
NNN	SOCMI – Distillation Operations	X	X		X	
OOO	Nonmetallic Mineral Processing Plants	X	X			
PPP	Wool Fiberglass Insulation Manufacturing	X	X			
QQQ	Petroleum Refinery Wastewater Systems[72]	X			X	
RRR	SOCMI – Reactor Processes[73]	X			X	

[69] Although EPA did not have any stack testing data, the Agency did have the results of testing of the type of coatings the NSPS required. EPA relied on these data.
[70] Due to lack of feasible emissions test data, no numerical emission limits were set as a result of this action.
[71] Emission testing was not feasible. EPA relied instead on, among other things, actual industry experience in achieving the level of control; required.
[72] Emission testing was not feasible. EPA relied instead on, among other things, actual industry experience in achieving the level of control; required.

Table 1. Type of Information Used to Support Proposed NSPS Emission Limits

Subpart	Standard of Performance for:	Achieved by Existing Sources in Category	Emissions Data	Permit Review	Technical Literature	State Rules
SSS	Magnetic Tap Coating	X	X		X	
TTT	Industrial Surface Coating	X			X	
UUU	Calciners and Dryers in Mineral Industries	X	X			X
VVV	Polymeric Coating of Supporting Substrates	X	X		X	
WWW	Municipal Solid Waste Landfills	X	X		X	X
AAAA	New Small Municipal Waste Combustion Units	X	X			X
CCCC	Commercial and Institutional Solid Waste Incineration Units	X	X			
EEEE	Other Solid Waste Incineration Units (OSWI)	X	X[74]			
JJJJ	Stationary Spark Ignition and Reciprocating Internal Combustion Engines	X			X	
KKKK	Stationary Combustion Turbines	X	X			
LLLL	Sewage Sludge Incineration Units	X	X			X
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution[75]	X				

[73] Emission testing was not feasible. EPA relied instead on, among other things, actual industry experience in achieving the level of control; required.

[74] EPA did not have emissions data for the units in the OSWI category. As a result EPA used data from other incineration units that were deemed to be "similar". The test data from these "similar" sources were used to establish the MACT floor.

[75] Due to lack of feasible emissions test data, no numerical emission limits were set as a result of this action.

STATUS OF CARBON CAPTURE AND SEQUESTRATION (CCS) DEMONSTRATIONS IN RESPONSE TO PROPOSED NEW SOURCE PERFORMANCE STANDARDS FOR CO_2

Prepared for the

Utility Air Regulatory Group

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May 2, 2014

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SECTION i

SUMMARY

The U.S. Environmental Protection Agency (EPA) has proposed carbon dioxide (CO_2) limits for coal-fired power stations that require carbon capture and sequestration (CCS) technology. EPA's judgment that CCS technology is adequately demonstrated and the best system of emission reduction is based on results from pilot-scale and demonstration tests, and experience with one commercial-scale unit located in the U.S. that produces not electricity but synthetic gas and other byproduct materials.[1] In addition, EPA wrongly assumes storing CO_2 in depleted oil reservoirs – supporting enhanced oil recovery (EOR) – can be broadly generalized nationwide.

Meaningful experience is absent with the three evolving CO_2 control options – postcombustion control, precombustion control, and oxycombustion – as well as CO_2 sequestration. The CO_2 control options have been tested at pilot plant and demonstration-scale, but there are no integrated processes that operate dedicated to electric power generation. Although claims abound of experience, most are of limited relevance. For example, the CCS Institute in its *Global Status of CCS: February 2014* notes twelve projects in operation world-wide, but none generate electricity for sale to the grid.[2] Instead, these projects strip CO_2 for gas processing or to produce chemicals, fertilizer or synthetic gas. In addition to treating gas of different composition, many of the units use equipment that is a small fraction of the size required for power generation.

Additional experience is required to assess CCS commercial feasibility, and to design commercial-scale units for most coals at almost any domestic U.S. site. To broadly deploy CO_2 capture three challenges must be met. First, results must be scaled from pilot plants and early demonstration units to a commercial size unit, typically 500 MW or more. Second, results must be generalized for broad application, which means applying lessons learned with one type of fuel at one site, to numerous fuels and sites nationally. Third, it must be assured that components work not only individually but reliably in a system at large scale, while meeting a variable load.

There is no shortcut to acquire this knowledge: demonstration and early commercial units must be financed, built, and tested for several years. At present only two test units will operate in North America by the end of 2014. About seven additional demonstrations are planned – including several in Europe – but financing for these additional projects is not complete, leaving these projects at risk.

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[1] As to be discussed in Section 5, EPA cites experience with the Great Plains Synfuels Project as justifying the feasibility of pre-combustion carbon capture for utility power generation. This unit actually produces synthetic natural gas for pipeline delivery and does not deliver wholesale power to the grid.

[2] *The Global Status of CCS: February 2014,* Global CCS Institute, page 3. See also the Global CCS Institute's *The Global Status of CCS: 2013*; Table A.3. on page 162 for specific projects.

CO_2 once captured must be safely sequestered or reused. Most of the proposed demonstrations or early commercial units plan to reuse CO_2 for EOR, which has a long history in the U.S. in oil and gas fields located in states such as Texas. But assuming broad CCS application based on EOR restricts plant location and does not eliminate uncertainty. EOR sites are relatively limited. Absent EOR, the most prominent fate of CO_2 is sequestration within deep saline reservoirs. The capacity to store CO_2 in deep saline reservoirs, although better distributed across the U.S. than EOR, still presents an uneven sink across all states.

Other challenges exist for both EOR and deep saline reservoirs. Characterization of subsurface formations is not complete. Broad use of both EOR and deep saline reservoirs require investment in infrastructure for pipeline delivery, and clarifying laws defining property rights.

It is possible CCS can be commercially demonstrated as a viable means to reduce CO_2 emissions, but achieving that outcome requires positive results of future demonstration tests, and field studies of EOR and sequestration. The technical goals to be accomplished are much more challenging than any other environmental control venture addressed by industry date. As noted by Deputy Assistant Secretary for Clean Coal, Dr. Julio Friedmann, "This is not a power plant; this is a carbon refinery".[3]

We do not know enough <u>now</u> to draw a conclusion about the feasibility of CCS. The work planned between now and 2020 must be completed, and supplanted by additional projects, to give CCS a chance of being commercially proven and qualify as the best system of emission reduction.

[3] Christa Marshall, *Major coal project hits snag, but industry remains enthusiastic,* ClimateWire (Feb. 28, 2014), http://www.eenews.net/climatewire/stories/1059995313/print (subscription required). Hereafter ClimateWire (Feb 28 2014).

SECTION 1

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) on January 8 of 2014 published New Source Performance Standards (NSPS) for fossil fuel power plants limiting emissions of carbon dioxide (CO_2) to 1,100 lbs per MWh for coal-fired units, as measured over a 12-month averaging period.[4] The CO_2 emission rate from state-of-art coal-fired power stations approximates 1,800 lb/MWh[5] – consequently, some form of CO_2 capture is necessary to meet the proposed rate. There is no presently commercial means of generating electrical power from coal that emits CO_2 at 1,100 lbs per MWh without carbon capture. Both pulverized coal-fired ultra-supercritical boilers and integrated gasification/combined cycle units are nearly identical in thermal efficiency and CO_2 emission rate.[6]

The EPA presumes a proven capability of carbon capture and sequestration (CCS) technology that does not exist. The EPA in the proposed NSPS rule cite numerous industrial applications and demonstration tests of CCS as evidence that the technology is adequately demonstrated, and can be broadly applied. These industrial applications and demonstrations certainly increase our understanding and experience with CCS – but do not certify CCS as commercial and the best system of emission reduction.

This paper summarizes CCS commercial experience in North America. Three categories of CO_2 capture equipment are addressed – postcombustion CO_2 control, precombustion carbon removal (applied to integrated gasification/combined cycle), and oxycombustion.

As of February 2014, the sole operating demonstration of CCS that simulates the complete scope of activities at a power plant is the 25 MW-equivalent test of amine-based postcombustion CO_2 removal at Alabama Power's Plant Barry. In Canada, a 110 MW postcombustion process will be operating at Sask Power's Boundary Dam station by late 2014. The first full-scale application of precombustion CCS in solely utility duty will be at Mississippi Power's Kemper County Station, also in 2014.

Proponents of CCS state its status is no different than of flue gas desulfurization (FGD) or selective catalytic reduction (SCR) for nitrogen oxides (NO_x), when NSPS was issued

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[4] *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units,* 40 CFR Parts 60,70,71, and 98, Federal Register /Volume 79, No. 5, January 8, 2014. Hereafter GHG Rule.

[5] *Use of CO_2 Emission Rate Data to Derive Achievable NSPS for Coal-fired Electric Generating Units*, Supporting Material for Discussion between the American Coalition for Clean Coal Electricity and EPA, July 31, 2013.

[6] *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, DOE/NETL Report 2011/1498, Revision 1: September 19, 2013 (Original: May 27, 2011). See Exhibits ES-14, ES-15.

requiring flue gas desulfurization (FGD) and selective catalytic reduction (SCR).[7] To the contrary, timelines describing FGD and SCR development show these technologies had been applied on power generation equipment both in the U.S. and internationally. This experience enabled designing FGD and SCR process equipment for domestic coals and site conditions with confidence – enabling NSPS limits to be met.

CCS is more complex than any control option applied to date. Everything about CCS – the quantity of material captured from the gas stream, the number of individual process steps, the volume and pressure of byproduct to be managed, the transport distance required, and securing a long-term fate – represent multiple increases in complexity and scope compared to FGD. These technical challenges are matched by uncertainties in legal and jurisdictional matters affecting sequestration.

Each of these items is elaborated as follows:

Quantity of Material Removed. It is perhaps the volume of material collected and stored that most distinguishes CCS from any previous controls on flue gas. Figure 1-1 compares the mass of SO_2, NO_x, and CO_2 (as tons/y) to be removed from the gas stream of a 500 MW power plant to satisfy present-day environmental mandates and the proposed GHG NSPS. The graphic – employing a logarithmic scale on the vertical axis – compares emissions for both eastern bituminous (E. Bit) and Powder River Basin (PRB) coals, for 80% capacity factor.

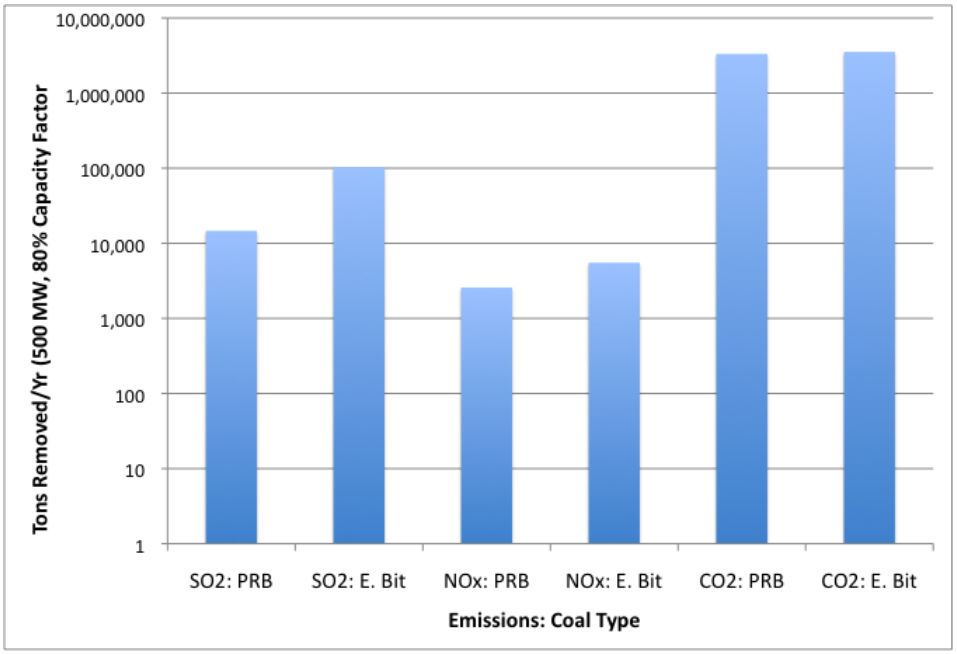

Figure 1-1. Flue Gas Emissions: 500 MW, 80% Capacity Factor, Powder River Basin and E. Bituminous Coal.

[7] Statement by Peter Tsirigotis, U.S. Environmetnal Protection Agency, to the EPA Science Advisory Board, December 5, 2013.

As shown in Figure 1-1, the amount of CO_2 removed from the gas stream exceeds by a factor of 15 the amount of SO_2 removed by FGD for high sulfur coals. For PRB coal the CO_2 removed exceeds SO_2 removed by over a factor of 100, and exceeds the amount of NO_x removed by a factor of 1000**.**

Even EPA's proposed standard of 1,100 lbs/MWh CO_2 generates significant volume of material. The 500 MW unit in Figure 1-1, if complying with the proposed 1,100 lbs/MWh CO_2 limit, in a year will remove almost 1.2 M tons of CO_2. This amount of CO_2 displaces 1.5 M m^3 of volume at the supercritical pressures that characterize sequestration.

Complexity. CCS is far more complex than FGD or SCR. As an example, amine-based postcombustion control – perhaps the most widely discussed CCS technology – requires up to twelve separate process steps to capture CO_2.[8] Sask Power's Boundary Dam demonstration project is reported to require integrating over 125 separate operations into an integrated working system.[9]

Byproduct Fate. In comparison to FGD byproduct, which is typically managed as a solid on-site or at adjacent properties, captured CO_2 is compressed to 100 atmospheres and transported dozens of miles – under the most favorable conditions. Most cost studies, such as those offered by the National Energy Technology Laboratory, assume a 50-65 mile transport distance.[10] The compressed CO_2, if not reused for oil recovery, is injected 4,000 to 8,000 feet below the earth's surface in a repository where it is projected that physical and chemical reactions over time will secure the material.

These distinguishing features of CCS – large byproduct quantity, complexity, and uncertain byproduct fate – should prompt EPA to recognize that commercially proving CCS requires more demonstrations than have been completed to date. Additional demonstrations are necessary to enable results to be (a) "scaled" to commercial size equipment, (b) "generalized" to the array of fuels and sites nationally, and (c) assure the processes operate in a system-compatible manner.

This report will assess the state of present demonstrations and the need for additional work. Section 2 reviews FGD and SCR evolution, and compares progress to that projected for CCS. Section 3 overviews the state of demonstration and commercial application for postcombustion control, while Sections 4 and 5 present the same for precombustion and oxycombustion, respectively. Section 6 addresses issues confronting CO_2 fate for enhanced oil recovery or sequestration, while Section 7 presents a timeline for commercialization. Section 8 offers conclusions.

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[8] *A Review of Carbon Capture and Sequestration (CCS) Technology*, prepared for the Utility Air Regulatory Group, December 2008. See page 4-2 and Figure 4-1.
[9] Comments by Max Ball, Manager, Clean Coal Technologies, Sask Power, during Panel Discussion: *Power Plant of 2025 – What Are We Thinking Now?,* Air Quality IX, October 21, 2013, Arlington, VA. Hereafter Ball 2013.
[10] *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, Revision 1* – September 19, 2013 (Original – May 27, 2011). Report DOE/NETL-2011/1498.

SECTION 2

ENVIRONMENTAL CONTROL TECHNOLOGY EVOLUTION

This section examines the historical path in the evolution of the commercialization and widespread deployment of FGD and SCR at electric generating units (EGUs). Parallels will be drawn in Section 7 with the development path for CCS. First, the attributes of a commercially proven process are defined.

2.1 COMMERCIAL STATUS: AVAILABLE vs. PROVEN

Historically, regulators and generation owners have had a different view as to what "hurdles" must be passed for a technology to be ready for use. Regulators typically focus on what must be accomplished for a technology to be offered for sale and whether the technology has been adequately demonstrated. In contrast, owners seek assurance a technology is proven and will not fail in a manner to compromise reliability.

A control technology is considered "commercially available" if a supplier offers to design, deliver, construct, and successfully start-up a process and turn over operation to the owner. In contrast, a technology is considered "commercially proven" when experience demonstrates most risks have been identified and accounted for in design. Critical is the scope and significance of the guarantee – is it adequate to protect the owner from undue risk and compensate for losses if the equipment fails?

EPA acknowledges the evolutionary path of control technology in the preamble. Specifically, EPA describes the difference between a first-of-a-kind (FOAK) and the Nth-of-a-kind product (NOAK).[11] Notably, EPA considers only improvements in the path from a FOAK to a NOAK – and ignores the possibility that additional experience will uncover risks that elevate cost or compromise performance. In reality, the evolution of a control technology from FOAK to NOAK is unchartered – this path is laden with "downside" risks as well as opportunities for cost savings.

That "downside" risks are incurred with evolving control technologies is evident by examining the evolution of controls for particulate matter, SO_2, and NO_x. Refinements to particulate matter controls tried in the mid-1970s included pre-chargers to enhance the performance of electrostatic precipitators (ESPs) and fabric filters to capture particulate matter generated by high sulfur coal. These refinements were not successful, at least in their first decade of development. Early generation pre-chargers provided less performance improvement to ESPs than initially estimated[12] and collecting particulate

[11] GHG Rule, page 1476.

[12] Anderson, M.H., et al., *High Intensity Ionizer Development*, Proceedings of Third Symposium on the Transfer and Utilization of Particulate Control Technology: Volume III. Particulate Control Devices, EPA600-9-82-005c, July 1982 (available from National Service Center for Environmental Publications).

matter from high sulfur coal with a fabric filter increased gas pressure drop.[13] Regarding SO_2 control, early FGD processes utilized packed bed absorbers in an attempt to minimize costs; these absorbers plugged and compromised reliability. Early NO_x controls involved aqueous scrubbing of NO_2 and regenerable, moving and fixed bed processes for combined NO_x and SO_2 control.[14] These concepts – appealing and the subject of considerable pilot plant and demonstration tests – were all commercially offered; that is at least one supplier offered the product. However, guarantees of performance – and a lack of experience assuring reliability – did not match owners' needs. Ultimately these processes were withdrawn from the market.

Further details documenting the evolution in FGD and SCR are presented subsequently. This experience provides a reference timeline to compare CCS evolution.

2.2 EVOLUTIONARY STEPS: FLUE GAS DESULFURIZATION

FGD has been the focus of development efforts for decades, with early installations in 1930s England at the Battersea, Swansea, and Fulham Stations.[15] These FGD concepts, reflecting simply the first desulfurization steps of 1970s-era technology, set the stage for early commercial applications. Most notably, in Japan the first commercial installation of FGD in 1964 was an early variant of the technology widely used today – a wet lime gypsum process constructed in 1964 by Mitsubishi Heavy Industries.[16]

In the U.S. significant pilot plant work was conducted in the late 1960s. Specifically, in 1968 Tampa Electric operated a pilot plant to evaluate the Wellman Lord process, with a second pilot test of the same concept in 1969 at Baltimore Gas & Electric's Crane Station.[17] Also in 1968 Boston Edison operated a pilot plant to evaluate SO_2 removal (from residual fuel oil) with a magnesia-based scrubbing system, completing this activity in 1970.[18] The results of this pilot plant provided the basis for a 150 MW design that operated for over 4,000 hours as a test bed.[19] A third example of early work is Utah Power & Light's pilot test of double-alkali scrubbing at Gadsby Unit 3 in 1971.[20] Additional early FGD work was conducted in the U.S. and Japan at this time.

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[13] Kushing, K., et al., 1990 Update, *Operating History and Current Status of Fabric Filters in the Utility Industry,* Proceedings: Eighth Particulate Control Symposium, Volume 2: Baghouses and Particulate Control for New Applications, EPRI GS-7050, Volume 2, November 1990.

[14] Session 4A: *Clean Coal Demonstrations,* Proceedings: 1993 SO_2 Control Symposium, Volume 1, EPRI TR-103289-V1, November 1993.

[15] (*1977) A History of Flue Gas Desulfurization Systems since 1850*, Journal of the Air Pollution Control Association, 27:10, 948-961, DOI: 10.1080/00022470.1977.10470518. See Page 995. Hereafter APCA FGD History.

[16] Ando, J., et al., *SO_2 Abatement For Stationary Sources In Japan*, EPA-600/7-77-103a, September 1977. See page 3-3, Table 3-1.

[17] APCA FGD History. See page 958.

[18] *Flue Gas Desulfurization and Sulfuric Acid Production via Magnesia Scrubbing*, EPA Technology Transfer Capsule Report, Report EPA-625/2-75-007 (undated).

[19] Koehler, G., et al., *The Magnesia Scrubbing Process as Applied to an Oil-fired Power Plant,* EPA Report EPA-600/2-75-057, October 1975.

[20] APCA FGD History. See page 958.

The earliest limits in SO_2 emissions adopted by local communities in Japan and the U.S. were based on lowering fuel sulfur content. The first NSPS for SO_2, issued in the U.S. in 1971, codified a limit of 1.2 lbs/MBtu that could be met using "compliance" coal, physical coal cleaning, or FGD. Thus, the 1971 NSPS did not require FGD for compliance – the emissions limit could be achieved by any of three means.

In 1977 Congress amended the Clean Air Act and in 1978 EPA revised the NSPS for SO_2 to a level that eliminated any option but FGD. By this time significant experience for FGD had accumulated on pilot plants and early commercial units – by 1978 commercial experience totaled slightly over 10,000 MW.[21]

The experience accumulated with FGD provided the basis for process suppliers to offer meaningful process guarantees. In practice, FGD reliability problems continued into the late 1970s and early 1980s, as documented by the ongoing FGD surveys sponsored by EPA.[22] It was not until the late 1980s that FGD reliability improved to where it ceased to be an issue for most generating stations.

2.3 EVOLUTIONARY STEPS: SELECTIVE CATALYTIC REDUCTION

The events that prompted SCR application followed FGD by about a decade. In the late 1970s, SCR had been tested at numerous pilot plants in Japan as well as in several commercial demonstration tests. Both the EPA and the Electric Power Research Institute (EPRI) operated plot plants on domestic U.S. fuels. Continued advances in combustion NO_x control technology in the U.S. in the early 1980s provided a low cost means to control NO_x from existing units.

SCR was most extensively deployed in Europe – particularly Germany – in response to acid deposition concerns in regions such as the Black Forest. Figure 2-1 presents a timeline depicting SCR installations in Europe in the 1980s, and of key early applications in the U.S. on coal-fired power stations. By the mid-1990s, international experience on coal totaled approximately 40,000 MW in Europe and perhaps 25,000 MW in Japan, with U.S. experience totaling about 4,000 MW.

[21] Shattuck, D., et al., *A History of Flue Gas Desulfurization (FGD) – The Early Years*, United Engineers & Cnstructors Working Paper.
[22] Melia, M.T., et al., *Project Summary: Utility FGD Survey October 1983-September 1984*, Report EPA-340/1-85-014, October 1984.

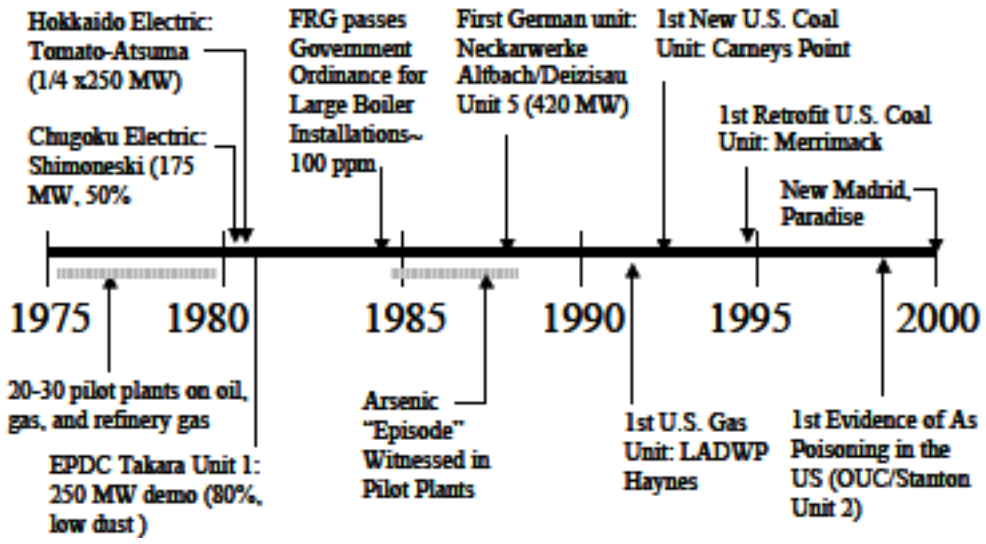

Figure 2-1. Timeline for SCR Development and Early Application

The use of SCR was effectively mandated in eight northeastern states in the U.S. by 1997. The "NO_x SIP-Call" required northeastern states to lower system-wide NO_x emissions to 0.15 lb/MBtu –requiring SCR on most on large capacity units. Also in 1997, the EPA issued NSPS for NO_x that required SCR on most coals – excepting lignite, for which experience was limited. By the year 2000, in the U.S. about 12,000 MW of capacity were equipped with SCR.

2.4 IMPLICATIONS FOR CCS

The timeline of experience with FGD and SCR is instructive for CCS.

Unlike FGD and SCR, the status of CCS when mandated by NSPS lacks authentic experience at large commercial power plants. The only CCS applications are located at either small commercial units producing CO_2 for industrial use, or large pilot plant or demonstration-scale equipment. EPA's preamble to the NSPS cites applications that purportedly demonstrate CCS. Table 2-1 summarizes EPA's selected reference list.

Table 2-1. Summary of CO_2 Capture, CCS Projects Identified in Preamble

Owner/Plant	CO_2 Captured (1000 tons/y)	Fraction (Capacity of Host) Treated	CO_2 Removal Method	Host Unit Capacity MWgross	Duty Cycle	Operating History	CO_2 Use or Fate	Transport
AES/ Warrior Run	110	5-6% (12 MW)	Amine	180	Utility Power	Since 2000	On-site food processing	N/A
AES/Shady Point	66	4% (7 MW)	Amine	175	Utility Power	Since 2000	On-site food processing	N/A
Searles Valley Minerals	270	100% (27.5MW)	Amine	27.5	Steam, Power	Production since 1978	Chemical production	N/A
Great Plains Synfuels Plant	1,600	100% for 50%removal	Pre-comb Rectisol	1000	Chemicals, Syngas	Since 1989	EOR	205 miles to Weyburn
AEP/ Mountaineer	75-90% of 20 MW	20 MW	Chilled NH_3	1300	Pilot plant at power plant	4Q/2009-2Q/2011	On-site deep saline reservoir	Within plant boundaries
Vattenfall: Schwarze Pumpe	70	100%	Oxycom-bustion	10	Pilot plant at power plant	2008-present: planned to 2018	Released after capture	N/A
Alabama Power/Barry	100	3% (25 MW)	Amine	700	Pilot plant at power plant	CO_2 capture: 6/2011–present	Deep saline reservoir	12 miles
Miss. Power/ Kemper County	3,500	100%, 65% capture	Pre-comb	582(net)	Utility Power	Startup: 2015	EOR	Heidelbery Oil fields
Sask Power Boundary Dam	1,000	100%	Amine	110	Utility Power	Startup: 2014	EOR and deep saline formation	Pipeline transport
Texas Clean Energy	2,700	100%	Pre-comb 90%	400 250(net)	Chemicals, Power	Proposed: 2017	EOR	TX Permian Basin
Hydrogen Energy CA (HECA)	2,600	~100%	Pre-comb	390 250(net)	Chemicals, Power	Proposed: 2017	EOR	5 miles to Elk Hills
NRG/W.A. Parish	1,400 tons/y	50% of one unit	Amine	240	Utility Power	Proposed: 2015	EOR	TX Gulf Coast

Each reference unit cited in Table 2-1 will be described by category in either Section 4 (Postcombustion), Section 5 (Precombustion), or Section 6 (Oxycombustion). Further, the units that are designed or operated with subsidies from federal, state, or other governmental agencies will be identified.

Only one unit cited by EPA in Table 2-1, the Great Plains Synfuels Plant that is owned by the Dakota Gasification Company, represents a commercial scale pre-combustion process – but this facility manufactures natural gas and does not generate power.[23] The Great Plains Synfuels Plant captures about 50% of the CO_2 generated for transport to the Cenovus Energy oilfields via a 205-mile pipeline. Mr. Lyle Witham, Manager of Environmental Services for Basin Electric Power Cooperative, commented to the EPA Science Advisory Board on January 21 2014 that the Great Plains Synfuels Plant manufactures natural gas and does not generate power.[24] Consequently, the plant operation is defined by delivering a marketable byproduct, at a production rate the owner can control. Operating a plant to satisfy a wholesale or regulated power market that can vary on an hour-by-hour basis is very different.

Further details of these reference cases and a timeline for CCS development will be presented in subsequent sections.

[23] The report *CCS Institute in the Global Status of CCS: 2013* report cites twelve large-scale integrated CCS projects world-wide in operation; Great Plains Synfuel manufacturers natural gas but does not generate power. Of the eleven remaining projects cited by the CCS Institute eight address natural gas processing (In Salah, Val Verde, Shute Creek, Sleipner, Snohvit, Century, Petrobas Lula Oil field, and Lost Cabin), two fertilizer production (Enid and Coffeyville), and one hydrogen production (Air Products Steam Methane).

[24] Witham, L., *Comments Addressing The Role of Carbon Capture and Sequestration in The Environmental Protection Agency's Proposed Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Generating Units*, January 21, 2013. Hereafter Withan 2014 EPA SAB Testimony. Available at: http://yosemite.epa.gov/sab/sabproduct.nsf/a84bfee16cc358ad85256ccd006b0b4b/3ba3d4561adc643985257c4300587aec!OpenDocument&Date=2014-01-21

SECTION 3

POSTCOMBUSTION CO_2 CAPTURE

Postcombustion CO_2 control is the focus of several demonstrations in North America and Europe. This section will summarize the status of key demonstrations in authentic power industry duty that can influence the technical feasibility.

A description of postcombustion CO_2 capture is presented in prior references developed by UARG[25] and the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL).[26] Specifically, Section 4 of the 2012 UARG document presents a flowsheet describing the components of the most common concept tested, that employing amine-derived sorbents. The DOE/NETL status report contains similar information. Both reports also describe alternative reagents or sorbents to capture CO_2 in a "postcombustion" manner.

Table 3-1 summarizes the status of the major pilot plant or demonstration tests on coal-generated combustion products, focusing on North America but including key activities in Europe. Some of the projects in Table 3-1 do not represent the complete scope of activities required for commercial CCS, but are included because EPA believes these to be valid reference cases. The rationale why these incomplete projects do not reflect authentic CCS duty is presented in this section.

The pilot plant and demonstration projects summarized in Table 3-1 are discussed categorically, in terms of being completed, operating, or in design, construction, or planning. Where relevant, total project cost and the degree of cofunding by federal, state, or local government is cited. Projects outside North America are included but addressed separately. Due to differences in fuel composition, plant design, and plant operating duty, the results of these projects may be limited in applicability to North American units.

3.1 COMPLETED

The sole project completed is the American Electric Power (AEP) 20 MW pilot plant based on Alstom's chilled ammonia process. This pilot plant operated for a period of 30 months. A total of 15,000 tons of CO_2 were sequestered in a nearby saline aquifer.

[25] *A Review of Carbon Capture and Sequestration (CCS) Technology*, issued by the Utility Air Regulatory Group, June 25, 2012. Hereafter 2012 UARG CCS.
[26] *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity,* Revision 1, August 2007, DOE/NETL -2007/1281. Hereafter DOE/NETL 2007 Baseline.

Table 3-1. Summary of Postcombustion CO_2 Pilot Plant and Demonstration Projects: North America and Europe

Project	Host (Co-Sponsors)	Capacity (MW) CO_2 Removed/Yr	CO_2 Capture Technology	CO_2 Fate	Construction Initiated/ Operational	Cost, $M (Total/Subsidy)
Mountaineer	AEP (Alstom, others)	20 MW pilot plant. 15,000 tons CO_2 per 15 months	Postcombustion: Chilled ammonia	Saline: 1.5-mile depth in Mt. Simon Sandstone.	Operations: Oct '09 thru Dec '10. Complete.	100/16
Warrior Run	AES	12 MW. 110,000 tons/yr	Postcombustion amine	On-site food production	Operating since 2000	N/A
Shady Point	AES	7 MW. 66,000 tons/yr	Postcombustion amine	On-site food production	Operating since 2000	N/A
Searles Valley Minerals	Nirma	28 MW. 270,000 tons/yr	Postcombustion amine	Chemicals production	Operating since 1995	N/A
Plant Barry	Southern Company, MHI, EPRI	25 MW pilot plant; 550 tons/day CO_2	Postcombustion: MHI KM-CDR amine process	Saline: 11-mile pipeline to Citronelle dome (0.44 tons/4 yrs).	CO_2 capture: 2Q/2011 to 4Q/2014. Sequestration monitoring to 2017	TBD
W.A. Parish	NRG Energy (DOE)	240 MW 1.65 M tons CO_2/year	Postcombustion: Fluor Econamine, experimental reagents	EOR: 80 miles to Hilcorp's West Ranch	Operations: planned 2015	339/167
Boundary Dam (Unit 3)	Sask Power Alliance	110 MW 1 M tons CO_2/year	Postcombustion: Cansolv	EOR at Weyburn, excess CO_2 to saline reservoir.	Construct: 2012 Operation: 2014	1,335/240 (Canadian)
Brindisi	ENEL, Eni	48 MW pilot plant 8,000 metric tons/y (See Brindisi note)	Postcombustion – amine, others	EOR: Stogit field north Italy	Anticipated 2012 operation. Status not confirmed	€ 400/100 (euro)
Ferrybridge	Scottish Southern Energy	5 MW pilot plant 100 tons/day)	Postcombustion amines	Release after capture	Nov 2011 through December 2013.	£ 21/6 (sterling)
Wilhelmshaven	E. On	3.5 MW pilot plant	Fluor Econamine	Release	Oct 2012 start-up: at least 1,600 operating hrs.	N/A

Note: Capacity reported as gross electric MW, unless noted otherwise.

Brindisi: 8,000 tons CO_2/yr are reported but this value is significantly less than the CO_2 attributed to 48 MW of coal-derived generating capacity.

Subsequent to this pilot plant test, AEP planned to extrapolate these results to a large-scale demonstration (235 MW) at the Mountaineer site, using the same chilled ammonia process. The project was cancelled due to financial concerns and lack of clarity of CO_2 regulations.

3.2 OPERATING

Four coal-fired units are the source for CO_2 that is captured and used for either commercial purposes or for a pilot plant test.

Three units support commercial production of food or chemicals and do not transport or sequester CO_2. These three plants are:

AES/Warrior Run. This 225 MW coal-fired power plant provides a 12 MW-equivalent slipstream that provides CO_2 for food processing at an adjacent site. CO_2 transport and re-use issues are not addressed.

AES/Shady Point. This 175 MW coal-fired power plant provides a slipstream equivalent to 7 MW which, similar to Warrior Run, provides CO_2 for food processing at an adjacent facility. CO_2 transport and re-use issues are not addressed.

Nirma/Searles Valley Minerals. Flue gas from this 28 MW coal-fired power plant provides CO_2 for on-site mineral processing; CO_2 transport and re-use issues are not addressed.

Only one project operates with a scope that includes transporting and sequestering CO_2:

Southern Company/Plant Barry. The Plant Barry 25 MW CO_2 demonstration of MHI's amine-based technology presently removes approximately 500 tons of CO_2 per day from flue gas at Alabama Power's Barry Unit 3. This project, in addition to demonstrating CO_2 capture, employs compression, pipeline delivery, and sequestration of CO_2 in saline aquifers. Operation started in June of 2011 (CO_2 capture only), with sequestration initiating in August of 2012. Operations will continue through 2014, including monitoring of the sequestration site through 2017.

3.3. DESIGN, CONSTRUCTION, OR PLANNING

Two North American projects are relevant: one in final construction, and one in planning and financing.

Sask Power Alliance/Boundary Dam. The Sask Power Alliance is in final construction stages of retrofitting Sask Power's Boundary Dam Unit 3 with the Cansolv postcombustion control process (combined CO_2 and SO_2 removal). This 110 MW unit is anticipated to produce 1 M tons of CO_2 per year, most of which will be deployed for EOR at the Weyburn fields. Captured CO_2 not directed to EOR will be sequestered by the Aquistore Project at a nearby deep saline formation. Construction initiated in 2012 and is almost complete; the unit is expected to be operating in 2014. The provincial government is providing 18% of total project funds.

W.A. Parish. A preliminary engineering study is underway addressing the retrofit of a 240 MW-equivalent demonstration plant, using Fluor's Econamine amine-based CO_2 control process. The project will annually capture 1.65 million tons of CO_2 for EOR. The Parish demonstration status is not yet finalized as financing is not secured.[27] The earliest the unit will operate is 2015 –pending success in financing. The DOE is providing 49% of total project funds.

3.4 PROJECTS OUTSIDE NORTH AMERICA

Several postcombustion CO_2 control projects operate outside of North America, with additional demonstration plants planned. Due to differences in fuel composition, plant design, and plant operating duty, the results of these projects may have limited applicability to North American units.

Three pilot plants – ranging in equivalent generating capacity from 3.5 to 48 MW – presently operate. These are:

E.On/Wilhelmshaven. E.On operates a 3.5 MW equivalent pilot plant at their Wilhelmshaven Station on the North Sea. This pilot plant, which tests the Fluor Econamine process, began operating in late 2012. The financing details are not known.

ENEL/Brindisi. ENEL operates a 48 MW pilot plant which began capturing CO_2 in 2011. Since 2012 the CO_2 has been transported to the nearby Stogit oil field for EOR. The project requires an investment of € 400m (euros) of which 25% is public funds. The Brindisi pilot plant data are intended to support design of a postcombustion capture system for the Porte Tolle station, although plans for this full-scale demonstration have been put on hold.

SSE/Ferrybridge. Scottish and Southern Energy operate a 5 MW pilot plant at the Ferrybridge station, which commenced operation in 2012 and will operate through 2013. The captured CO_2 is not transported or sequestered. The project is anticipated to require an investment of £ 21m (sterling), of which public funds contribute £ 6m (sterling).

Additional postcombustion control demonstrations at commercial scale are planned but financing is not complete. An example is the 250 MW-equivalent slipstream treatment facility at the 1,000 MW Maasvlakte power plant in Rotterdam, The Netherlands (the ROAD Project). This proposed $1.6 M project, if successfully financed, would sequester 1.1 M tons of CO_2 15 miles to an offshore depleted gas field. A financing decision is anticipated in 2014, enabling operation by perhaps 2018.

In conclusion, the sole relevant experience with postcombustion CO_2 control is with Plant Barry's 25 MW-equivalent pilot plant. The Sask Power 110 MW Boundary Dam unit may soon be operating and provide similar information. The small commercial applications (Warrior Run, Shady Point, Searles Valley Minerals) do not transport or

[27] *DOE Issues Final EIS for W.A. Parish, GHG Monitor*, March 13, 2013, available at http://ghgnews.com/index.cfm/doe-issues-final-eis-for-wa-parish/

sequester CO_2 and thus do not provide authentic utility experience or a complete scope of operation. The remaining units described in Table 3-1 either are uncertain in status due to financing or other concerns.

SECTION 4

PRECOMBUSTION CARBON REMOVAL

Precombustion CO_2 control for exclusive application to power generation is the focus of several demonstrations in North America and Europe. This section will summarize the status of these demonstrations and estimate when adequate data will be available from which to base commercial designs.[28]

A description of precombustion CO_2 capture is presented in prior references developed by UARG[29] and the DOE/NETL.[30] Specifically, Section 5 of the UARG review presents a flowsheet describing a typical precombustion concept, including CO_2 compression.

Table 4-1 summarizes the status of the major pilot plant or demonstration tests of precombustion carbon control on coal-fired power stations in North America that are either in progress or planned. Table 4-2 presents two examples of precombustion projects in Europe which are planned but for which permit and financing are not yet complete.

The pilot plant and demonstration projects summarized in Table 4-1 are discussed according to projects "operating" or in "design, construction, or planning." Projects outside North America in Table 4-2 are discussed subsequently. As with postcombustion control, differences in fuel composition, plant design, and operating duty may limit the applicability of results from units outside of North America to U.S. application.

4.1 OPERATING

The Great Plains Synfuels Project – owned by Dakota Gasification Company – has been cited as an example of utility application of precombustion CO_2 control.

This unit processes coal at a rate equivalent to generating approximately 1,000 MW of electrical power – but the plant produces chemicals and not power. The primary product is syngas which is delivered to distribution pipelines. Additional byproducts include ammonium sulfate, anhydrous ammonia, cresylac acid, naphtha, phenols, and tar oil, among others.

[28] Several precombustion processes presently support natural gas processing or chemical production. These projects and the resulting experience do not address market-based power generation and are not included in Table 4-1. Experience with individual components may be gained but not insight to integrated systems serving power generation. These facilities include, for example, natural gas processing (Val Verde, Shute Creek, Century, and Lost Cabin), fertilizer production (Coffeyville and Enid), and hydrogen production (Air Products and Chemicals Steam Methane Reformer).
[29] 2012 UARG CCS.
[30] DOE/NETL 2007 Baseline.

Table 4-1. Summary of Precombustion CO_2 Control Applications – Operating, Construction, Planned; North America

Developer/ Site	Developer	Generating Capacity (MW)/ Annual CO_2 Produced	Technology	CO_2 Fate	Construction/ Operating Schedule	Cost, $M (Total/Subsidy)
Great Plain Synfuels	Great Plains/ (DOE)	6 M tons CO_2 produced annually, 3 M tons captured.	Lurgi Mark IV gasifiers; Rectisol process removes H_2S and CO_2.	65% captured and transported 205 miles for EOR.	Completed for DOE as demo; Dakota Gasification acquired in 1988.	Federal support of $2,000 loan guarantee (1984 dollar basis) and other subsidies.
Kemper County (Ratcliffe)	Mississippi Power (DOE)	582 MW 65% CO_2 removal (~800 lb/MWh) 3 M tons CO_2	TRIG (Transport-Integrated Gasifier) with Selexol.	EOR: Denbury Resources Heidelberg Field.	Construct: 2011 Operation: 2015	5,500/400 Rate recovery, finance issues resolved.
Texas Clean Energy Project	Summit Power (DOE)	400 MW 2.9 M tons CO_2/year	IG/CC (Siemens)/ 90% capture (Rectisol w/urea).	EOR: Texas Permian Basin	Construct: 2014 Operation: 2018	2,400/450 Closed 20–yr power sales contract w/CPS.
Hydrogen Energy California (HECA)	SCS Energy, others	390 MW, 250 MW (net) 2.6 M tons CO_2/year	Pet coke/IG/CC (MHI O_2-blown gasifier)/90% capture (Rectisol w/urea).	EOR: 5-mile pipeline to Elk Hills.	Construct: 2014 Operation: 2018	4,080/440 Pending approval of certification, permitting.

Note: Capacity reported as gross electric MW, unless noted otherwise.

Table 4--2. Example Planned Precombustion CO_2 Control Applications: Europe

Developer/ Site	Developer	Generating Capacity (MW)/ Annual CO_2 Produced	Technology	CO_2 Fate	Construction/ Operating Schedule	Cost, $M (Total/Subsidy)
Don Valley Power Project	2 Co Energy Ltd.	920 MW or 650 MW (net), with 90% CO_2 capture (to 5 M tons annually).	Key suppliers reported to be Shell, GE, and BOC.	Transport via 250 mile pipeline, for sequestration in North Sea.	Finance decision 4Q 2013. Anticipated to be operational by 2018/2019.	~£ 5,000 (sterling). Not selected in 2013 UK funding but highly rated reserve project.
Teesside Low Carbon Project	Progressive Energy Ltd, BOC, International Power, National Grid, Fairfield Energy, Premier Oil.	850 MW plant with 400 MW-equivalent slip-stream (2.5 M tons/yr).	Key suppliers reported to be BOC/The Linde Group, others.	Most of 2.3 M tons stored in depleted oil field in North Sea; a small fraction to a saline reservoir.	2016 reported if investment completed by 2013.	Not disclosed. Not selected in 2013 UK funding but highly rated reserve project.

Note: Capacity reported as gross electric MW, unless noted otherwise.

As noted by Mr. Lyle Witham to the EPA Science Advisory Board on January 21, 2014, the experience of the Great Plain Synfuel Plant with carbon removal does not readily transfer to power generating facilities.[31] Specifically, the Synfuels Plant operates to maximize generation of syngas and products such as CO_2 on a 24x7 basis – thus the unit continually operates at "full" fuel throughput to maximize revenue.[32] This mode of operation differs from an electric generating unit, which is required to change fuel throughput throughout the day, responding to market demand for power. It should also be noted the Great Plains project was not conceived as a private venture but a DOE-funded response to the global energy "crisis" of the late 1970s. Consequently, the present economics of operations – being responsible for only modest capital payments – may not reflect conventional business practice.

4.2 DESIGN, CONSTRUCTION, PLANNED (NORTH AMERICA)

Three precombustion projects are either in design, construction, or planning:

Kemper County/Ratcliffe. Mississippi Power's greenfield 582 MW lignite-fired IG/CC process will be the first in North America to capture carbon prior to the gasifier for sequestration. The process design calls for 65% of the CO_2 to be captured, compressed and transported, and deployed for EOR. Construction of this generating unit initiated in 2011, is presently 75% complete, and is expected to be commercially operating in 2015. No major technical issues have emerged during the final design and construction that challenge the viability of the project. Approximately 8% of the total project cost is subsidized by the DOE. The total project cost has escalated beyond initial projections but all financing issues have been managed.[33, 34]

The project schedule has been revised and a mid-2015 startup date is expected.[35] Both the escalated cost and the delayed schedule illustrate the uncertainty and risk associated with next-generation projects

Texas Clean Energy Project. This greenfield 400 MW IG/CC generating unit will capture 90% of the CO_2 produced – 3 million tons of CO_2 each year, with 2.5 million dedicated for EOR in the Permian Basin. The process will employ Siemens combustion turbines and gasifiers. The power output from this $2.4 B investment ($0.45 M from DOE) is 100% committed (i.e., under contract). All permits have been issued.

The schedule for the project depends on financing which is still being negotiated.

[31] Witham 2014 EPA SAB Testimony.
[32] L. Withum and A.T. Funkhouse, Personal Communication, April 7, 2014.
[33] *Southern Withdraws $1.5B Loan Guarantee for Kemper Plant*, GHG Monitor, April 15, 2013, available at http://ghgnews.com/index.cfm/southern-withdraws-15b-loan-guarantee-request-for-kemper-plant/.
[34] *Mississippi Power Requests $600M for Kemper County IG/CC Plant*, Power Engineering, April 24, 2013, available at http://www.power-eng.com/articles/2013/04/mississippi-power-requests-600mn-for-kemper-county-igcc-plant.html
[35] *$5.5 B Kemper carbon capture project to be delayed until 2015*, ClimateWire, April 30, 2014.

Hydrogen Energy California (HECA). The HECA project employs IG/CC, fueled by residual fuel oil and petroleum coke, to generate 250 MW of power while producing hydrogen and commercial products such as fertilizers. The carbon removal precombustion system will capture 90% of the CO_2 generated, equal to 2 M tons per year, which will be used for EOR in nearby oil fields. Approximately 12% of the total project funds ($4.08 B) is provided by the DOE.

A change in ownership (the project was acquired by SCS Energy in 2012) prompted the operating permits to be revised and resubmitted. The relevant permits are presently under review by the California Energy Commission.

As noted, all three units cited receive significant federal financial support.

4.3 DESIGN, CONSTRUCTION, PLANNED (EUROPE)

Several precombustion carbon removal projects are planned outside of North America. Due to differences in fuel composition, plant design, and plant operating duty, the results of these projects may be limited in applicability to North American application.

A leading demonstration candidate in the U.K. is the Don Valley Power Project (South Yorkshire). Table 4-2 reports this project will capture 90% of the CO_2 from a 950 MW (gross) power station – up to 5 million tons of CO_2 annually. The captured CO_2 will be transported 250 miles to a sequestration site in the North Sea. Financing for this £5 B (sterling) project, at present uncertain, is being sought to enable a 2018 /2019 operation.

An additional project – the Teeside Low Carbon – is located in the U.K. and awaits an investment decision. The permit and finance status are uncertain. Additional precombustion projects are proposed in China utilizing gasification technology on coal-to-chemicals facilities, but plans at present are undefined and the timing uncertain.[36]

[36] CCS Institute Global Status: February 2014. Page 15.

SECTION 5

OXYCOMBUSTION

The process of oxycombustion employs firing coal in an exclusive O_2 gas stream that is generated by removing nitrogen from air. As a result the main product of combustion is CO_2, which after removing species such as nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury and other trace elements, can be directly processed for compression, transport, and sequestration.

A description of oxycombustion CO_2 capture is presented in prior references developed by UARG[37] and the U.S. Department of Energy.[38] Specifically, Section 5 of the 2012 UARG document presents a process flowsheet. The DOE/NETL status report contains similar information.

Table 5-1 summarizes the status of major oxycombustion projects, focusing on North America but including key activities in Europe. Projects in progress or planned are included. Some of the projects in Table 5-1 do not represent the complete scope of activities required for commercial CCS, but are included as EPA believes these to be valid reference cases.

The pilot plant and demonstration projects summarized in Table 5-1 are discussed categorically, in terms of either completed, operating, or in design, construction, or planning.

5.1 COMPLETED

Two pilot plant test programs have been completed and provide exploratory data at small scale and limited operations.

Babcock & Wilcox. As a precursor to the FutureGen2.0 project, a small pilot test was conducted to provide the basis for a demonstration process design. These tests were conducted on a 10 MW-equivalent pilot plant.[39] The duration of operation was short – totaling less than 300 hours – but results are the first step in establishing the design basis for a demonstration plant. The scope of testing addresses oxygen separation and production of an exclusive CO_2 effluent. This research activity was significantly cofunded by the DOE.

[37] 2012 UARG CCS.
[38] DOE/NETL 2007 Baseline Report.
[39] *Technical Considerations for Oxycombustion Flue Gas Conditioning*, Babcock & Wilcox Technical Paper BR-1842, EPRI Power Plant "Mega" Symposium, Baltimore, MD, August 2010. This work is widely reported on the thermal-throughput basis, or 30 MW.

Table 5-1. Status of Oxycombustion Demonstration Tests

Utility/Operator	Electrical/Heat Throughput	CO_2 Fate	Construction/Operating Schedule	Cost, $M (Total/Subsidy)
FutureGen 2.0 Alliance	167 MW	1. 1 M tons/yr, transport via 29 mile pipeline to Mt. Simon deep saline reservoir.	2013 start of construction. Planned completion by 2017.	1,680/1,000 Preliminary engineering complete. Completing financing and permitting.
Vattenfall AB Janschwalde, Germany	30 $MW_{(thermal)}$ (equivalent to 10 MW)	Released	Demonstration test starting 2008; continues through 2018.	Continued commercial demonstration through 2018.
Callide A Station, CS Energy, Australia	30 MW	0.27 tons/yr, sequestered via on-shire deep saline.	Demonstration test starting 2012; continue through 2014.	$241 M (AUS). Startup operations commenced in early 2012.
Lacq, Total, France	30 MW_t/10 MW(e) Heavy Fuel Oil	75,000 CO_2 tons annually injected in a depleted gas field.	Demonstration test starting 2010; completed 2013.	Two year pilot test scheduled from 2010 through 2013. The government support for the 60 M € project is unknown.
White Rose	436 MW	2 M tons/yr; 40 mile transport for offshore sequestration in deep saline reservoir.	Final investment decision in 2015, possible initiation of construction in 2016. Start up 2020.	Selected by UK government in CCS Competition to proceed to front end engineering study.

Note: Capacity reported as gross electric MW, unless noted otherwise.

Total (Lacq, France). A 10 MW pilot plant firing heavy fuel oil operated at the Total Lacq Refinery from 2010 through most of 2013. This unit is included as a reference project even though experience is with fuel oil and not coal, as there is little process information on any fuel. This project entails a more complete scope, with 75,000 tons of CO_2 annually injected into a depleted natural gas field. The extent of government support for the 60 M € project is unknown.

5.2 OPERATING

Two demonstration units are operating at small scale but simulate a complete scope of CO_2 separation and reuse or sequestration.

Vattenfall AB. This 10 MW pilot plant in Janschwalde, Germany fires coal and is approximately halfway through a decade long test. This pilot plant, which started operation in 2008, represents a complete scope of activity, including injection of 75,000 tons of CO_2 annually into a depleted gas field. Plans for this unit are to operate for a complete decade – a testament to the longevity required to acquire data from different fuels and operating conditions. These results will define the role of coal composition and variable operating conditions, although applicability will be limited due to the small scale. The extent of government support for the € 70 M project is unknown.

Callide A Station. CS Energy has operated a 30 MW equivalent pilot plant – at present the largest in the world – at the Callide Station since 2012. Tests are planned for approximately 2 years, and include sequestering the CO_2 effluent in a saline reservoir. Pending successful results at Callide a larger (150-200 MW) unit will be built and operated for 3-4 years. The $ 206 M (AUS) project is approximately 25% subsidized by the Australian government.

5.3 DESIGN, CONSTRUCTION, PLANNED (NORTH AMERICA)

The sole North American project is the U.S. Department of Energy-funded FutureGen2.0. This activity, to receive $1B in DOE funds, will enable FutureGen Partners to convert a 167 MWe (gross) output unit at Ameren's Meredosia station (Illinois) to oxycombustion. The scope of work entails cleaning and compressing 90% of the CO_2 emissions generated – 1.1 M tons annually – transporting this byproduct 29 miles by pipeline for sequestration at 4,000 feet in a saline reservoir in the Mt. Simon formation. The project, which is anticipated to cost $1.68 B, has initiated preliminary "front-end" engineering.[40] Final design and construction awaits award of a state permit to inject CO_2 and completing financing by the FutureGen Industrial Alliance.

5.4 PROJECTS OUTSIDE NORTH AMERICA

Table 5-1 also presents the status of a key oxycombustion demonstration project outside of North America. Due to differences in fuel composition, plant design, and plant operating duty, such projects may not significantly influence oxycombustion commercial status in North America.

[40] *B&W tapped for next phase of FutureGen 2.0 carbon capture project,* PennEnergy, March 7, 2013, available at http://www.pennenergy.com/articles/pennenergy/2013/03/bw-tapped-for-next-phase-of-futuregen-2-project.html.

The White Rose project, as proposed by Capture Power, was authorized by the U.K. government in December of 2013 to proceed with engineering to further define the project cost. It is possible this project could be operational by 2019.

Other projects in Europe have been cancelled or delayed, at least temporarily.[41]

[41] CCS Institute Global Status: February 2014. Page 15.

SECTION 6

SEQUESTRATION AND REUSE

Equally important to the capture of CO_2 is its ultimate fate – what to do once removed from the gas stream. The two most prominent fates – deep saline sequestration and reuse for enhanced oil recovery (EOR) – are addressed in this section. For each option the following are discussed: the location and characterization of candidate sites, storage characteristics, the pipeline network required, and property rights.

6.1 DEEP SALINE SEQUESTRATION

Location of Candidate Sites. The DOE and the United States Geologic Survey (USGS) have estimated the potential CO_2 storage capacity available in deep saline reservoirs, with DOE reporting capacity by state[42] and the USGS by storage basins.[43] The estimates by DOE and USGS of total CO_2 storage capacity in deep saline reservoirs are premised on different assumptions; directly comparing the total capacity may not be valid.[44] Both studies report significant heterogeneity in the distribution of storage sites.

Specifically, the USGS concludes the Gulf Coast area contains almost 60% of the national CO_2 storage capacity.[45] The DOE identifies many locations in the U.S. that have access to potential significant sequestration capacity, but a number of locations remain under-served.[46] Specifically, ten states either have "zero" CO_2 storage or have yet to be assessed; another five appear capable of serving just a few 500 MW plants. Thus, CO_2 storage capacity in 30% of the states is uncertain, based on DOE's present "high level" assessment methodology. As DOE notes, the assessment is intended only to provide a "...high level overview of CO_2 geologic storage information...", and that is "...not intended as a substitute for site-specific characterization, assessment, and testing."[47] The message: uncertainties persist.

Storage Characteristics. As noted above, the CO_2 storage at any one site will not be known until the site is assessed for specific criteria. The 2012 (First) Edition of the North American Carbon Storage Atlas states the following: "It is important that a regionally extensive confining zone (often referred to as caprock) overlies the porous rock layer and

[42] *The United States 2012 Carbon Utilization and Storage Atlas*, Fourth Edition, Department of Energy, Office of Fossil Energy, available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIV/. Hereafter 2012 Carbon Atlas.
[43] *National Assessment of Geologic Carbon Dioxide Storage Resources – Results*, Circular 1386, Version 1.1, September 2013. Hereafter USGS September 2013.
[44] The DOE cites a "low" estimate of 2,700 billion metric tons of storage, while USGS cites a 50% probability storage capacity is less than 3,000 billion metric tons.
[45] USGS September 2013; see Summary on page 1.
[46] Ibid. See Appendix D.
[47] Ibid. See Appendix D.

that no major faults exist."[48] The same reference cites the importance of documenting the CO_2 storage capability, the "injectivity," and the ability of the porous rock to permanently trap CO_2. Both criteria are necessary to evaluate site potential.

These criteria cannot be evaluated until the subsurface physical characteristics of a site are mapped or documented. This analysis requires an extensive effort. The International Energy Agency (IEA), in its CCS Technology Roadmap, noted that "Experience indicates that it typically takes five to ten years from the initial site identification to qualify a new saline formation for CO_2 storage, and in some cases even longer."[49] The Global CCS Institute concurs, noting "The estimated lead time for a greenfield storage assessment can be 10 or more years."[50] In summary, it can take at least five years to evaluate a site for CO_2 storage potential.

Pipeline Network. The pipeline infrastructure must be developed. Although for CO_2 pipelines exist for EOR, there is no known capacity solely for transport for CO_2 that is not intended for EOR. The most significant barriers to expansion will be non-technical issues – addressing property rights for right-of-way access and multi-state jurisdictions.

Property Rights. In addition to acquiring right-of-way for pipelines, two other factors are important: (1) acquisition of pore space for storage over a broad area, involving multiple owners; and (2) access to the surface for monitoring.

Regarding the first topic, a critical complication is that subsurface lands with the desired pore space can be privately owned, and CO_2 injection can impact owners in multiple states. Historically, the laws that have been used to secure access to oil and gas fields from multiple owners – addressing compulsory unitization and eminent domain – may be inadequate for CO_2 injection. Resolving conflicting property rights could induce significant project delays.

CO_2 repositories must be extensive and due to their size could infringe on existing mineral, water, and private property rights (both surface and subsurface). Repositories located across state lines will introduce jurisdictional questions – particularly as CO_2 plumes migrate. Legal precedent addressing such complex subsurface issues does not exist. CO_2-derived liabilities are not fully defined and there is little basis for resolving disputes. As noted, the legal framework which exists has evolved from oil and gas rights and application of EOR. However, both offer limited experience and may not apply to the larger CO_2 disposal rates that are required to sequester power plant CO_2. The time frame for monitoring and responsibility for sequestration extends well beyond that typical for EOR and oil/gas experience.

In addition to the preceding issues, groups adversarial to coal-fired generation can impose significant delays. It has been well demonstrated that some environmental groups and

[48] *The North American Carbon Storage Atlas – 2012*, First Edition, page 18. Available at www.nacsap.com.
[49] Technology Roadmap: Carbon Capture and Storage, 2013 Edition, page 17.
[50] The Global Status of CCS: 2013, Global CCS Institute, August 2013, page 15.

non-government organizations have an established track record of contesting projects relating to CO_2 by opposing permits and legal action. Such delays both slow progress and escalate cost of building any sequestration site and associated pipeline. For example, each month of delay in the Kemper County construction progress is estimated to add $15-25 million to the final cost.[51]

6.2 REUSE FOR ENHANCED OIL RECOVERY

The reuse of CO_2 for EOR is the most frequently cited fate for early commercial CCS projects. CO_2 has been used to increase production of oil or gas in partially depleted reservoirs for decades. The DOE estimates 250 billion tons of CO_2 can be used for EOR and thus stored, which is about 10% of the capacity estimated for deep saline sequestration.[52] The ability to broadly deploy CO_2 for EOR to support coal-fired generation across the U.S. is not apparent – the largest sites are concentrated in a limited number of states.

The following factors are relevant.

Location of Candidate Sites. DOE has increased estimates for the amount of CO_2 that can be productively used for EOR using "next generation" technologies;[53] however, there remains a strong heterogeneous distribution of sites. Certain Midwestern and Gulf Coast states may have abundant sites, but the Pacific Northwest and much of the eastern seaboard are limited. A total of 19 states either have not been assessed or feature "zero" EOR CO_2 storage capacity, or can accommodate only a small number of coal-fired generating units.

Characteristics. Similar to deep saline sequestration, the subsurface features that affect CO_2 storage and plume migration must be characterized for depleted oil and gas reservoirs. The IEA Technology road map, which cited a 5-10 year time period to characterize saline reservoirs, for EOR noted "...For projects using depleted oil and gas reservoirs or storing through EOR, this [5-10 year] lead time may become shorter, but the storage capacities are usually more limited."[54]

In summary, extensive time may be required to characterize the storage capability of depleted oil and gas reservoirs, although likely less than the minimum 5 years cited for saline reservoirs.

Pipeline. The pipeline network to deliver CO_2 from most states to an EOR site must be expanded, requiring significant investment. As of 2010, industry had expended over

[51] *Kemper County power project cost approaches $5billion with latest rise (updated),* October 29, 2013, Gulflive.com blog, available at http://blog.gulflive.com/mississippi-press-business/2013/10/kemper_county_power_project_co.html.
[52] 2012 Carbon Atlas, page 25.
[53] *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR),* Report DOE/NETL-2011/1504, June 20, 2011.
[54] Ibid, page 17.

$2.2 B for CO_2 transport pipeline over 2,200 miles within the Permian Basin alone.[55] A recent study for EPRI reported that 55 CO_2 pipelines, totaling approximately 4,700 miles, are dedicated to EOR.[56] The average length of each pipeline is 83 miles. As noted for saline reservoirs, the technical challenges to expanding the pipeline network can be overcome, but the non-technical issues – addressing property rights for right-of-way access and multi-state jurisdictions – will present equal challenges.

Surface vs. Subsurface Ownership. Not all states clearly specify surface vs. subsurface property rights – which will lead to conflicts of interest and potential litigation. It is not uncommon outside the eastern U.S. for subsurface and surface rights to be separated, a consequence of tradition stemming from the early homestead laws. There is precedent regarding surface vs. subsurface ownership rights for wastewater injection. Specifically, operators of wastewater wells have been held accountable for "trespass" of injected wastes into subsurface properties owned by others, for which rights had not been acquired. The case for CO_2 injection is unclear.

In summary, potential exists to permanently sequester or isolate CO_2 by EOR or sequestration, but uncertainties remain. Many of these uncertainties are being addressed through the DOE/NETL Regional Partnerships' eight large-scale field studies,[57] but all have operated for a small fraction of the time required to service power generation. Major investment for pipeline infrastructure is required. Uncertainties exist as to property rights to construct pipelines and subsurface ownership of pore spaces.

[55] *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long-Term Carbon Storage Solution*, Department of Energy, National Energy Technology Laboratory, page 11.
[56] PRISM 2.0: *CO_2 Pipeline Infrastructure Assessment*, EPRI Technical Update #3002000873, February 2014.
[57] 2012 Carbon Atlas, page 8.

SECTION 7

TIMELINE FOR COMMERCIALIZATION

Sections 3-5 described the status of the three means to capture CO_2, while Section 6 addressed uncertainties with respect to generalizing sequestration and enhanced oil recovery. Section 7 summarizes what must be accomplished to commercially "prove" these processes – a necessary criterion for a technology to qualify as a "best system of emissions reduction" under the NSPS.

7.1 EXISTING, PROPOSED PROJECT TIMELINE

Figure 7-1 presents a timeline for the testing, demonstration, and early commercial application of the most noted CCS project demonstrations. The timeline shows the start date for each activity and the equivalent generating capacity of the CO_2-capture step. The start date is indicated on the horizontal axis by the calendar year, and the generating capacity (MW-equivalent) of the unit on the vertical axis. Figure 7-1 distinguishes between the category of CO_2 capture technology used – either postcombustion, precombustion, or oxycombustion. The legend also identifies projects either operating, in construction, or for which financing is closed and guaranteed – these are represented by the solid or closed symbols. Projects that are proposed but not yet confirmed due to the need to secure additional partners, operating permits, or financing are identified by the open symbols.

The small pilot plant and commercial scale units, that with one exception only capture and do not store or sequester CO_2, are identified in the lower left of Figure 7-1. The planned large-scale utility demonstrations are shown on the right.

Figure 7-1 shows that with one exception – the Kemper County plant – operating experience does not begin to accrue until about 2017. In 2014 the 110 MW Boundary Dam unit is anticipated to begin operating with postcombustion control process, and Kemper County is currently scheduled to begin operating with precombustion control. The start dates are important but just that – start dates. At least two years of operation are necessary to both "shakedown" the process equipment, refine operation, and begin to accrue and synthesize data. The CO_2 capture component requires at least 2 years of operating data to deduce and refine design information. The sponsors of two oxycombustion pilot plants (10-30 MW equivalent) at Calide and Lacq recognize this, as the pilot plants operated for 2 years. A third oxycombustion pilot plant (Vattenfall) will operate for a decade to derive adequate experience.

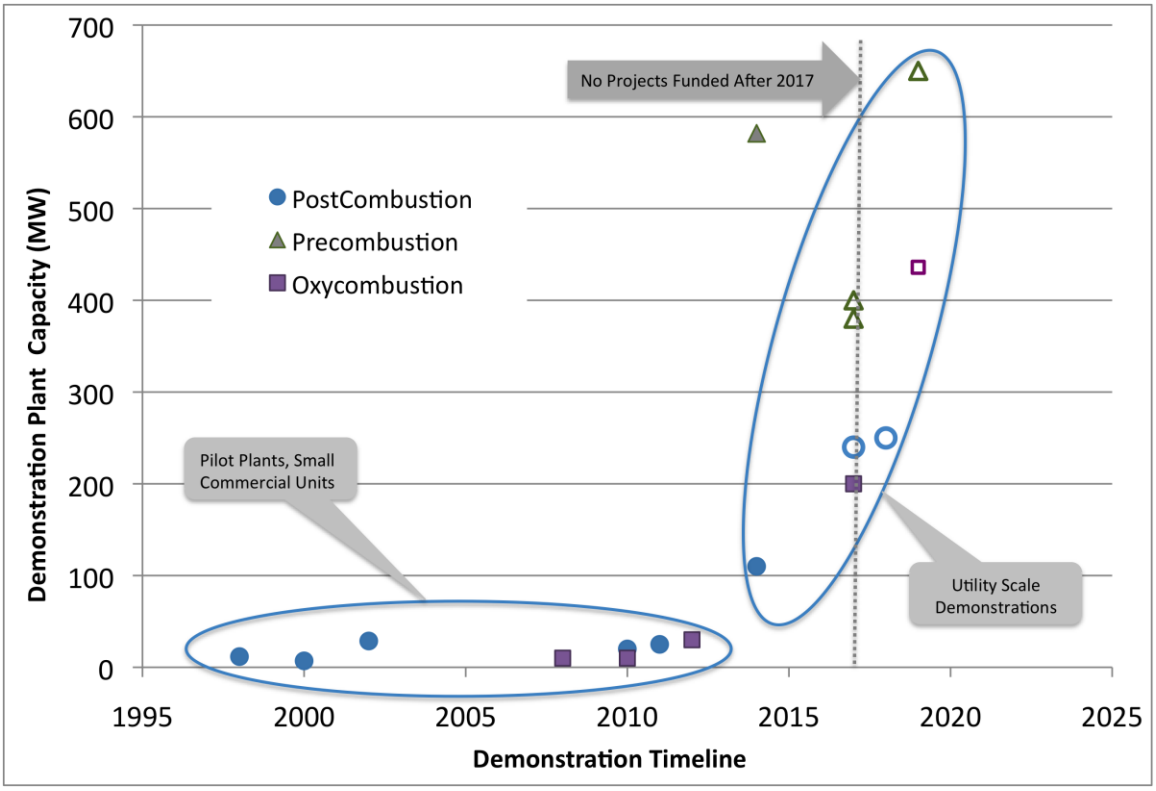

Figure 7-1. Schedule of Pilot and Demonstration Plants Employing Carbon Capture with Enhanced Oil Recovery or Sequestration. *(Note: "Closed" symbols define projects operating, under construction, or fully funded. "Open symbols define projects planned or for which financing and permits are not complete or authorized).*

The eight projects encircled and labeled Utility Scale Demonstrations – along with Kemper County – are the most relevant activities. Other than Kemper County, only two of these projects are certain – the Sask Power Boundary Dam and FutureGen 2.0 project. The remaining demonstrations for postcombustion (NRG/Parish and Maasvlakte/ROAD), precombustion (Texas Clean Energy, Hydrogen Energy California, and Don Valley), and oxycombustion (White Rose) are uncertain. Most of these projects – if actually funded and operated – will not generate data from which commercial designs can be inferred until 2017-2020. Each project is supported by government subsidy, ranging from approximately 10% (Kemper County) to almost 50% (FutureGen2.0).

A minimum of two years operation is required to synthesize data into CO_2 capture design lessons. For example, the condition of postcombustion solvents, after two years of regeneration and exposure to coal-fired gas products, should be documented. Separate from CO_2 capture, the array of sequestration issues discussed in Section 6 will require at least an additional 2-4 years of observation beyond first CO_2 injection.

7.2 GENERALIZING RESULTS FOR NATIONAL APPLICATION

Experience gained from pilot plant, demonstration, and early commercial tests shown in Figure 7-1 will be used to generalize CO_2 capture to national application. The tasks to be addressed are (a) scaling results from small units to 500 MW and greater capacity, (b) generalizing the design beyond the specific coal and site condition for any one test or demonstration, and (c) assuring the individual process components work in an integrated system. Each of these required tasks is elaborated as follows.

Scaling Design to Larger Capacities. The task of "scaling" small-scale results to large generating capacities must be addressed. The experience derived at 20-100 MW, although invaluable, requires extrapolation to larger process equipment. Understanding how to convert lessons from 20 or 100 MW pilot-scale equipment to large commercial scale is necessary.

The scale of process equipment that is required commercially is suggested by Figure 7-2, which presents the conceptual design of one proposed coal plant employing postcombustion CO_2 capture. Figure 7-2 shows, encircled in red, the steam generator and steam turbine that generate power. The process equipment adjacent to the turbine encircled in green are environmental controls for emissions such as NO_x, SO_2, particulate matter, and other species limited by the Mercury and Air Toxics (MATS) program.

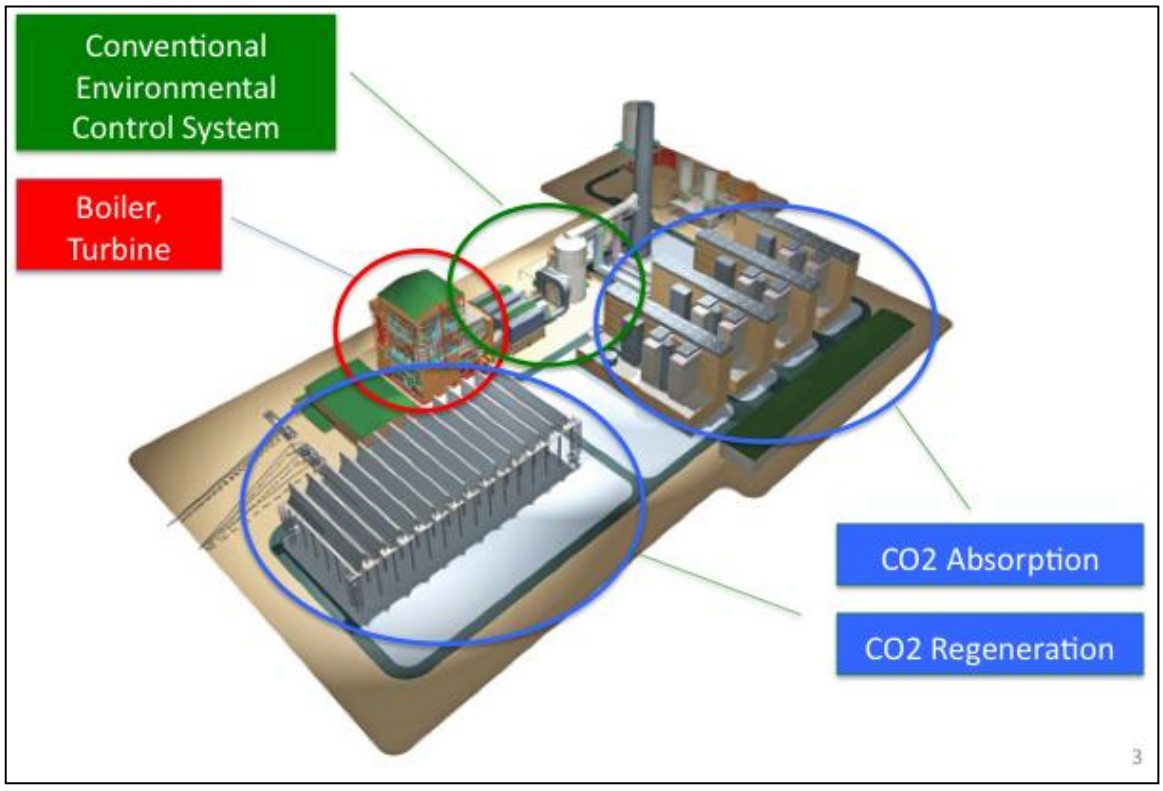

Figure 7-2. Conceptual Design of Postcombustion CO_2 Control System

Most notable is the process equipment within the blue circles that captures CO_2. Equipment both for absorption of CO_2 and byproduct generation is shown.

The equipment in Figure 7-2 represents a conceptual design for one postcombustion CO_2 concept – and does not necessarily represent precombustion or oxycombustion applications. The latter two technologies will differ in plant footprint occupied and size of equipment, but will require large control equipment.

In summary, Figure 7-2 shows the significant scale of equipment to be designed and constructed to capture CO_2.

Generalizing Design for Broad Application. Any one test or demonstration site is characterized by coal composition and site conditions, which can reflect a narrow category of applications. Extending design lessons from early tests and demonstration equipment to different fuels and sites is necessary to avail CO_2 capture technology on a broad national basis.

Coal composition – particularly inorganic material such as metal and trace elements – can affect CO_2 removal chemistry. Success with a specific coal – lignite, for example – does not guarantee success for other widely used and available coals, such as eastern bituminous or Powder River Basin. Further, the content of chlorides and fluorides is important as they affect corrosion and materials of construction – and thus cost. The fuel heat content and volatility – the latter describing the ease with which solid particles gasify when exposed to heat – are important particularly for the precombustion method.

Physical characteristics of a site such as ambient temperature, humidity, and access to water also are important to power plant and CCS performance. Water availability will likely be key in siting facilities that use either the postcombustion or precombustion control process. The water demand to service these CCS processes can be excessive – increasing demand compared to a baseline case without CCS by 50-70%.[58] At least one analyst has noted this magnitude of water demand may prohibit CCS use – and eliminate new coal-fired plants – in regions with limited water supply.[59] Water issues are further addressed in a subsequently.

In summary, generalizing equipment design for each of postcombustion, precombustion, and oxycombustion CO_2 control methods will require experience with at least the three "ranks" or categories of coal broadly used in the U.S., as well as various sites.

"Seamless" Operation of Components. A third technical challenge to be overcome is assuring the components work as an integrated system in a seamless manner. Satisfying this requirement demands compatibility between individual components and assuring

[58] *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, DOE/NETL Report 2011/1498, Revision 1 – September 19, 2013 (Original – May 27, 2011). Water use determined from water balance tables for Case 1 and Case 2 scenarios.
[59] *Energy analyst Faeth says water-intensive CCS could disqualify technology in some regions,* E&E OnPoint, November 19, 2013, viewable at http://www.eenews.net/tv/videos/1749/transcript

byproducts or residual emissions are not generated that require additional clean–up measures.

Some observers note CCS components have been adequately demonstrated in singular applications – equating this experience with a demonstrated integrated design. However, the carbon removal systems for a generating unit must co-operate with the rest of the plant to meet a variable – and at times unpredictable – load in competitive power markets. Fulfilling this need requires an integrated working system as opposed to a collection of components, even if proven successful in tests that do not reflect authentic commercial operation.

As noted, an integrated system should minimize introducing byproducts into the gas stream or liquid and solid media. A recent environmental assessment identifies nitrosamine emissions as potential byproducts of amine-based postcombustion CO_2 control.[60] These byproducts may pose health risks and require a separate, dedicated control measure for both gas and liquid effluent.[61]

This systems integration task is as important as the design of any individual component. In fact, the Global CCS Institute, in their recently released *Global Status of CCS – 2013*, note that "...the key technical challenge for widespread CCS deployment is the integration of component technologies into successful large-scale demonstration projects in new applications such as power generation...".[62]

Further, the International Energy Agency, in their technology *Roadmap for Carbon Capture and Storage: 2013* state that "…although the individual component technologies required for capture, transport, and storage are generally well understood..." the largest challenge for CCS deployment is the integration of component technologies into large-scale demonstration projects.

For example, the postcombustion process currently scheduled to start up in early 2014 – Sask Power's Boundary Dam unit – employs 125 separate subsystems.[63] Mississippi Power's Kemper County unit –scheduled for a late 2014 startup – employs an equally large number of subsystems. In summary, the need to scale, generalize, and integrate the operation of these processes requires additional demonstrations.

7.3 WATER USE IMPLICATIONS

One additional aspect of CCS is the implication for increased water use, which escalates significantly for CO_2-control power stations.

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[60] Review of Amine Emissions from Carbon Capture Systems, Version v1.1, Scottish Environment Protection Agency, January 2013. Available at *www.sepa.org.uk*

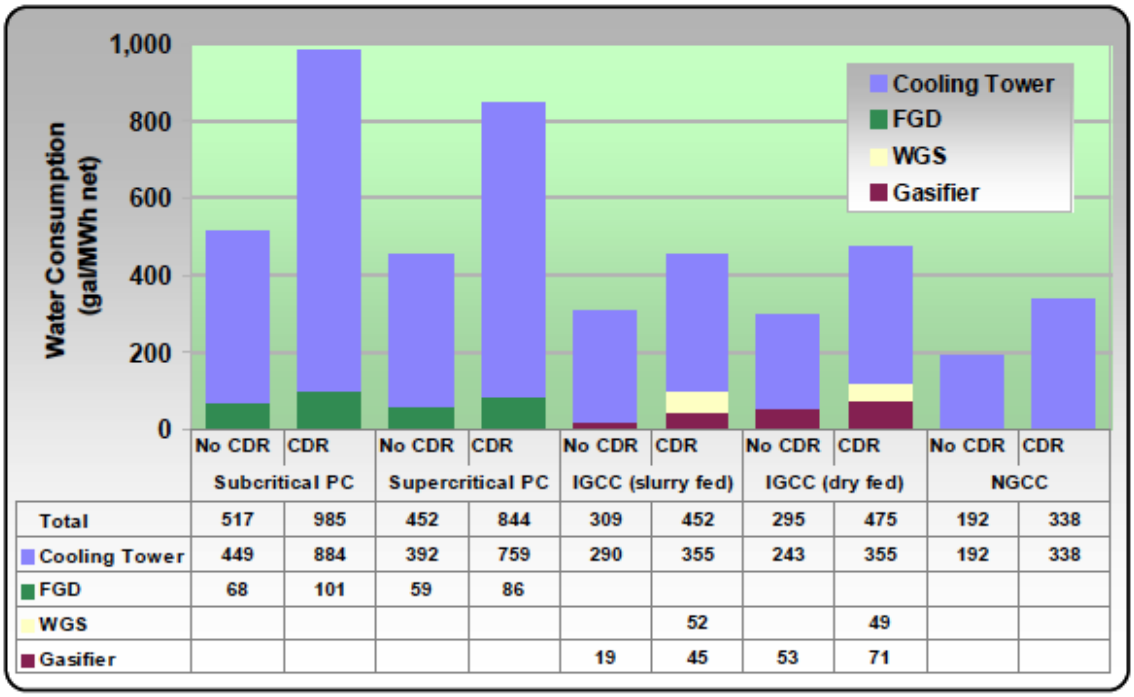
[61] Health and environmental impact of amine based post combustion CO_2 capture, Gjernes E., et al., SciVerse ScienceeDirect Energy Procedia 00 (2013) 000-000, available at www.elsvier.com/locate/procedia

[62] The Global Status of CCS: 2013, Global CCS Institute, page 10.

[63] Ball 2013.

Even without CCS, water use by fossil steam generating units raises concerns with certain stakeholders. The long-awaited ruling under Clean Water Act Section 316(b) – which may require existing plants to abandon once-through cooling – is evidence that water use is significant in evaluating electric generating unit environmental impact.

The DOE examined water use patterns of generating units equipped with CCS and concluded that plants so-equipped use appreciably more water.[64] Figure 7-3 presents DOE's estimate of water consumption per net unit output (e.g., per gal/MWh net) for subcritical pulverized coal plants, supercritical pulverized coal plants, and IGCC. (Natural gas/combined cycle generating units are included for comparison). For both subcritical and supercritical pulverized coal plants, water consumption almost doubles with the use of CCS. Electric generating units employing IGCC experience about a 30% increase in water use with CCS.



	No CDR	CDR	No CDR	CDR	No CDR	CDR	No CDR	CDR	No CDR	CDR
	Subcritical PC		Supercritical PC		IGCC (slurry fed)		IGCC (dry fed)		NGCC	
Total	517	985	452	844	309	452	295	475	192	338
Cooling Tower	449	884	392	759	290	355	243	355	192	338
FGD	68	101	59	86						
WGS						52		49		
Gasifier					19	45	53	71		

Figure 7-3. Water Consumption (gal/MWh basis) for Greenfield Plants With/Without CCS (Figure 4-2 from DOE Water Requirements)

Both CO_2 removal process requirements and the decrease in electric generating unit efficiency escalate water demand per unit net output (gal/MWh). For example, for subcritical and supercritical pulverized coal units, cooling tower water demand increases due to additional cooling required by the amine process and CO_2 compressor. For IGCC, the water gas shift reactor (WGS in Figure 7-3) comprises most of the higher water demand due to CO_2 control. The cooling system water duty also increases to support CO_2 recovery and acid gas removal units, as well as cooling CO_2 compressors.

[64] Gerdes, K., et al., *Water Requirements for Existing and Emerging Thermoelectric Plant Technologies*, DOE/NETL-402/080108, April 2008 (April 2009 Revision). Hereafter DOE Water Requirements.

7.3 COMMERCIALIZATION: ADDITIONAL PERSPECTIVES

Several organizations have offered demonstration and commercialization goals for CCS. Perhaps most notably, a major equipment supplier to the power industry presented a position on the commercial availability of CCS. In addition, four organizations have projected CCS will be commercially available by about 2020. These are the (a) Congressional Research Service, (b) International Energy Agency, (c) U.S Department of Energy, and (d) UK government. Each is addressed as follows.

7.3.1 Equipment Supplier (Alstom)

Alstom's Vice President for Power Technologies and Government Affairs, Mr. Robert Hilton, testified on March 12 to the House Subcommittee on Environment and the Subcommittee on Science, Space, and Technology. Mr. Hilton, after noting that Alstom has ten pilot plants on CCS either in operation, design, or construction worldwide, offered that "Alstom would challenge EPA on the argument that carbon capture is available and adequately demonstrated".[65]

7.3.2 Congressional Research Service

The Congressional Research Service, in an October 2013 analysis, compiled a list of organizations with a CCS commercialization goal of 2020. The CRS Report noted that experience with conventional FGD and SCR, and evolutionary control technologies such as combined NO_x/SO_2 – suggested two decades is required for commercialization.[66] The CRS did offer an opinion that postcombustion control could be the first of the options commercially proven and precede 2020 – but no specific date is offered.

7.3.3 International Energy Agency

The International Energy Agency in 2013 released its *Technology Roadmap: Carbon Capture and Storage – 2013 Edition*. A goal for 2020 recommends "…the capture of CO_2 is successfully demonstrated in at least 30 projects across many sectors...".[67] The document also presents an Action 2, which advises governments to "…develop national laws and regulations as well as provisions for multilateral finance that effectively require new-build, base-load, fossil-fuel power generation capacity to be CCS-ready."[68] The provision that new-build plants be CCS-ready is in contrast that a plant be CCS-equipped.

7.3.3 US Department of Energy

The U.S Department of Energy's National Energy Technology Laboratory's most recent *Carbon Dioxide Capture and Storage R&D Roadmap* identified DOE's goal as "...having an advanced CCS technology portfolio ready by 2020 for large-scale demonstration that provides for the safe, cost-effective carbon management that will meet our Nation's goals

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[65] Hilton, R., *Testimony Before the Hearing on Science of Capture and Storage: Understanding EPA's Carbon Rules,* sponsored by the U.S. House of Representatives Committee on Science, Space, and Technology, March 12, 2014.
[66] *Carbon Capture: A Technology Assessment, Congressional Research Service*, October 21, 2013, Report 7-5700, R41325. Page 90.
[67] *Technology Roadmap: Carbon Capture and Storage – 2013 Edition*, The International Energy Agency, 2013. See page 23.
[68] Ibid. See page 28.

for reducing GHG emissions."[69] The roadmap further calls out completing by 2020 "full-scale demonstrations of advanced oxycombustion and postcombustion CO_2 capture technologies."[70]

7.3.4 UK Government

In April of 2012 the UK Ministry for Energy and Climate Change issued a CCS Roadmap, which stated "Our aim is to enable industry to take investment decisions to build a CCS equipped fossil power plant in the early 2020s."[71] This document further describes a CCS Commercialization Programme, which states an objective of "...reducing the cost of CCS so that it can be deployed in the early 2020s."[72]

[69] *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap*, December 2010, page 3; also Figure 1-10 timeline on page 12.
[70] Ibid. Page 12, Table 1-1.
[71] *CCS Roadmap: Supporting Deployment of Carbon Capture and Storage in the UK*, April 2012, page 5.
[72] Ibid, page 26.

SECTION 8

CONCLUSIONS

The prospect of commercially proving CCS – that is, offering CCS for sale with performance supported by meaningful guarantees – cannot be assessed until at least 2020 provided current and pending pilot plants and demonstration tests proceed in a timely manner. As discussed in Section 7, the experience to evaluate just the CO_2 capture step – and to know if results can be scaled, generalized, and configured in an integrated design – will not be broadly available until 2020 and perhaps later.

Several demonstration units – Kemper County, Sask Power Hills, and FutureGen 2.0 – will provide useful data perhaps by 2017. The Great Plains Synfuels project provides experience that – although insightful to dedicated chemical co-production – is of limited value to wholesale power generation. As Dr. Julio Friedmann, Deputy Assistant Secretary for Clean Coal recently noted about CCS, "This is not a power plant; this is a carbon refinery".[73]

Evaluating the feasibility of CCS for applicability to the array of fuels and sites that typify dedicated power generation facilities in the U.S. will require broad experience. As a minimum, operating data over several years from at least the eight utility-scale projects in Figure 7-1 are necessary. Proving that CO_2 can be sequestered in saline reservoirs is equally important to effectively capturing CO_2 from flue gas. A small subset of the projects identified in Figure 7-1 will sequester CO_2 using saline reservoirs; with 2020 likely the earliest date when issues such as injection of CO_2 and monitoring plume spread can be evaluated. As noted in Section 7.3, non-technical issues such as right-of-way for CO_2 pipeline construction and transport, property rights, and surface vs. subsurface access are equally important.

The conclusion that it will take until at least 2020 to determine if CCS is commercially proven and a technology deemed "best system of emission reduction" of CO_2 is shared by other governmental and regulatory agencies. These include the U.S. Department of Energy, the International Energy Agency, and the U.K. Ministry for Energy and Climate Change.

[73] ClimateWire (Feb 28 2014).

Toward a better understanding and quantification of methane emissions from shale gas development

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Edited* by Barbara J. Finlayson-Pitts, University of California, Irvine, Irvine, CA, and approved March 12, 2014 (received for review September 4, 2013)

The identification and quantification of methane emissions from natural gas production has become increasingly important owing to the increase in the natural gas component of the energy sector. An instrumented aircraft platform was used to identify large sources of methane and quantify emission rates in southwestern PA in June 2012. A large regional flux, 2.0–14 g CH_4 s^{-1} km^{-2}, was quantified for a ∼2,800-km^2 area, which did not differ statistically from a bottom-up inventory, 2.3–4.6 g CH_4 s^{-1} km^{-2}. Large emissions averaging 34 g CH_4/s per well were observed from seven well pads determined to be in the drilling phase, 2 to 3 orders of magnitude greater than US Environmental Protection Agency estimates for this operational phase. The emissions from these well pads, representing ∼1% of the total number of wells, account for 4–30% of the observed regional flux. More work is needed to determine all of the sources of methane emissions from natural gas production, to ascertain why these emissions occur and to evaluate their climate and atmospheric chemistry impacts.

unconventional gas | greenhouse gas | hydraulic fracturing

Methane is a very important component of the Earth's atmosphere: it represents a significant component of the natural and anthropogenically forced greenhouse effect, with a global warming potential 28–34 times greater than CO_2 using a 100-y horizon and even greater on shorter time scales (1, 2). It also is an important sink for the hydroxyl radical, the dominant agent that defines the atmosphere's cleansing capacity (3), has a significant impact on tropospheric ozone, and is one of the important sources of water vapor in the stratosphere, which in turn impacts stratospheric ozone and climate (4). The recent observation that global methane concentrations have begun increasing (5), after a decade of static or decreasing emissions in the late 1990s to ∼2007, has renewed interest in pinpointing the causes of global methane trends. Recently natural gas has been explored as a potential bridge to renewable energy, owing in part to the reduction in carbon emissions produced from electricity generation by natural gas compared with coal (6–9). Advances in drilling and well stimulation techniques have allowed access to previously locked reservoirs of natural gas, such as the Marcellus shale formation in Pennsylvania, which has led to a boom in natural gas production in the last decade (10). This has led to estimations of the carbon footprint of natural gas to examine the impact of increasing our reliance on natural gas for various energy needs (11–16). An important unresolved issue is the contribution of well-to-burner tip CH_4 emission to the greenhouse gas footprint of natural gas use. Given that CH_4 is a much more potent greenhouse gas than CO_2, quantifying CH_4 emissions has become critical in estimating the long- and short-term environmental and economic impacts of increased natural gas use. According to a recent study, if total CH_4 emissions are greater than approximately 3.2% of production, the immediate net radiative forcing for natural gas use is worse than for coal when used to generate electricity (8).

The first estimates for CH_4 emissions from shale gas development were reported in late 2010 and are based on uncertain emission factors for various steps in obtaining the gas and getting it to market (17, 18). In the short time since these first estimates, many others have published CH_4 emission estimates for unconventional gas (including tight-sand formations in addition to shales), giving a range of 0.6–7.7% of the lifetime production of a well emitted "upstream" at the well site and "midstream" during processing and 0.07–10% emitted during "downstream" transmission, storage, and distribution to consumers (reviewed in refs. 18 and 19). The highest published estimates for combined upstream and midstream methane emissions (2.3–11.7%) are based on actual top-down field-scale measurements at specific regions (20, 21). Whereas a recent shale gas study (22) based on field sites across the United States to which the authors were given access scaled actual measurements up to the national level and found lower emissions than US Environmental Protection Agency (EPA) estimates, an equally recent study (23) used atmospheric measurements of greenhouse gases across the United States to inform a model and found CH_4 emissions, cumulatively and specifically from fossil fuel production activities, to be underestimated by the EPA.

The current range of observed CH_4 emissions from US natural gas systems (2.3–11.7%), if it were representative of the national scale, applied to the reported 2011 unassociated gas production number yields a range of CH_4 emissions between 5.6 and 28.4 Tg

Significance

We identified a significant regional flux of methane over a large area of shale gas wells in southwestern Pennsylvania in the Marcellus formation and further identified several pads with high methane emissions. These shale gas pads were identified as in the drilling process, a preproduction stage not previously associated with high methane emissions. This work emphasizes the need for top-down identification and component level and event driven measurements of methane leaks to properly inventory the combined methane emissions of natural gas extraction and combustion to better define the impacts of our nation's increasing reliance on natural gas to meet our energy needs.

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The authors declare no conflict of interest.

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CH_4, whereas the EPA reports 6.7 Tg CH_4 from natural gas systems in 2011 and only 28 Tg CH_4 total anthropogenic emissions (24). Natural gas systems are currently estimated to be the top source of anthropogenic CH_4 emission in the United States, followed closely by enteric fermentation, but the top-down observations suggest that natural gas may play a more substantial role than previously thought (24). Inadequate accounting of greenhouse gas emissions hampers efforts to identify and pursue effective greenhouse gas reduction policies.

Although it is clear that analysis of the effect of natural gas use would benefit from better measurements of emissions from unconventional gas wells, the inaccessible and transient nature of these leaks makes them difficult to identify and quantify, particularly at a scale at which they are useful for bottom-up inventories or mitigation strategies (i.e., leak rates of individual components or activities). Previous techniques have used either bottom-up inventories of the smallest scale of contributions or top-down apportionment of observed large-scale regional enhancements over a complex area to identify the source of the enhancements (11, 17, 20–23, 25). Although the latter suggest that the leak rate may be higher than what bottom-up inventories have allocated, they give little to no information about where in the upstream production process these leaks occur, thus hampering the interpretation of these data for bottom-up inventories or mitigation purposes.

Here we use an aircraft-based approach that enables sampling of methane emissions between the regional and component level scales and can identify plumes from single well pads, groups of well pads, and larger regional scales, giving more information as to the specific CH_4 emission sources. We implemented three types of flights over 2 d in June 2012: investigative (I), mass-balance flux (MB), and regional flux (RF). Details of each flight are presented in Table 1. Our results indicate a large regional CH_4 flux in southwestern PA. We show that the methane emission flux from the drilling phase of operation can be 2 to 3 orders of magnitude greater than inventory estimates, providing an example and improved understanding of the differences between observed data and bottom-up inventories.

Results and Discussion

We conducted measurements in southwestern PA in the Marcellus shale formation region in June 2012. For two morning flights we calculated a regional flux of 2.0–13.0 g CH_4 s^{-1} km^{-2} for RF-1 over a box that approximates the size of our flight path (dashed box in Fig. 1) that we define as the original sampling area (OSA) and 2.0–14.9 g CH_4 s^{-1} km^{-2} for RF-2. These ranges represent our analysis of the combined effect of all sources of uncertainty, which is dominated by the range of accumulation time scales over which the enhancement may have occurred (i.e., a maximum of 18 h commencing with the time of collapse of the boundary layer the day before, to a minimum of 5–6 h for air to flush through the sampling area). These estimates are not statistically different from the range of estimates obtained by summing up bottom-up emissions

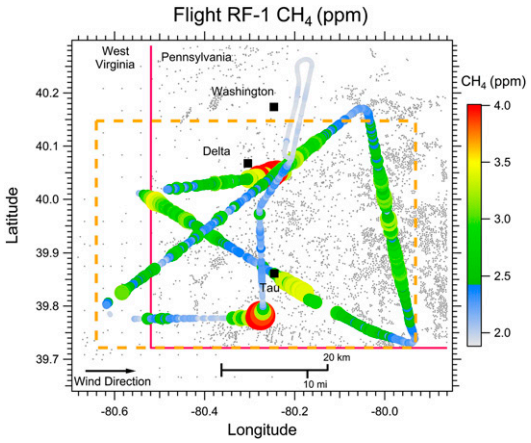

Fig. 1. Regional enhancement of methane at 250 m AGL on the morning of June 20th. The dashed orange box represents the OSA, 2,844 km^2, and the gray dots show well locations.

estimates for oil and gas development, coal mining, and other sources for the OSA depicted by the dashed orange box in Fig. 1 (corresponding to a ∼6-h time scale) and for the 18-h upwind accumulation area (UAA) shown in Fig. S1: 2.3–4.6 g CH_4 s^{-1} km^{-2}. Methane emissions from natural gas contribute 22–62% of the estimated bottom-up flux in this region. Using our top-down flux measurements, the assumed range of methane from natural gas contribution (22–62%), and industry reported production rates, we estimate a possible range for the fugitive methane emission rate of 2.8–17.3% of production in this region, which applies only to these two specific study dates.

It is important to note that we could find no evidence from state records or from our analysis of photographs taken during flights of wells in flowback after hydraulic fracturing in the area during the sampling time (discussed in *SI Text*). Flowback is the period after fracturing when a portion of the fracturing fluid used returns up the wellbore, flushing out with it substantial amounts of natural gas. We used data submitted voluntarily by oil and gas operators to FracFocus.org to identify one potential flowback event (for a pad not sampled in this study) and included the emissions in our bottom-up inventory. We would expect the regional emission rate to be greater if more wells were in flowback (11, 17, 18).

Although our top-down and bottom-up flux estimates are not statistically different, the top-down flux estimate encompasses a range of larger magnitude fluxes compared with the bottom-up method, and the upper limit for the fraction of production emitted is large enough to provide ample motivation to pursue investigation of possible significant methane emission processes not included in the bottom-up inventory. To quantify emission rates from significant sources of CH_4 emissions in this shale gas

Table 1. Meteorological conditions and time duration of each aircraft flight experiment

Flight type	Flight no.	Date	Start time (EDT)	Duration, min	Wind speed, m/s	Wind direction
RF	1	6/20/2012	10:00	96	3.0	276
RF	2	6/21/2012	8:55	89	3.7	270
MB	1	6/20/2012	11:55	30	3.1	236
MB	2	6/20/2012	15:15	56	3.3	239
MB	3	6/21/2012	16:00	60	5.5	252
MB	4	6/21/2012	14:05	73	4.7	226
I	1	6/20/2012	12:25	5	3.0	258
I	2	6/21/2012	15:22	6	4.7	227
I	3	6/21/2012	9:14	15	4.2	257

Flights are classified into three flight types: RF, MB, and I (defined in text). Investigative flights were short and occurred between and during the longer RF and MB flights. Flights are identified by their flight type and flight number (e.g., RF-1, MB-3, etc.). Note that flights MB-1 through MB-3 are near pad Delta and flight MB-4 is near pad Tau.

drilling region we conducted mass-balance flights (MB-1–MB-4) for well pads with observed enhancements large enough to use the aircraft-based mass-balance technique, as described in ref. 26. In the region between Washington, PA and south to the border of WV we observed multiple high concentration methane plumes and investigated two areas where initial observations revealed well pads with potentially high methane emission rates. The high density of pads in this region and the prevailing wind direction (SW) during the time of measurement combined to make plume attribution to single pads difficult. In cases in which fluxes from individual pads could not be isolated, we averaged the calculated flux from a wider region over the number of pads that could have possibly contributed. Fig. 2 shows the downwind methane concentrations in a vertical plane perpendicular to the mean wind direction from an isolated pad designated "Delta" (shown in Fig. 1 near the northern hotspot). Attribution of the flux to that (or any specific) source involved maneuvering in a circular pattern around the prospective source, with observed enhanced methane concentrations only on the downwind side, as shown in Fig. S2. Fig. 3 shows the downwind methane concentrations that include signal enhancement from a pad "Tau" (shown in Fig. 1 near the southern hotspot), as well as from other upwind pads, coal-bed methane wells, and a significant plume from an adjacent coal mine. The high density of potential upwind sources around Tau made attribution to specific sources impossible, although it is probable that some of this flux comes from at least one pad in the drilling stage (Tau). Combining results of MB-1 thru MB-3 yielded an average of 236 g CH_4 s^{-1} per pad for seven high emitting pads, corresponding to 34 g CH_4 s^{-1} per well. Individual MB flight results are presented in Table 2. Note that these seven pads, with ~40 wells, representing approximately 1% of the wells in the 2,844-km^2 OSA region, contributed a combined emission flux of 1.7 kg CH_4 s^{-1}, equal to 4.3–30% of our top-down measured flux.

The methane emissions from the gas wells reported in Table 2 are surprisingly high considering that all of these wells were still being drilled, had not yet been hydraulically fractured, and were not yet in production. The Pennsylvania Department of Environmental Protection (27) confirmed that total vertical depth had not yet been reached in these wells at the time of the sampling, and our photographic evidence recorded equipment typical during the drilling phase, as shown in Fig. S3. Because of the large number of wells in our study region we were not able to review all well files to determine the total number of wells being drilled during the time of study. EPA greenhouse gas inventories report a total of 51.3 kg CH_4 per well from the entire drilling period that typically lasts 2 wk (24). Using, as limits, a 2-wk and a 2-d (the duration of our observations) drilling phase time scale, this leads to an estimated flux of 0.04–0.30 g CH_4 s^{-1} per well, 2 to 3 orders of magnitude lower than our observed average flux per well (for the high emitters we studied) of 34 g CH_4 s^{-1}. Although we only quantitatively sampled pads where we saw significant enhancement above the background, it is important to note

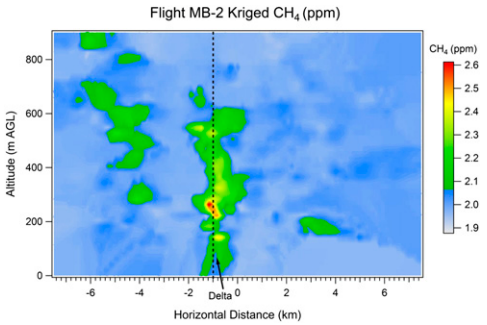

Fig. 2. Interpolated methane concentration ~1 km downwind of pad Delta, showing isolated methane plume near the center of the transect.

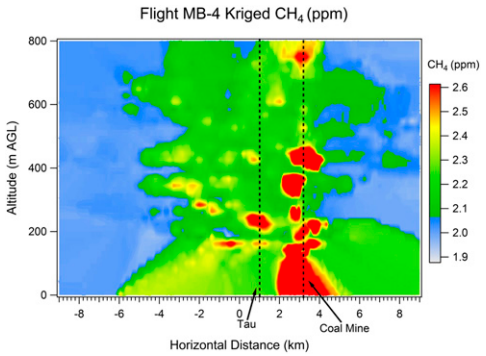

Fig. 3. Interpolated methane concentration from several pads near pad Tau. A distinct methane plume from a nearby coal mine occurs around 3 km.

that we could detect little to no emission from many other pads, particularly in the region north of the OSA, from Washington north to Pittsburgh. Thus, we do not intend for our regional flux estimate to be taken as necessarily representative of the Marcellus as a whole but only for the region defined as the OSA for these days. We also note that some sources were too intermittent to determine a flux via the aircraft mass-balance method. At a compressor station north of Washington we observed methane concentrations up to 45 ppm, but there was no consistent plume between consecutive passes downwind of the station.

Bottom-up emission factor studies usually assume no emission from gas wells during this prehydraulic fracturing period (11–16). Release from gas kicks—gas entry into the wellbore during vertical drilling despite efforts to keep the wellbore at a higher pressure than surrounding rock, a technique known as overbalanced drilling—is one possible explanation. However, it is generally assumed that gas kicks are not significant emission sources and are transient (28), although we observed comparable emissions on consecutive days. Alternatively, underbalanced drilling methods may have been used on these wells, where lower pressure in the wellbore allows fluids and gas from the various geological formations (i.e., coal deposits) being drilled through to seep into the wellbore and up to the surface, resulting in emission of hydrocarbons, including methane, during the drilling phase if the emissions are not contained or flared (28). Note that although these well pads were not permitted as coal bed methane wells the entire southwest region of Pennsylvania contains underlying coal deposits. The underbalanced drilling hypothesis is supported by aerial pictures that show a lack of a shale shaker or mud pits at these sites that are typically used in overbalanced drilling. Whatever the source of high emissions from the pads we identified as in the drilling stage, these emissions, equaling 0.6g CH_4 s^{-1} km^{-2}, are not included in our bottom-up estimate (or any other bottom-up estimate). The addition of this emission to our bottom-up inventory would shift the estimates slightly higher, but because our original results were not statistically different owing to the large range of estimates from our top-down approach, our conclusions are no different.

During the morning RF-2 flight we acquired whole-air samples using the National Oceanic and Atmospheric Administration (NOAA) programmable flask package, which were analyzed for hydrocarbons and CH_4. We found that relative to other studies of shale-well natural gas, the air samples in this region exhibited much lower mole ratios of propane and n-butane to methane, at 0.007 ± 0.001 and 0.0018 ± 0.0003, respectively. Previous reports indicate molar ratios of ~0.05 for propane (28, 29) and ~0.01 for n-butane (30). However, the observed n-butane to propane ratio, 0.27 ± 0.01, is very similar to values reported in previous work, which average 0.24 (31). These findings suggest that the shale natural gas signal is being diluted by an essentially pure CH_4 source. Although this is not the only possibility, these results support the hypothesis that the methane plumes derive from underbalanced drilling methods as wells are drilled through

Table 2. Results from four MB experiments and the number of pads and wells contributing to the flux

Flight	Flight MB-1	Flight MB-2*	Flight MB-3	Flight MB-4	Average ± σ
Total flux (g CH_4/s)	380	248	1,880	1,490	—
Total pads contributing	2	1	7	—	—
Flux (g CH_4/s) per pad	190	248	269	—	236 ± 41
Total permitted wells	15	8	41	—	—
Flux (g CH_4/s) per well	25	31	46	—	34 ± 11

Flights 1–3 were conducted near pad Delta and flight 4 near pad Tau. Flux per pad and per well is obtained by dividing the total flux by either the total number of pads or total number of wells.
*Isolated pad Delta.

formations such as shallow coal pockets producing coal-bed methane during the drilling phase. Coal-bed methane is typically composed of very high percentages of CH_4 (~98%), with trace heavier hydrocarbons (32).

Conclusions

This work shows that it is possible to interrogate and quantify emissions from individual pads and pad clusters at scales relevant to bottom-up inventories and mitigation strategies and to estimate the emission rate for a region encompassing a large number of well pads using the aircraft measurement approach. The range of regional leak rates found here for the OSA (3–17%) is similar to leak rates found by recent studies across the United States in the CO Denver-Julesburg Basin (20) and the UT Uintah Basin (21). Additionally, although a leakage rate was not calculated, a study over large areas of TX, OK, and KS (25) found surprisingly high methane emissions, indicating that high fugitive emission rates are likely to be a national-scale issue, although the mechanisms of these fugitive leaks may be different at each site. Although a recent study (22) found production sites, to which they were given access, to be emitting less CH_4 than EPA inventories suggest, these regional scale findings and a recent national study (23) indicate that overall sites leak rates can be higher than current inventory estimates. Additionally, a recent comprehensive study of measured natural gas emission rates versus "official" inventory estimates found that the inventories consistently underestimated measured emissions and hypothesized that one explanation for this discrepancy could be a small number of high-emitting wells or components (33).

These high leak rates illustrate the urgent need to identify and mitigate these leaks as shale gas production continues to increase nationally (10). The identification presented here of emissions during the drilling stage 2 to 3 orders of magnitude larger than inventory estimates indicates the need to examine all aspects of natural gas production activity to improve inventory estimates and identify potential opportunities for mitigation strategies and that top-down measurements provide an important complement to bottom-up inventory determinations. Shale gas production is expected to increase globally as many shale gas plays are starting to be explored (34). If a midrange value of the reported fraction of production that is emitted, 7%, is applied to the projected global peak shale gas production rate, 23 trillion ft^3 per year (34), it would correspond to 24 Tg CH_4 emitted per year, or ~4% of the current global total (natural and anthropogenic) CH_4 emission rate (35). Further studies are needed to enable better understanding of the operational details that lead to the largest emissions, how they might be better controlled, and to provide a more detailed picture of the expected life cycle-integrated emissions from unconventional gas wells.

Table 3. Total expected emissions from all sources and percent contribution to the total emission for the OSA and the UAA using Howarth et al. (11) emission factors and for the OSA using NETL (16) emission factors

Area	Source	Expected emissions, g CH_4 s^{-1} km^{-2}	Contribution, %
OSA (Howarth EFs)	Natural gas	0.85 (low)–2.23 (high)	21.9–42.0
	Oil	0	0
	Coal	2.96	55.7–76.3
	Flowback	0.05–0.10	1.3–1.9
	AFO	0.015	0.3–0.4
	Other	0	0
	Total (average)	3.88–5.31 (4.60)	
UAA (Howarth et al. EFs)	Natural gas	0.76 (low)–1.70 (high)	42.0–61.6
	Oil	0	0
	Coal	1.01	36.6–55.8
	Flowback	0.01–0.02	0.6–0.7
	AFO	0.015	0.5–0.8
	Other	0.019	0.7–1.0
	Total (average)	1.81–2.76 (2.29)	
OSA (NETL EFs)	Natural gas	1.41	31.4–31.8
	Oil	0	0
	Coal	2.96	65.9–66.7
	Flowback	0.05–0.10	1.1–2.3
	AFO	0.015	0.3
	Other	0	0
	Total (average)	4.42–4.49 (4.46)	

AFO, animal feeding operation; EFs, emission factors; NETL, National Energy Technology Laboratory.

Table 4. Natural gas portion of the top-down flux as a percentage of the unassociated natural gas production rate

	18-h Estimate		5 to 6-h Estimate	
Parameter	Low	High	Low	High
Top-down flux, g CH_4 s^{-1} km^{-2}	2.0	4.2	6.6	14.0
CH_4 from natural gas, %	22	62	22	62
Natural gas production rate, g CH_4 s^{-1} km^{-2}	15.9		50.1	
Natural gas flux/ production rate, %	2.8	16.4	2.9	17.3

Methods

Measurements were conducted between June 18, 2012 and June 21, 2012 over southwestern PA using Purdue's Airborne Laboratory for Atmospheric Research, a modified Beechcraft Duchess aircraft. This aircraft is equipped with a 50-Hz Best Air Turbulence probe, described by ref. 36, that measures wind vectors and pressure, a 50-Hz microbead thermistor that measures temperature, a 50-Hz global positioning system/inertial navigation system, and a 0.5-Hz high precision Picarro CO_2/CH_4/H_2O cavity ring down spectrometer (CRDS). The CRDS has ~0.05% (1 ppb) precision for methane determined during in-flight calibration, and comparable accuracy, using three NOAA Earth System Research Laboratory tanks with CH_4 concentrations of 1.8030, 2.2222, and 2.5995 ppm. A programmable flask package (PFP) provided by NOAA for whole-air sampling was also installed on the aircraft. The PFP consists of 12 flasks that hold air pressurized to 2.7 atm in 0.7-L bottles. Flasks are analyzed for 55 species, including CH_4, and hydrocarbons, by NOAA.

We calculated a regional flux on two mornings by integrating the enhancement in CH_4 above the background in the OSA (enhancement area of 2,844 km^2). The height of the box was defined as the boundary layer height, which was determined from the earliest [~10:00 AM Eastern Daylight Time (EDT)] vertical profiles of potential temperature, H_2O, CH_4, and CO_2. Boundary layer heights were observed to be 370 m above ground level (AGL) for flight RF-1 and 500 m AGL for flight RF-2 and assumed to be constant during the data collection period for each flight. The raw CH_4 data from flight at a constant altitude (~250 m AGL) around the area of interest was interpolated using the EasyKrig3.0 program (37). For RF-1 the observed concentrations are presented in Fig. 1, and the flight data for RF-2 are shown in Fig. S4. The 2D interpolation output was turned into a 3D matrix of CH_4 values by assuming the CH_4 concentration decreased linearly with height up to the boundary layer top, with background concentrations of 1.89 ppm CH_4. This assumption was based on the observed vertical profiles that depict an approximately linear decrease of the CH_4 mole ratio with altitude. We compared integration of CH_4 under the actual vertical profile and a linear regression of the vertical profile, shown in Fig. S5, and found less than a 7% difference, which supports use of the linear approximation for the whole study region. Fig. S5 shows a vertical profile obtained during flight RF-1 at ~10:00 AM EDT. The profile extends into the residual layer above the stable boundary layer. The residual layer represents well mixed (i.e., clean, air from the previous day as the boundary layer collapsed and is used to estimate the CH_4 background concentration, 1.89 ppm on both days). The CH_4 enhancement was then calculated by removing the background value and converting to mol·m^{-3}. Multiplying the enhancement by the pixel volume, 29,386.5 m^3 (171.6 m longitudinal•171.25 m latitudinal•1 m vertical), and integrating over all pixels in the sample area produces the total enhancement in moles, which can be converted to units of g or kg. To obtain a flux, the enhancement was then divided by a chosen time scale, discussed below, and divided by the total area of the OSA, 2,844 km^2, to obtain the flux in g $s^{-1}km^{-2}$.

Uncertainty was assessed by examining the range of reasonable assumptions to calculate the CH_4 enhancement and the time scale of the accumulation. A simpler CH_4 enhancement estimate was done by assuming a spatially uniform CH_4 enhancement in the box taken from the observed CH_4 vertical profile after it had been smoothed. The CH_4 enhancement differed by approximately ±30% using this technique. In addition, the effect of background CH_4 estimate was quantified by using reasonable upper limits in background concentration from background air observed in the southwest and west of the OSA during both flights, which was generally higher than the concentrations observed in the residual layer. We estimate the upper limit to the background concentration to be 2.00 ppm. In this scenario a 20% difference in the calculated CH_4 enhancement is observed. The time scale was changed to reflect different possibilities for accumulation. The lower limit to the accumulation time scale used (6 h for RF-1, 5 h for RF-2) was the time for the observed winds to flush the box. The flush time of the box represents the physical minimum time for enhanced air to be replaced with assumed cleaner upwind air, at the observed wind speeds. This assumption is supported by the observation that both RF-1 and RF-2 show cleaner air in the upwind area at the time of flight (W corner of the OSA box; Fig. 1 and Fig. S4), consistent with much smaller density of wells, as can be seen in Fig. 1 and Fig. S4. The longest time scale used (18 h) represents the time from the collapse of the boundary layer the day before (~6:00 PM) to the time observations were made. These component uncertainties are then propagated to produce the total range of the flux estimate.

A complicating factor affecting our ability to directly compare the top-down flux estimate with the bottom-up inventory is the influence of advective transport. At night, surface winds are typically low and unsustained, leading to very slow transport of air masses, and winds on the morning of our flights were low (2–3 m/s). However, for an 18-h accumulation, it is likely that these observations include mixing with air containing emissions (and/or cleaner air) from a region upwind (SW) of the measurement region. To investigate the potential impact of the upwind area we used the NOAA Hybrid Single Particle Lagrangian Integrated Trajectory Model (HYSPLIT) to predict the maximum size of the upwind area (ready.arl.noaa.gov/HYSPLIT.php). Starting at the time of observations (10:00 AM EDT) we ran an 18-h matrix back trajectory encompassing the area of observations. The 18-h time scale was chosen because it presents the largest estimate of potential upwind influence. We chose the isobaric mode with an effective altitude that is constant at 50 m to represent transport within the stable surface layer. The resulting area of influence, which we call the UAA, covers 14,597 km^2 and is shown in Fig. S1. This area is five times larger than the original sample area. An appropriate comparison with a bottom-up inventory will, therefore, have to include an estimate for an area encompassing the entire 18-h back trajectory region (UAA) and an estimate for the OSA. The average emissions over the UAA corresponds to a lower limit for the bottom-up flux, because the top-down measurements likely did not sample completely mixed air, and in this case the upwind area contains cleaner air, which dilutes the emissions. Likewise, the OSA represents an upper limit for comparison with the bottom-up flux because the top-down measurements similarly did not sample air exclusively influenced by the OSA (which has a higher density of emission sources), and accumulation may have effectively occurred over a time scale greater than the estimated 5–6 h.

Bottom-up inventories including energy sector, agriculture, landfill, and other miscellaneous emissions were produced for both the OSA and the UAA and are described in *SI Text*. Energy sector emissions were computed using the following national and state databases: Pennsylvania Department of Environment databases of oil, gas, and coal production and locations; West Virginia Department of Environment databases of oil, gas, and coal production and locations; Ohio Department of Natural Resources databases of oil, gas, and coal production; Energy Information Administration databases of state to state pipeline transmission and location; Department of Labor database of Employment and Production; and the Pipeline and Hazardous Material Safety Administration database of pipeline transmission. Default gas compositions were used (38), and all conversions between volume and mass assume standard gas conditions: 15 °C and 1 atm. Emission factors from ref. 11 are used to calculate routine fugitive emissions from natural gas production and processing and for life cycle fugitive emissions from coal and oil energy sectors. Emissions from natural gas transmission and distribution and well flowback events are calculated from emission factors provided in refs. 16 and 17, respectively. For comparison, a bottom-up inventory of natural gas sector emissions using only ref. 16 emission factors was also completed for the OSA. Methane emissions from the agriculture sector were calculated from total animal counts in the counties of interest (39) multiplied by methane emission factors from refs. 40 and 41. Other methane emissions were included from EPA-reported greenhouse gas emissions from landfills and other miscellaneous sources (42). Table 3 shows the total emissions from the bottom-up inventory for the OSA and UAA, as well as the comparison inventory for the OSA. More detailed emissions are presented for the OSA in Table S1 and the UAA in Table S2.

The comparison of uncaptured natural gas emissions as a percentage of total natural gas produced has been used as a standard of comparison between studies. We used the bottom-up inventories to compute the proportion of our observed top-down flux that would be expected to come from the natural gas sector. As shown in Table 3, the total contribution of methane emissions from the natural gas sector is assumed to be between 22% and 62% in this region. This range was used to calculate the contributing portion of natural gas emissions from the extrema in the top-down flux to be divided by the local unassociated production rates of 50.1 g CH_4 s^{-1} km^{-2} for the OSA and 15.9 g CH_4 s^{-1} km^{-2} for the UAA, as shown in Table 4. We report emission rates in Table 4 and estimate a fugitive emission rate between 2.8% and 17.3% of natural gas production for this region on these particular days. This estimate should be compared with other estimates with caution because these estimates generally use more comprehensive temporal data (16, 17, 19, 20).

Nevertheless, the upper range of this emission rate is surprisingly high, particularly because there were no major or widespread activities such as flowback events or well workovers of which we are aware that are typically associated with higher methane emission rates.

The mass-balance technique used here is described in ref. 26. Briefly, CH_4 concentration data are collected at varying altitudes downwind of a source approximately perpendicular to the prevailing wind direction. Downwind transects were flown to the top of the boundary layer, determined from vertical profiles of potential temperature, H_2O, CH_4, and CO_2, or more commonly, until the signal reached background levels. The observation of plumes that did not extend all of the way to the boundary layer top is attributed to the fact that downwind transects were typically flown 2–5 km downwind of a source, corresponding to too short a transport time scale for complete vertical mixing but necessary to isolate sources in a landscape with a dense distribution of potential sources. Fig. S6 shows raw CH_4 transect data 1.1 km downwind of pad Delta during flight MB-2. Interpolation of the raw transect data to create a 2D matrix of CH_4 values was done using EasyKrig3.0 (37). Fig. 2 shows the output from the interpolation of the raw data in Fig. S6. After the interpolated CH_4 and horizontal wind matrices are obtained, the flux is calculated according to Eq. **1**.

$$F = \int_0^{z_i} \int_{-x}^{x} \Delta[CH_4]_{ij} \times M_{\perp_{ij}} dxdz \qquad [1]$$

Here the limit z_i is the top of the boundary layer, or the height at which the plume stops, and the limits x and $-x$ are the horizontal limits determined from an arbitrary reference point in the middle of the transects. ΔCH_4 is obtained by converting CH_4 concentrations from ppm to mol·m^{-3} using measured temperature and pressure, then subtracting an average background CH_4 value, calculated by averaging the edges of the interpolated matrix, from each point in the interpolated CH_4 matrix, denoted by the subscripts ij. $M_\perp$ is the component of the mean wind that is perpendicular to the plane downwind of the source, which has also been interpolated from observations. Integrating across x and z and multiplying by dx, 110 m, and dz, 20 m, gives the flux in mol/s per cell, which can then be converted to units of g/s or kg/s. In cases in which there were multiple well pads contributing, the number of potential upwind pads was determined from visually inspecting the CH_4 data and spatial distribution of pads in the upwind direction.

Hydrocarbon concentration values were obtained from flask samples taken during flight RF-2. Of the 12 flasks, 2 were sampled in the free troposphere and excluded from hydrocarbon ratio calculations. The lowest hydrocarbon mole ratios in a single flask within the boundary layer were used as an estimate of background values and subtracted from the remaining nine flasks to obtain delta hydrocarbon values. The least-squares regression, forced through zero, between delta values of hydrocarbons, was used to find the hydrocarbon ratio. The uncertainty in the ratio reported is the uncertainty in the least-squares regression slope.

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LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

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Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a] Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b] Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c] Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d] Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e] Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in

temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

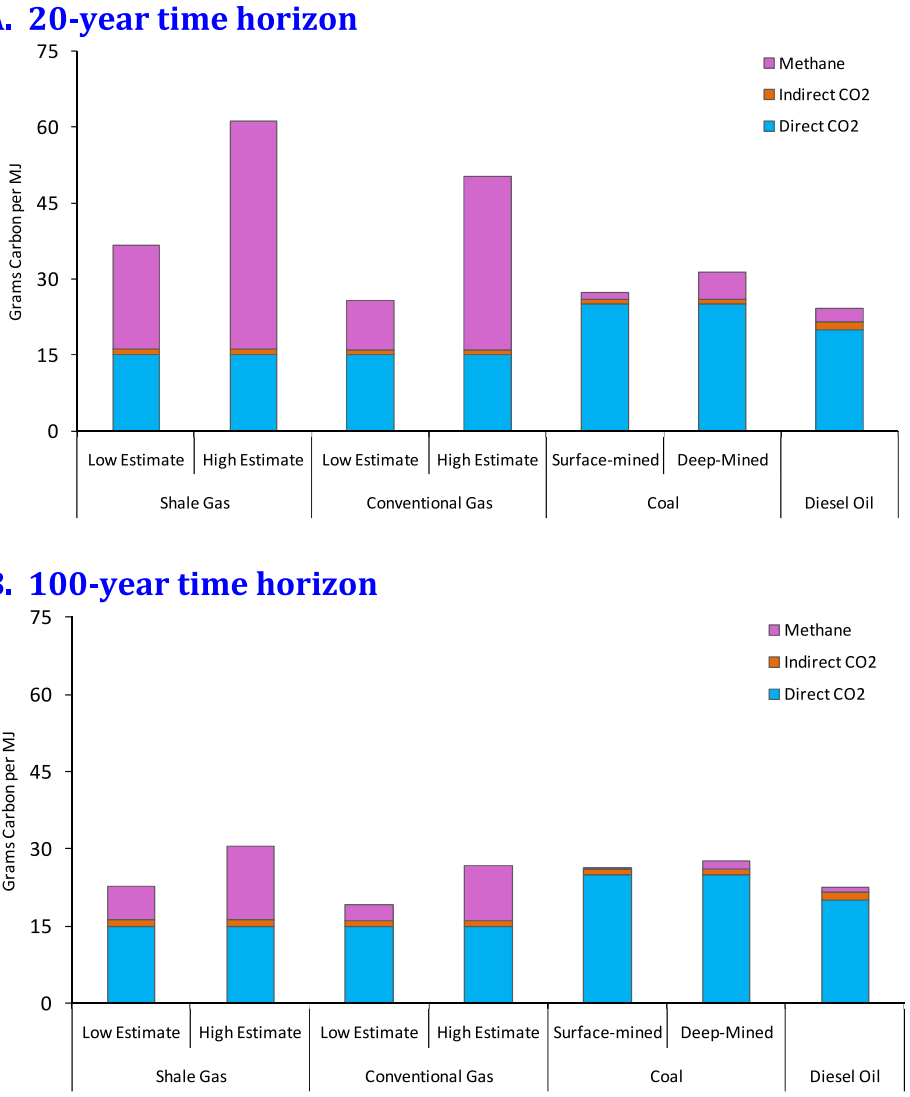

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly

reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

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A CRITIQUE OF THE SEPTEMBER 2013 REGULATORY IMPACT ANALYSIS CONCLUSION: COAL-FIRED POWER NOT COMPETITIVE WITH NATURAL GAS COMBINED CYCLE POWER

Prepared for the

Utility Air Regulatory Group

Prepared by

J. Edward Cichanowicz
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April 29, 2014

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SUMMARY

The Environmental Protection Agency (EPA) on January 8, 2014 published New Source Performance Standards (NSPS) for emissions of Greenhouse Gases (GHG) from new electric generating units (EGUs). This GHG NSPS rule references a 2013 Regulatory Impact Analysis[1] (2013 RIA) to support numerous provisions. Perhaps the most important of these is EPA's prediction that – for the period from 2020 to 2040 - supercritical coal-fired plants (SCPC) cannot compete with natural gas-fired combined cycle (NGCC) combustion turbines in economically generating power. Specifically, EPA projects a SCPC coal-fired EGU will produce power at a levelized cost of $81/MWh, over the period from 2020 to 2040, on a 2011-dollar basis. In contrast, EPA estimates NGCC will produce electricity over the same time period for $59/MWh. Consequently, EPA assigns SCPC power a cost "premium" of $22/MWh over NGCC power. As a result, EPA projects negligible new coal-fired capacity will be built and thus no costs are incurred by the GHG rule.

This paper critiques EPA's conclusion and the assumptions in the cost methodology. Specifically, EPA's analysis uses inputs that are highly uncertain over the several decade period that is the subject of this analysis. Two of the most important inputs to EPA's analysis are the "overnight" cost of capital for SCPC and NGCC process equipment, and fuel cost. Estimates of capital cost for both SCPC and NGCC – based on six engineering studies funded by the Department of Energy in the last six years –

[1] *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for Stationary Sources: Electric Utility Generating Units*, EPA-452/R-13-003, Sept. 2013.

are highly volatile, varying with the year in which any given report is issued. The projections of fuel price, prepared by the Energy Information Agency (EIA), although perhaps the best estimates available, have historically not been accurate over multi-decade periods. Further, other key inputs for financing, and fixed and variable operating and maintenance costs are equally uncertain. These inputs are demonstrated to significantly affect the results.

EPA's cost calculation was replicated given information in the RIA. A series of sensitivity analyses were conducted that examined the effect of modest changes in overnight capital cost, finance charges, fixed and variable operating and maintenance charges, and fuel prices. The results show the cost premium for SCPC-generated electricity over NGCC is eliminated with only modest changes to the input assumptions for the cost calculation.

INTRODUCTION

EPA on January 8, 2014 published NSPS for emissions of GHGs for new electric generating units. This GHG NSPS rule references a 2013 RIA[2] to support numerous provisions. Perhaps the most important of these is EPA's prediction that – for the period from 2020 to 2040 – supercritical coal-fired plants cannot compete with natural gas-fired combustion turbines in economically generating power. As a result EPA projects negligible new coal-fired capacity will be built.[3] EPA relies on this prediction to argue that as no coal-fired power plants will be built there are no costs incurred by the GHG rule.

It should be noted EPA changed the calculation methodology the Agency used in the 2013 RIA compared to the 2012 RIA[4], the latter released in support of EPA's 2012 GHG NSPS proposal. In brief, EPA abandoned the metric of <u>cost of electricity</u> in favor of the <u>levelized cost of electricity</u>. EPA did not explicitly justify this change, except to state the latter represents the cost "of building and operating a generating facility over the entirety of its economic life"; and further to enable comparisons "between generating types with similar operating characteristics but with different cost and financial characteristics."[5]

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[2] Ibid.

[3] See Section 5.2 of the 2013 RIA. Table 5-1 shows no (i.e. zero) coal-fired sources are selected for new generation.

[4] Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, EPA-452/R-12-001, March 2012. Hereafter 2012 RIA.

[5] 2013 RIA, page 5-17.

EPA: COAL-FIRED GENERATION CANNOT COMPETE

EPA cites two analyses in the 2013 RIA to support its conclusion that SCPC generation cannot compete with NGCC.

First, a cost analysis conducted by ICF argues that, for a range of capital investment and fuel prices, NGCC is the sole competitive generating option. EPA used ICF's proprietary Integrated Planning Model (IPM) to simulate the demand for new generating units based on estimates of wholesale power and fuel prices. Specifically, EPA modeled a Reference Case in addition to several scenarios that reflect alternate fuel price projections from the Energy Information Agency (EIA).[6] Details of the IPM are not available for review due to the proprietary nature of the model.

Perhaps due to IPM's proprietary status, EPA used a second "static, engineering cost analysis" to justify its conclusion.[7] EPA states this latter analysis is intended to identify market conditions that could erode "the private cost advantages of NGCC over coal during the analysis period."[8]

Figure 1 (replicated from Figure 5-3 of the 2013 RIA) presents the results of the EPA "static, engineering cost analysis" for the Reference Case conditions. Figure 1 reports the levelized cost of electricity generated, using NGCC ($59/MWh) and supercritical coal (SCPC w/o CUA, at $81/MWh), the latter without EPA's *climate uncertainty adder (e.g. CUA)*. The *climate uncertainty adder* is EPA's means to account for uncertainty regarding the prospects for CO_2 control. As will be discussed subsequently, adopting an arbitrary cost penalty for CO_2 control to use in a study to determine the cost of CO_2 control induces bias.

Figure 1 illustrates EPA's result that coal-based generation using supercritical pulverized coal without the *climate uncertainty adder* (SCPC w/o CUA) generates power for a cost that is $22/MWh greater than natural gas-based generation (NGCC).

This conclusion is challenged. It will be shown about one-third of the premium that EPA assigns to the levelized cost of electricity from SCPC compared to NGCC is eliminated if a modest uncertainty in capital is accounted for. Most of the remaining difference is eliminated with modest changes to other inputs as described in this report. These conclusions are valid if EPA's 3% *climate uncertainty adder* is ignored.

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[6] Table 5-3 of the RIA cites results from various fuel demand and price scenarios, per EIA.
[7] See bottom of page 5-16 of the 2013 RIA.
[8] Ibid.

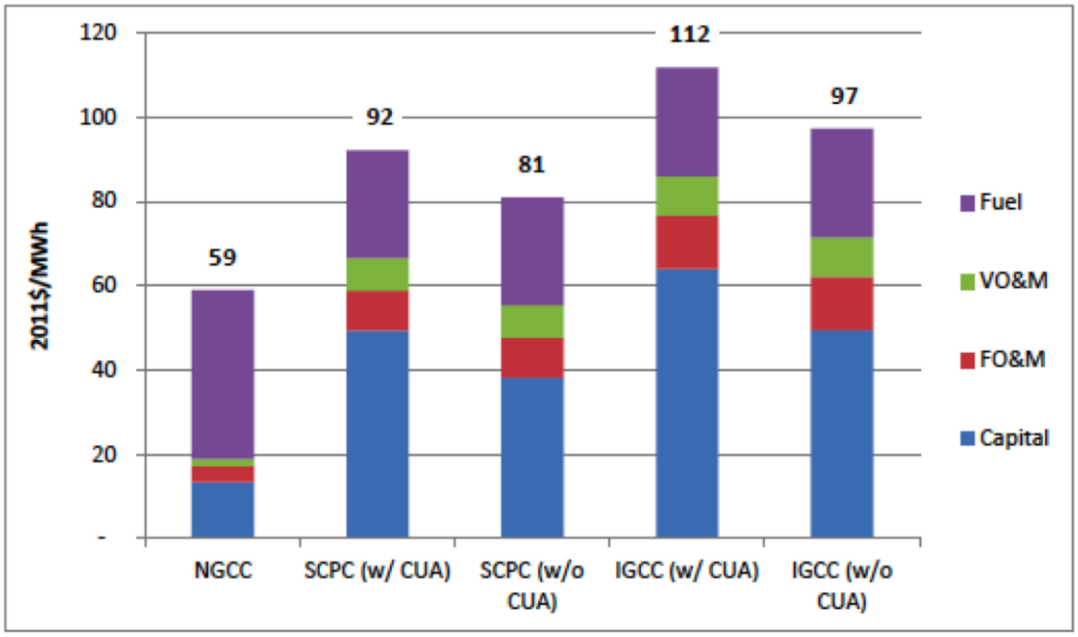

Figure 1. EPA Projected Levelized Cost of Electricity: Coal vs. Natural Gas, Reference Case (Figure 5-3 of the 2013 RIA)

OVERVIEW OF KEY INPUTS

EPA's 2013 RIA estimates future electricity production cost based on the average of predicted fuel prices, inflation rate, and the capital cost for SCPC and NGCC. EPA's approach – using mean values for key inputs such as equipment costs and fuel prices that only change with time in a tranquil and well-behaved manner – may be valid for projecting power costs averaged over a large geographic region. This approach does not simulate the variability of site and business conditions confronted by decision-makers on a regional or individual project basis. The most recent example of shortcomings of this approach was the projected "great moderation" of the financial environment that failed to detect the 2008 financial crisis.[9] In hindsight, some economists claim the predicted continuation of the "great moderation" did not adequately consider variability in asset prices.[10] Similarly, the EPA is ignoring authentic variability in capital and fuel costs and thus is erroneously eliminating coal-based generation as an option for the next three decades.

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[9] *The Origins of the Financial Crisis: Crash Course*, The Economist, September 7, 2013.
[10] *How Did Economists Get It So Wrong?* The New York Times Magazine, September 2, 2009.

Five features of EPA's approach merit discussion. These are the (a) climate uncertainty adder, (b) role of financing, (c) variability in capital cost estimates, (d) fixed and variable operating costs, and (e) fuel charges.

Climate Uncertainty Adder

EPA recognizes that proposed coal-fired plants incur several forms of resistance that increase the cost of permitting and construction. Emissions of CO_2 can be a focal point of resistance. Escalation in project costs can be driven by delays due to litigation and the need to study numerous alternatives. EPA proposes to quantify the cost impact of these delays by adding a 3% surcharge to the capital cost of a coal-fired power plant. Arbitrarily assigning a cost penalty for CO_2 – in an analysis whose objective is to determine the cost to control CO_2 – necessarily biases outcome. The political climate encountered in permitting new coal-fired power plants is indeed hostile and higher costs are incurred – but these are non-technical concerns. EPA notes that several utilities have adopted such a charge for their internal resource plan. This simply means they accept the political reality – and the financial consequences - of permitting a new coal-fired power plant. Further, SCPC is not the only power generation technology to incur CO_2-based permitting challenges – NGCC units have recently incurred similar resistance.[11] The cost impact of the present permitting environment is real but should be handled as a separate accounting charge, similar to Allowance for Funds Used During Construction. This charge is not technology-based and should not bias the outcome of a cost study.

Capital Recovery Factor

The capital recovery factor defines the annual payment for capital. This factor – an annual charge that for recent financial conditions typically of 9 to 12% of total capital outlay - is analogous to a "mortgage payment" for capital equipment. This annual payment is fixed for the plant lifetime.

In the 2013 RIA, EPA cites capital recovery factors for NGCC and SCPC of 9.78 and 10.23%, respectively.[12] As will be discussed, using these capital recovery factors with the capital cost presented in the 2013 RIA does not reproduce the annual payment

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[11] EPA Issues Greenhouse Gas Permit for La Paloma Energy Center Project. Power engineering, April 7, 2014, available at http://www.power-eng.com/articles/2014/04epa-issues-greenhouse-gas-permit-for-la-paloma-energy-center-project.html

[12] See 2013 RIA, footnote 34 on page 5-17.

cited by EPA.[13] EPA may be employing other variables or using a capital recovery factor not described in its documentation. The 2013 RIA results can be approximated using capital recovery factors recommended in the most recent Department of Energy/National Energy Technology Laboratory cost evaluation of SCPC and NGCC.[14] These values of capital recovery - 11.6% and 12.4% for NGCC and SCPC, respectively – when used in the levelized cost of electricity calculation closely replicate the results in 2013 EIA Figure 5-3.

Variability in Capital Cost

The Department of Energy (DOE) has issued six studies since 2007 estimating the capital cost of generating equipment, almost invariably including SCPC and NGCC. These studies typically address SCPC both with and without carbon capture and sequestration (CCS) equipment, along with integrated gasification/combined cycle – also with and without CCS. Five studies address SCPC and NGCC; the sixth only addresses SCPC. These studies – listed in chronological order of release by DOE - are as follows:

1. Costs and Performance Baseline for Fossil Energy Plants, DOE/NETL-2007/1281, Volume 1: Bit Coal and Natural Gas to Electricity Report (original May 2007), Rev 1, Aug. 2007. This report is the original work to project state-of-art advanced pulverized coal and integrated gasification/combined cycle cost. Capital cost is reported on a 2007-year dollar basis.
2. Updated Capital Cost Estimates for Electricity Generation Plants, issued by the DOE U.S. Energy Information Administration in November of 2010, served as the basis for the 2012 RIA. Results are reported on a 2010 dollar-year basis, prepared by the engineering firm R.W. Beck.[15]
3. Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases, DOE/NETL-341/082312, Aug 2012, DOE NETL-341/082312. This report updates select "baseline" cases from the 2007 report.

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[13] Specifically, the levelized annual payment for capital cost (in terms of $/MWh) does not match that illustrated in Figure 5-3 of the RIA for the case of SCPC w/o the CUA. Using a capital cost of $2,452/kW, gross generating capacity of 580.3 MW, capacity factor of 85%, and a capital recovery factor of 10.23%, the levelized annual capital payment is determined to be $33.7/MWh (2011 basis). Figure 5-3 suggests an annual capital cost of about $38/MWh.

[14] *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture,* Revision 1 – September 19, 2013 (Original – May 27, 2011). Report DOE/NETL-2011/1498. Exhibit 2-23.

[15] *EOP III Task 1606, Subtask 3 – Review of Power Plant Cost and Performance Assumptions for NEMS*, Technology Documentation Report, prepared by R.W. Beck, Inc. for Science Applications International Corporation, October 2010. Available as Appendix A to DOE/EIA 2010.

4. Cost and Performance Data for Power Generation Technologies, sponsored by the DOE National Renewable Energy Laboratory, and issued in November 2012. Black & Veatch projected capital cost for (subcritical) pulverized coal and NGCC (2009 basis).
5. Costs and Performance Baseline for Fossil Energy Plants, DOE/NETL-2007/1397, Volume 1: Bit Coal and Natural Gas to Electricity Report (original May 2007), Rev 1, Aug. 2007. Revision 2 (November 2010) and Revision 2a (September 2013) are contained in this document.
6. Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, Revision 1 – September 19, 2013 (Original – May 27, 2011). Report DOE/NETL-2011/1498. This analysis, issued by the DOE National Energy Technology Laboratory (NETL) in September 19, 2013, updates cost estimates from 2011, reported on a 2007 dollar-year basis.

The fifth study serves as the basis for the 2013 RIA.

Notably, the capital costs of SCPC and NGCC projected by these six studies – all sponsored by the Department of Energy and conducted within about a six-year period – vary significantly. Figure 2 displays the capital cost estimated for both SCPC and NGCC from each study. All costs are escalated to a 2011-year dollar basis.

The earliest work – published in 2007 and based on market forces for generating equipment in the 2003 to 2006 timeframe – projects the least capital cost for both SCPC and NGCC. These estimates reflect market forces preceding the cost pressures that were incurred in the middle part of this century's first decade due to strong global demand for process equipment.

Subsequent studies issued from 2010 through 2012 reflect the strong global demand for process equipment. For example, the RW Beck study for the EIA – issued in November of 2010 - reported the highest capital cost for both SCPC and NGCC equipment. But a DOE/NETL report published less than 2 years later (DOE/NETL 341/082312) - released August of 2012 – projects lower SCPC costs by $1,000/kW. The estimate for NGCC equipment over this same time period differs by $200/kW.

That capital cost studies sponsored by the DOE – all conducted by reputable contractors – could vary by such a magnitude in only a few years time implies significant uncertainty in the estimating methodology.

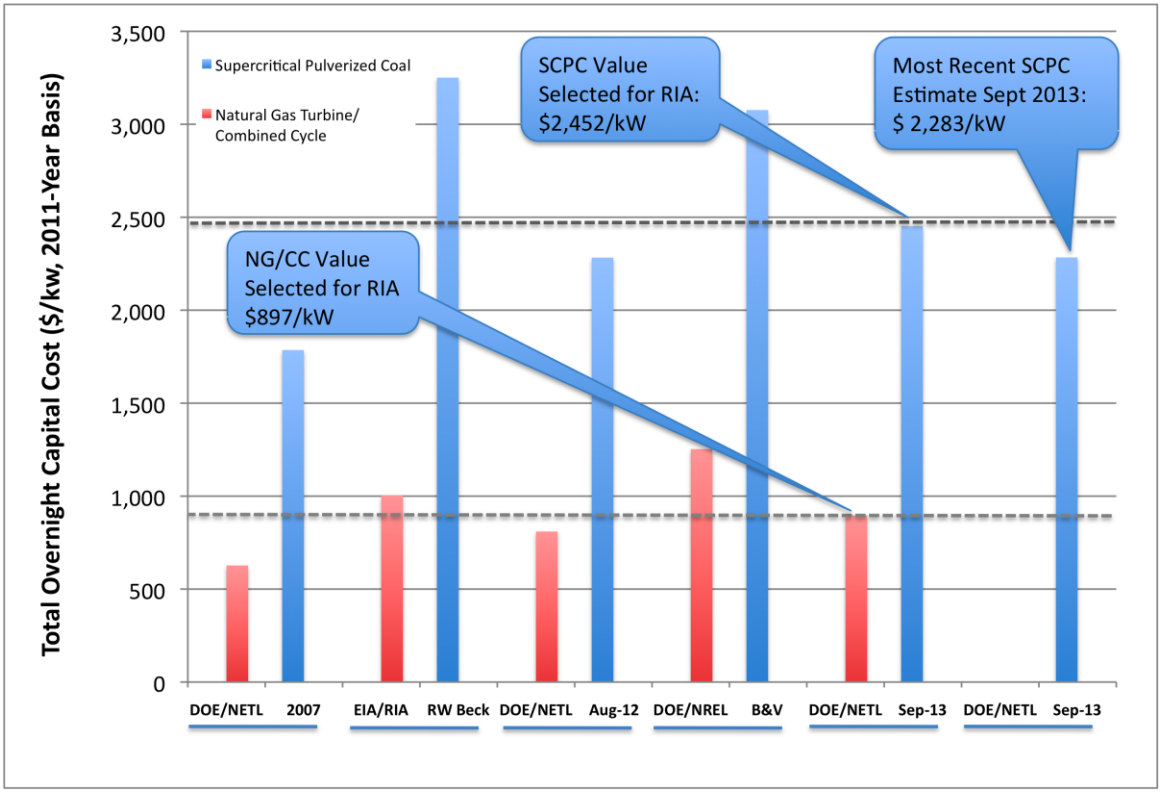

Figure 2. Comparison of Estimated Capital Cost for Supercritical Pulverized Coal (SCPC) and Natural Gas/Combined Cycle (NG/CC) Generating Equipment: Six DOE-Sponsored Studies (All cost in 2011-dollar basis).

None of the six studies was conducted to support the design, contracting, or construction of an actual plant – thus these estimates are classified as "budgetary." A significant degree of uncertainty - typically reported as +30% and –15% - characterize budgetary estimates. EPA selected the fifth NETL study (DOE/NETL-2007/1397, Revision 2a in September 2013) to support the RIA. Of interest is a sixth study (also released September 2013) that shows capital costs continue to relax, with a SCPC capital requirement of $2,283/kW – approaching pre-2007 levels.

In summary, Figure 2 demonstrates the volatility of capital cost estimates for SCPC and NGCC. Two NETL reports were released in September 2013 – both available from which to base an analysis – and EPA used the study with higher SCPC capital cost (by about $200/kW).

Fixed, Variable Operating Costs

Five of the six studies defined (on page 5) report fixed and variable operating and maintenance (O&M) charges for SCPC and NGCC equipment.

Table 1 compares these results. All costs reported in Table 1 are expressed on a 2011-year dollar basis. The sum of fixed and variable operating expenses is not always a large component of generating cost – perhaps not more than 10%, when combined.

Table 1 shows a factor of 2-3 variance in estimates for both fixed and variable O&M between five DOE-sponsored studies of SCPC and IGCC.

Table 1. Comparison of Fixed Operating Costs ($/kW-yr) and Variable Operating Cost ($/MWh) from Four Reference Studies

Page 6/7 Listing	DOE Report Designation	SCPC		NG/CC	
		Fixed O&M, $/kW-y	Var. O&M, $/MWh	Fixed O&M, $/kW-y	Var. O&M, $/MWh
1	DOE/NETL-2007/1281, Rev 1 Aug. 2007.	28.5	5.52	11.1	1.5
2	DOE/EIA, Nov. 2010.	36.9	4.36	14.68	3.50
3.	DOE NETL-341/082312 (June 2011).	66.9	5.68	24.9	1.49
4	NREL/Black & Veatch, Nov. 2012.	24.5	3.95	6.69	3.89
5	DOE/NETL-2007/1397, Rev 2a Sept. 2013.	70.6	7.74	26.7	1.76

For NETL reports the scope of activities addressed in the fixed and variable O&M costs are similar. Table 1 demonstrates that estimates of fixed and variable operating cost – similar to capital cost as depicted in Figure 2 - depend on the source document.

The 2013 RIA used values from the fifth report (DOE/NETL-2007/1397) which predicts the highest fixed O&M for both SCPC ($70.6/kW-y) and NGCC ($26.7/kW-yr). The variable (non-fuel) O&M costs selected for the 2013 RIA were the highest for supercritical coal ($7.74/MWh) but near the lowest for natural gas/combined cycle ($1.76/MWh).

Fuel Cost

EPA selected fuel prices for the 2013 RIA based on EIA estimates for a variety of supply/demand scenarios over the next 30 years.[16] Both natural gas and coal are addressed. This discussion will describe the uncertainties in fuel price projections and offer alternate fuel price inputs that are equally viable.

Natural Gas. Figure 3 presents natural gas price projections from the 2013 Annual Energy Outlook (AEO) that are used in the 2013 RIA (Figure 5-5 of the 2013 RIA). Specifically, Figure 3 presents delivered natural gas price in terms of a 2011-dollar year basis from 2015 through about 2040.

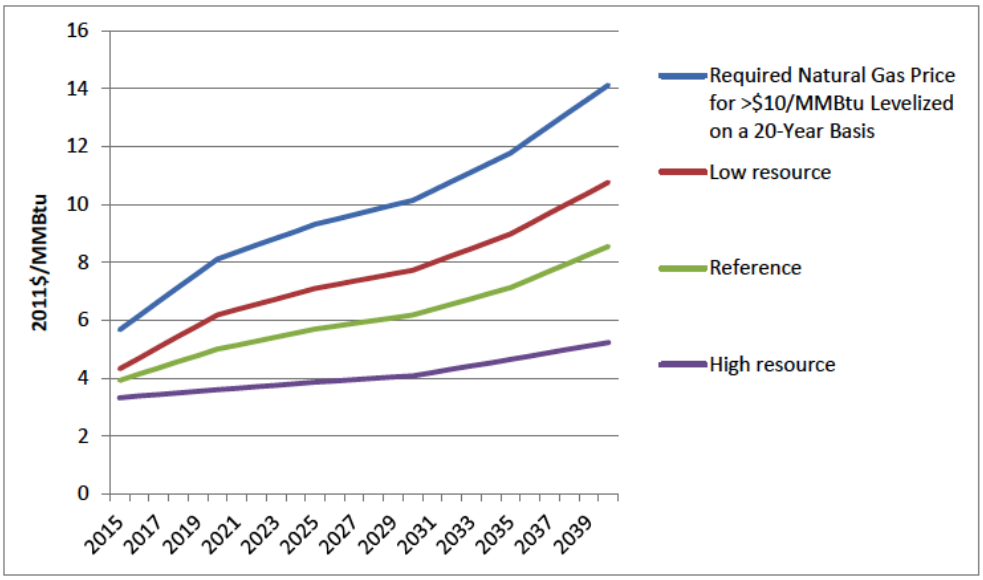

Figure 3. Projected Real Delivered Natural Gas Prices for Select 2013 Annual Energy Outlook Scenarios (Source: Figure 5-5 from the 2013 RIA).

EPA uses Figure 3 to select a representative fuel charge to calculate the levelized cost of electricity. EPA picks a price intermediate to the first 20-year term of the plant, designating this to be a levelized charge of $6.11. EPA's choice of $6.11/MBtu sounds high in the context of early 2014 market prices - but this reflects a levelized value over the period of 2020 to 2040.[17]

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[16] *AEO Early Release Overview*, available at http://www.eia.gov/forecasts/aeo/er/index.cfm

[17] EPA changed the fuel price used in calculating the levelized cost of electricity between 2012 RIA and 2013 RIA, having using $5/MBtu in 2012. The purpose for the change in cost basis is not clear.

EIA's predicted natural gas prices to 2040 may be the best estimate available. This paper does not question EIA's ability to predict natural gas prices over the next several decades, but EPA's decision to assume a generation portfolio nearly devoid of new advanced SCPC based on this assumption.

Coal. The minemouth price of coal differs widely across the U.S., due to differences in mining productivity, labor costs, equipment costs, and transportation rates.

Figure 4 displays EIA's projected minemouth coal prices, from present to 2040, for three coal-producing regions in the U.S. (2011 dollar basis). Figure 4 depicts up to a factor of 3 variation in coal price between the West, Interior, and Appalachia regions.

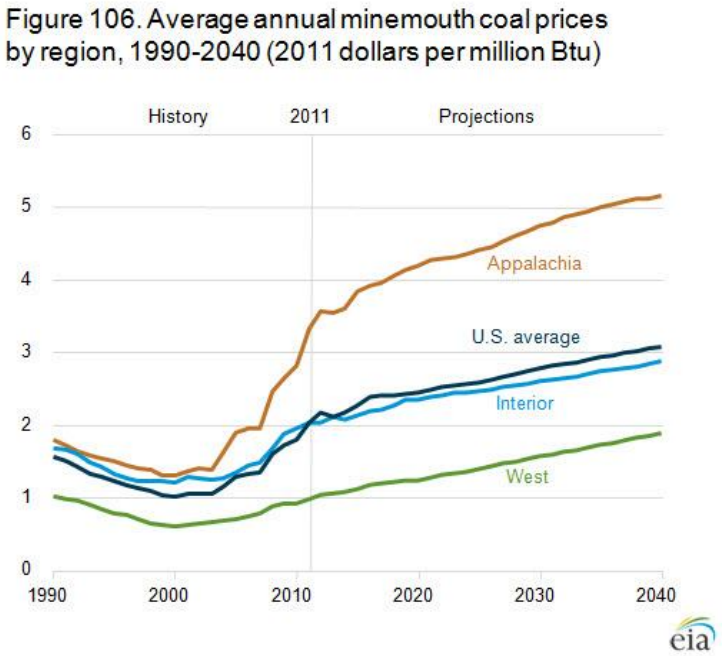

Figure 4. Average Annual Minemouth Coal Prices by Region, 1990-2040, 2011 dollars per MBtu. (Source: Figure 106 from the 2013 Energy Information Agency Annual Energy Outlook.

The "West" region is where many new coal-fired power plants have been proposed or are under construction. For example, more than half of the 15 "transitional" new greenfield units identified in the 2012 EPA RIA are located in the "west."[18] In fact, the 2013 Annual Energy Outlook – a key input to EPA's modeling assumptions – includes an alternative "Low Coal Cost" case with average minemouth coal cost of

[18] EPA RIA, Appendix 2A

$1.70/MBtu in 2014.[19] Replicating EPA's step of selecting a 2030 fuel price to represent a levelized fuel cost from 2020 to 2040, a minemouth coal price in Figure 4 of $1.50/MBtu will be used. This minemouth price translates into a delivered price of about $2.25-2.50/MBtu for plants in western states near coal mines.

SCPC, NGCC CAN BE EQUIVALENT

This section presents results of sensitivity studies comparing the levelized cost of electricity from both SCPC and NGCC for the Reference Case, addressing alternate values of capital cost, finance charges, fixed and variable operating cost, and fuel price. Figure 5 presents results for both SCPC and NGCC generating equipment.

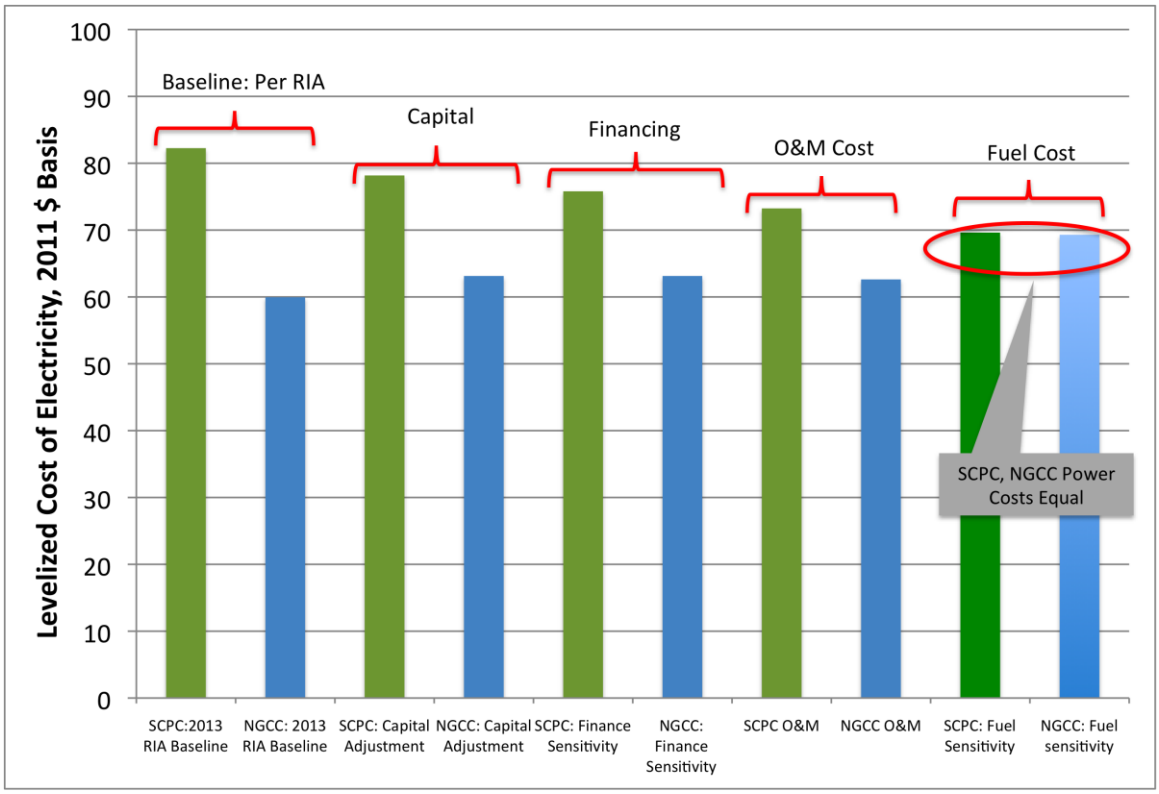

Figure 5. Levelized Cost of Electricity: SCPC vs. NGCC, Per Sensitivity Analysis

Figure 5 presents the 2013 RIA reference case on the far left. The other cases presented in Figure 5 show the sensitivity to (a) capital input, (b) financing charge, (c)

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[19] 2013 Annual Energy Outlook – Markets Trends, Coal. Available at http://www.eia.gov/forecasts/aeo/MT_coal.cfm

fixed and variable operating cost, and (d) fuel charge. Examining results from left to right, the following scenarios are described:

2013 Baseline: SCPC, NGCC. The levelized cost of electricity for the Reference Case for both SCPC and NGCC is presented. As previously noted, the values of $81/MWh for SCPC and $59/MWh could not be exactly reproduced using the inputs described in the 2013 RIA. However, these values could be approximated (to within $1/MWh) using the capital recovery values in the same 2013 NETL analysis (DOE/NETL-2007/1397) that provided the capital costs. These capital recovery values are 12.4% and 11.6%, respectively, for SCPC and NGCC.[20]

EPA's reported "premium" for the levelized cost of electricity from SCPC over NGCC, based on the Reference Case, is $22/MWh.

Capital Cost Sensitivity. Given the uncertainty in capital cost estimates for SCPC and NGCC – cited by EPA as up to +30% and -15% – a sensitivity analysis is warranted. EPA's projected demand for SCPC and NGCC – a near collapse for SCPC but robust for NGCC – suggests a contemporaneous cost decrease for SCPC and cost increase for NGCC should be explored.

A second report issued by DOE in September 2013 (DOE/NETL-2011/1498) projects SCPC capital cost below the value assumed in the 2013 RIA by almost 10% (i.e. to $2,284/kW). This sensitivity analysis adopts a 10% decrease to SCPC capital cost (to $2,207/kW) and a 15% increase to NGCC capital cost (to $1,025/kW). This assumed difference in capital cost is within the range reflected in the six DOE-sponsored studies, as exhibited in Figure 2.

The decrease in SCPC capital cost lowers the levelized cost of electricity from SCPC to $78/MWh while the increase in capital cost elevates that from NGCC to $63/MWh. As a result, EPA's "premium" for SCPC based on these revised capital costs is reduced to $15/MWh.

Eliminate Finance Bias. Both SCPC and NGCC are mature technologies and will present the same technical risk. In actuality, the additional construction period for SCPC will slightly elevate costs for interest during construction, but that factor is not reflected in the "total overnight cost". Assuming equal finance charge enables both

[20] The levelized cost of electricity is exactly replicated when a capital recovery charge of 12.0% and 10.8% is used for SCPC and NGCC, respectively. The calculations in this report used the DOE/NETL values of 12.4% and 11.6% and employed the approximate results in the so-called Reference Case.

options to be considered on technical merits and not affected by the vagaries of the commercial bond market.

Finance charges for both SCPC and NGCC are assumed to be the "low risk" charge used in the 2012 NETL study (11.6%). Using this value, the levelized cost of electricity for SCPC is lowered to $76/MWh while NGCC is unchanged at $63/MWh. As a result, EPA's "premium" for SCPC decreases to $13/MWh.

Operating and Maintenance Cost. Table 1 demonstrates how both fixed and variable operating and maintenance costs vary between the DOE-sponsored studies that have addressed this topic. Similar to the sensitivity analysis conducted for capital cost, a change in fixed and variable O&M costs will be assumed that is relatively small and consistent with recent DOE-funded studies. Specifically, the fixed and variable O&M assumptions adopted in the 2011/2012 NETL report[21] – representing a 5-7% reduction in fixed O&M and a 15-27% reduction in variable O&M for both SCPC and NGCC – will be adopted.

The change in fixed and variable O&M lowers the levelized cost of electricity for SCPC to $73/MWh while that for NGCC decreases slightly to $62.6/MWh (essentially $63/MWh). EPA's "premium" for SCPC based on these revised O&M costs is about $10/MWh.

Escalate the Levelized Price Of Natural Gas. The levelized cost of natural gas was increased by $1/MBtu - from EPA's reference value of $6.11/MBtu to $7.11/MBtu. This is not a large variation for a predicted fuel price over two decades. Using this fuel charge increases the levelized cost of electricity from NGCC increases to $69/MWh.

Decrease Coal Prices: Western Fuels, Modest Transportation Costs. The delivered coal price is reduced from $2.94/MBtu to $2.50/MBtu – assuming a cost at the mine of $1.50-1.75/MBtu and allowing for $0.75-1.00 delivery for a plant with limited transportation distance.

The levelized cost of electricity from SCPC decreases to $69.6/MWh or effectively $70/MWh– essentially equal to that of NGCC at $69/MWh.

In summary, Figure 5 shows successive changes to four key cost inputs – capital, financing, operating and maintenance, and fuel price - remove any premium in the

[21] Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases, DOE/NETL-341/082312, Aug 2012, DOE NETL-341/082312.

levelized cost of electricity for coal-fired SCPC versus NGCC. Each generates power for about $69-70/MWh.

COMMENTS ON EPA SENSITIVITY

The 2013 RIA did not conduct a parametric sensitivity as presented in this paper. Rather, the 2013 RIA addressed individual (and not cumulative) changes in capital cost and fuel price that moved in the same direction.

For example, EPA allowed the capital cost of SCPC and NGCC to vary only due to changes in construction labor between various regions in the U.S. The sensitivity analysis conducted by EPA addressed the case where costs for both SCPC and NGCC increase or decrease, in the same direction, due only to changes in the AEO "Regional Capital Cost Scalar."[22] The variability in capital cost estimates implied by the six DOE studies was ignored, as the role of market forces that could decrease SCPC capital cost and increase NGCC capital cost.

Regarding fuel, EPA considered changes that reflect average price movement within each region, as determined by EIA's Electricity Market Module (EMM) region. EPA's use of the average of all regions does not portray the dynamics within any one region. Most notably, EPA did not consider regions near western coal mines where PRB delivered prices are typically relatively low compared to the national average for coal prices, and where natural gas would require at least a modest distribution charge.

In summary, the inputs assumed for Figure 5 represent one set of realistic conditions under which NGCC and SCPC are equivalent in terms of levelized cost of electricity.

[22] See Table 5-7, page 5-26.

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Fuel Prices, Emission Standards, and Generation Costs for Coal vs Natural Gas Power Plants

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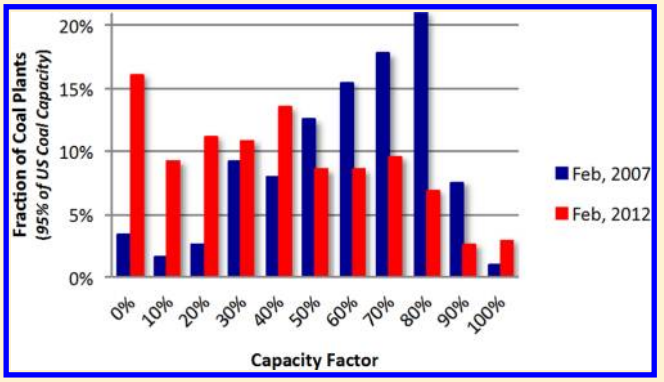
Supporting Information

ABSTRACT: Low natural gas prices and stricter, federal emission regulations are promoting a shift away from coal power plants and toward natural gas plants as the lowest-cost means of generating electricity in the United States. By estimating the cost of electricity generation (COE) for 304 coal and 358 natural gas plants, we show that the economic viability of 9% of current coal capacity is challenged by low natural gas prices, while another 56% would be challenged by the stricter emission regulations. Under the current regulations, coal plants would again become the dominant least-cost generation option should the ratio of average natural gas to coal prices (NG2CP) rise to 1.8 (it was 1.42 in February 2012). If the more stringent emission standards are enforced, however, natural gas plants would remain cost competitive with a majority of coal plants for NG2CPs up to 4.3.



INTRODUCTION

Monthly CO_2 emissions from the U.S. electricity sector have fallen to 1990 levels helping to reduce total U.S. CO_2 emissions to their lowest levels since 1992.[1,2] This decline is largely due to greater use of lower CO_2-emitting natural gas power plants in place of coal plants, a shift made possible by low natural gas prices stemming from the surge in domestic shale gas production.[3] In fact, the low prices appear to be at least part of the reason that announced coal-plant closures have reached 8.5% of the current coal fleet capacity,[4] a figure that economic modeling suggests could double if gas prices remain depressed.[5,6]

However shutting coal plants down may also be the least-cost option some operators will pursue if the Environmental Protection Agency (EPA) implements stricter air-emission, coal-combustion, and cooling-water regulations.[4−9] The tighter air-quality standards alone will require upgrades to emission control systems (ECTs) at many natural gas as well as coal plants. But whereas the affected natural gas plants typically produce only NO_x emissions in excess of the lower thresholds, the affected coal plants may also be exceeding reduced SO_2, particulate matter (PM), and mercury (Hg) limits making it more expensive for these plants to come into compliance. This has engendered both legal and political debate over whether pending and tightening existing EPA regulations unfairly disadvantage the U.S. coal industry.[10]

At the same time, uncertainty persists over how long natural gas prices will remain low. With shale gas and now gas associated with shale oil becoming as cheap to produce as conventional gas, U.S. natural gas reserves have rebounded 88% over the past ∼20 years, and production currently exceeds the previous peak set in 1973.[11] Production costs and thus natural gas prices may well rise though due to pending EPA regulations on emissions from the "fracking" process used in shale gas (or oil) production and any future regulations on water use in fracking.[12,13] Prices might also increase in response to the rising demand for natural gas from the U.S. manufacturing sector and even from other countries if the U.S. significantly increases its exports of liquid natural gas.[14,15]

Even if natural gas prices rise, however, the U.S. electricity sector could still continue its shift away from coal plants and toward greater use of lower CO_2-emitting natural gas plants. This is because the economics of natural gas vs coal plants depends not only on the price of natural gas, but also on the price of coal and on the expense of meeting the stricter EPA regulations. We illustrate this interplay by showing how fuel prices and more stringent emission standards can affect the cost of generating electricity (COE) for 95% of the coal plant capacity and 70% of the natural gas plant capacity currently operating in the U.S. We first explore how the COE for these plants under the present EPA emission standards has been altered by the change in fuel prices between February 2007 and February 2012. We then show how much current plant COEs would increase if all the plants were to comply with the stricter EPA standards the EPA will be imposing for SO_2, NO_x, PM, and Hg as specified in the Mercury and Air Toxic Standards (MATS), the Clean Air Interstate Rule (CAIR and CAIR+),

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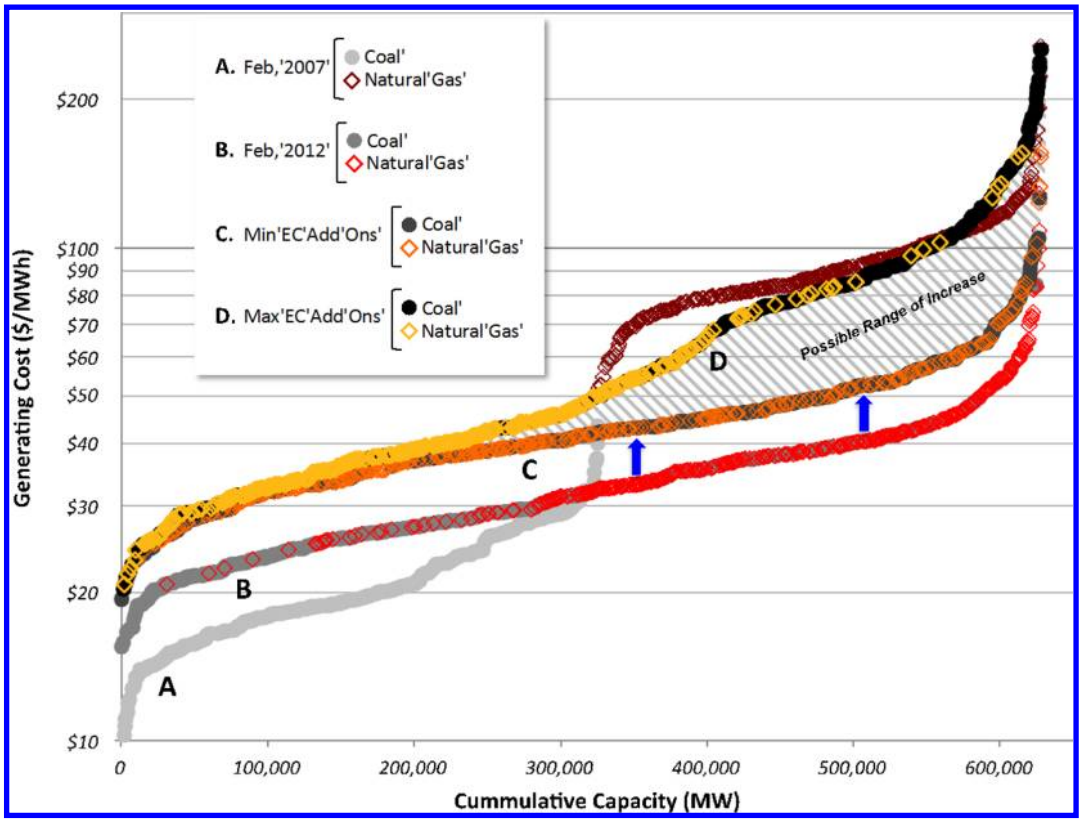

Figure 1. COE curves for 304 coal plants (totaling 325 651 MW or 95% of current U.S. coal capacity) and 358 natural gas plants (totaling 302 557 MW or 70% of current U.S. natural gas capacity). Each plant is used solely for power generation and has a rated capacity >65 MW.[19,20] COE curves based on EC_{curr} for (A) 2/2007 and (B) 2/2012, and COE curve for 2/2012 after (C) low and (D) high EC_{rev} estimates for meeting EPA MATs,[28] CAIR,[29] and ARP[30] standards. COEs are based on the average spot prices for coal and natural gas delivery to electric utilities in 2/2007 (A) and 2/2012 (B–D) in the states where each plant is located.[18] See the Supporting Information for further details on COE and EC estimations.

and other updates to the Clean Air Act Amendment (CAAA). Finally, we generalize our analysis to show how the COEs of natural gas and coal plants may change under a range of possible future fuel prices by expressing these in terms of a natural-gas-to-coal-price ratio (NG2CP both prices in $/MMBtu). When COEs are viewed in this context, it becomes clear that the current economic competitiveness of natural gas plants with respect to coal plants is highly sensitive to the NG2CP, but that this sensitivity will be significantly muted if and when pending and stricter existing EPA regulations are enforced.

METHODS

We estimate the COE for coal and natural gas power plants that have a rated capacity >50 MW, are used solely for power generation, and for which data are available on fuel consumption and electricity generation from January 2007, through February 2012 (Table S1). The combined capacity of the 304 coal plants that meet these criteria is 325 651 MW (95% of the current U.S. coal-fired fleet capacity), while that of the 358 natural gas plants that we analyze is a similar 302 557 MW (70% of the current natural gas-fired fleet capacity).

Each plant's COE ($/MWh) is estimated as

$$\mathrm{COE} = (\mathrm{FP} \times \mathrm{HR}) + \begin{vmatrix} \mathrm{EC}_{\mathrm{curr}} \\ \mathrm{EC}_{\mathrm{rev}} \end{vmatrix} \quad (1)$$

where FP is the fuel price ($/MMBTU) and HR is the plant's net heat rate (MMBTU/MWh). EC_{curr} is the total operation and maintenance (O&M) cost ($/MWh) for all emission control technologies (ECTs) currently on the plant excluding the electricity cost of their parasitic load. EC_{rev} is EC_{curr} plus any additional O&M *and* capital costs for ECT installations/upgrades the plant would need to meet the tighter emission standards (e.g., Figure 1C,D). Capital and O&M costs for the rest of the plant are excluded from eq 1 because: the capital and fixed O&M costs are sunk costs and should not affect decisions to dispatch, retrofit, or replace the plant; data on fixed and variable O&M costs for individual plants are lacking; and coal and natural gas plants have comparable O&M costs. For example, both types of plants have similar fixed O&M costs (for maintenance materials and labor, administrative support, and operating labor,[16] and their variable O&M costs (e.g., water consumption and waste disposal) are 2 orders of magnitude smaller than their fuel costs.[17]

The data used for FP are the monthly averaged U.S. state spot prices for coal and natural gas delivered to power plants as published in the EIA Electric Power Monthly Technical Reports from February 2007 and February 2012.[18]

HR comes from the 2012 EPA eGrid database.[19] While eGrid gives a nominal HR for each plant, some of these are unrealistically low (efficient) or high (inefficient), so we use the median of the plant's monthly net HR between January 2007 and February 2012 as a more robust measure of the plant's true efficiency. We compute the latter HRs from the plant's monthly fuel consumption (MMBTU) and electricity generation (MWh) as reported in eGrid.[19]

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Current plant ECTs are assumed to be those reported in the 2012 EPA eGrid Database,[19] and the 2007 (released in 2011) NETL Coal Power Plant Database.[20] For those plants that installed new ECTs in 2011 or were scheduled to do so in 2012, we updated this information according to the EPA *2011 Coal Characteristics and Controls* database from the last quarter of 2011.[21] Finally we cross-referenced each plant with the ECTs listed in the 2011−2012 EPA *Air Market Emissions Database* to ensure updated information.[22]

Information on the plant ECTs is used to estimate the fixed and variable O&M costs that make up each plant's EC_{curr}. With the EPA-Integrated Planning Model (IPM)[23−25] and the Carnegie-Mellon University Integrated Environmental Control Module (IECM)[26] for existing ECTs not addressed in IPM (i.e., spray- and tray-type scrubbers, jet bubbling reactors, and advanced overfire air), we generate generalized cost O&M functions for each type of ECT using a base coal or natural gas power plant of 100, 300, 500, 700, 1000, and 2500 MW capacity. The empirical cost functions are then used to approximate the total O&M costs for the specific ECTs on a plant given its design (coal or natural gas) and capacity.

EC_{rev} is again EC_{curr} plus the O&M *and* capital costs for any ECT upgrades or additions a plant will need to meet the more rigorous EPA regulations. Plants that will require ECT upgrades/installations to remain operational are identified by comparing their current SO_2, NO_x, PM, and Hg emissions to the stricter EPA standards coming online. We assume that current plants with emissions that exceed the standards implied by cap-and-trade programs will comply by retrofitting rather than buying allowances. Current plant emissions at the boiler and plant level are from 2011 EPA Air Market Emissions Database[22] and the EPA TRI Database.[27] The stricter EPA standards vary by criteria pollutant and the regulations that would govern them.

SO_2 is addressed under MATS as an alternative form of compliance for reducing acid-rain forming HCl emissions. The MATS standards (summarized in Table S2) apply to all coal- and oil-fired units ≥25 MW in capacity starting in 2016.[28] Under MATS, the new SO_2 limit for existing plants will be 1.5 lb/MWh (0.20 lb/MMBTU), while for new coal units it will be 0.40 lb/MWh. Otherwise stricter standards of down to 0.30 lb/MWh will take precedence as governed by CAIR, ARP, New Source Performance Standards (NSPS), or individual U.S. state implementation plans (SIPs).[28−33] The one-hour National Ambient Air Quality Standard (NAAQS) of 75 ppb SO_2 will also remain in force.[28]

NO_x emissions, which are regulated under the CAAA, will be capped under CAIR to reach target average emissions rates of 0.15 lb/MMBtu in 2010 and 0.125 lb/MMBtu in 2015 (Table S3).[29] Note that these rates are not the standards themselves, but benchmarks that will be used to calculate an overall emissions limit for CAIR, which also includes a cap-and-trade program involving 28 eastern U.S. states and the District of Columbia (DC). The cap-and-trade component to CAIR complicates determination of a plant's new ECT requirements, so we assume that the previously mentioned 2015 benchmark rate are the emissions standard electric generators will face.

Twelve of the states affected by CAIR along with DC will also have to meet CAIR+, an additional rule developed by the Northeast Ozone Transport Commission that sets NO_x limits at 0.12 lb/MMBtu for 2009 and 0.08 lb/MMBtu for 2012. States outside of CAIR/CAIR+ on the other hand are required to meet either (1) the NAAQS NO_x limit of 0.15 lb/MMBtu and 100 ppb per 1 h, (2) the CAAA emissions limit of 0.40−0.86 lb/MMBtu (based on generator design), or (3) the NSPS standards.[29−31] Similar to CAIR, the NAAQS limit is also a benchmark rate that we use to estimate an overall emissions standard, and as with CAIR, we assume all plants will have to meet the benchmark emissions rate. We note, however, that both CAIR and NAAQS standards are under review, and these may end up being even more stringent. If so, the nonattainment areas for NO_x will grow, and more ECT additions will be required.

Mercury was regulated under the CAAA (Section 112 under the Mercury (CAM) Rule) for about three years as (2005−2008) but will now be regulated under MATS.[28] The new mercury emission standards are 0.021−0.145 lb/GWh depending on fuel type.[28]

Finally, PM is regulated by the NAAQS 24 h and annual standards, which along with MATS replaces the CAIR PM standards.[29] In many cases, the NAAQS may be more stringent on PM than MATS, which treats the pollutant as a surrogate for mercury and other heavy metals. The fine PM standards are 35 $\mu g/m^3/d$, and 15 $\mu g/m^3/y$, while the coarse PM standard, which is only a daily standard, is 150 $\mu g/m^3/d$.[33]

When comparing the current plant emissions data with the lowered EPA limits,[22,27−30] we assume that ECT installations/upgrades will be made if a boiler in a plant does not meet the stricter standards for one or more of the aforementioned pollutants. If on the other hand the boiler does not have an ECT installed for the pollutant(s) but is meeting the stricter emission standard(s), no ECT(s) is (are) added. Furthermore, if a specific state or region has more rigorous standards based on an existing SIP,[31] these lower limits are used. We also do not consider any cobenefits of the ECTs.

Once we have identified the subset of plants that will need one or more ECT upgrades/installations to meet the stricter EPA standards, we assign these plants an EC_{rev} that along with EC_{curr} includes the additional O&M and capital costs for the ECT upgrade. We obtain the additional O&M costs in EC_{rev} by using the same cost functions described for determining EC_{curr}; that is, the additional capital costs in EC_{rev} are estimated using empirical functions fit to the capital costs output by the IPM and IECM for a given ECT installed on a base power plant of 100, 300, 500, 700, 1000, and 2500 MW capacity (see SI Table S4; modeling assumptions are detailed in the table caption).[26,34]

All ECT upgrade costs are determined from the cost functions at the boiler level and then scaled to the plant level using a capacity-weighted sum of the boiler costs. Any additional costs associated with retrofitting the plant with the particular ECT are included in the cost functions as these are based on retrofit data published in the IPM and IECM documentation.[23−26]

Finally, we recognize that there are different types of ECTs for each pollutant (e.g., SO_2, NO_x, and PM) and that more than one of these technologies might be suitable for meeting the stricter EPA standards but at different costs. Therefore rather than basing the upgrade costs on a particular type of ECT for each pollutant, we estimate both a low and high levelized cost of plant compliance based on the cheapest and costliest ECTs, respectively, that would achieve the required pollutant reductions. The choice of appropriate capacity factors for making these estimates is not an easy one. Historical capacity factors have little predictive value when the relative COE of coal and natural gas plants is expected to change. We assume

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that either type of plant if retrofitted will be dispatched much more often and, in the absence of any better information, use capacity factors that are the 95th percentile in cumulative histograms of historic capacity factors for each plant type, that is, 88% for coal plants and 77% for natural gas plants.[19,20] Such capacity factors are rather high and may lead us to underestimate the capital costs of ECTs, but if so our general conclusions are unlikely to be affected because the bias will be consistent across plant types.

RESULTS AND DISCUSSION

Figure 1 illustrates how the fall in natural gas prices as well as a less heralded rise in coal prices has changed the COE for the majority of U.S. coal and natural gas plants operating under EC_{curr}. In February 2007, the average price of natural gas delivered to electric utilities was $8/MMBTU, while that for coal was $1.7/MMBTU.[35] This resulted in a clear separation between the COEs for the two types of plants, with >99% of the coal plants being cheaper to operate than all of the natural gas plants. By February 2012, however, the average price utilities were paying for natural gas had dropped ~60% to $3.4/MMBTU, while that for coal had climbed >35% to $2.4/MMBTU.[36] Under these circumstances, many natural gas plants became as inexpensive to operate as coal plants, blurring the two sets of COEs while significantly lowering the marginal cost for electricity.

The change in fuel prices also led to a significant shift in how coal and natural gas plants were operated. Figure 2 shows that >60% of coal plants had capacity factors of 60% or higher in February 2007, but that by February 2012 only 30% of these plants had such high capacity factors. The capacity factors for natural gas plants on the other hand rose over this period, with the fraction of these having capacity factors ≥60% more than tripling from 6% in February 2007 to 20% in February 2012. Nonetheless, while fewer coal *plants* were being run for baseload in the February 2012 (Figure 2), >75% of the coal *capacity* remained cheaper to operate than the average natural gas plant (Figure 1).

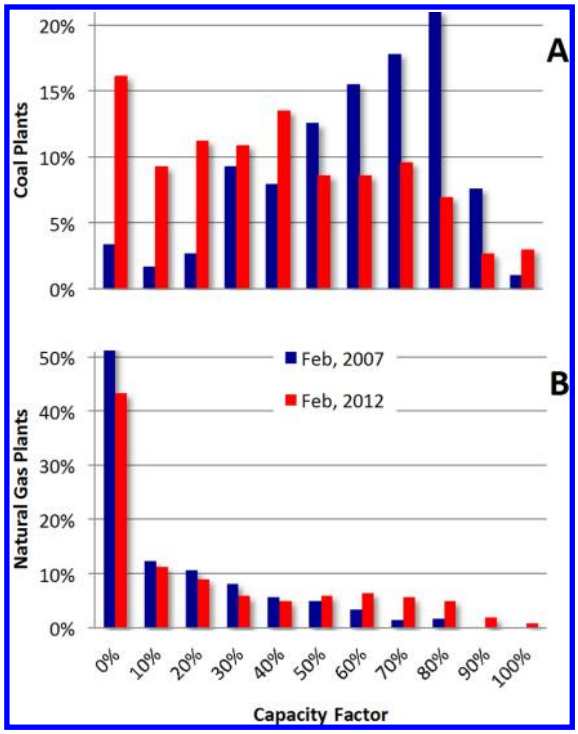

Figure 2. Change in capacity factor from February 2007 (blue) to February 2012 (red) for (A) coal-fired power plants and (B) natural gas power plants. Note that the shift in coal capacity factors is more significant than that for natural gas capacity factors. This appears to be due to the added effects of a decline in electricity demand and an increase in wind capacity over the same time period.[5]

The potential additional impact of more stringent emission regulations on the COEs of both coal *and* natural gas plants is represented by the two other curves in Figure 1, which factor in low and high estimates for EC_{rev} (see Supporting Information). Our lowest and most conservative EC_{rev} estimate would shift the COE curve ~$10/MWh above that for 2/2012 (Figure 1). The change in COE for individual plants, however, varies considerably about this amount (Figure 3). Natural gas plants would become even cheaper relative to coal plants because the former typically need only upgrade the NO_x system if it does not already meet the lower emission standards. For many coal plants on the other hand, emission controls for SO_2, PM, and mercury need to be upgraded/installed. As a result, the average low EC_{rev} estimate for the natural gas plants is $1.7/MWh, while for the coal plants it is $23.5/MWh. There is also considerable variation in the COE increase among the coal plants themselves. Some 6% of the plants already meet the stricter EPA standards, while the remainder would need a partial to full emission control upgrade, raising their COEs between <1% to >200% (Figure 3).

In fact, these before-and-after COEs for coal plants can be divided into three groupings (Figure 3). One consists of plants with COEs higher than the median COE for natural gas capacity irrespective of whether the more stringent EPA standards lead to the minimum EC increase (Figure 3A). The continued viability of these plants, which make up 9% of current U.S. coal capacity, is threatened by low natural gas prices. In the second group are coal plants with COEs that change from being cheaper to costlier than the median natural gas plant COE after the minimum EC increase (Figure 3B). The continued viability of this group, which totals 56% of current U.S. coal capacity, is threatened by the stricter standards. The third group consists of coal plants that remain cost competitive with natural gas capacity even after the minimum EC increase (Figure 3C). Note that this group contains at least two plants slated to be shutdown. These planned retirements are at least partly in response to stakeholder opposition to continued operation of the plants,[9,11] illustrating that a host of reasons drive coal plant closures. The majority of closing plants included in our sample, however, are in the group that would experience the greatest COE increases if EPA regulations are implemented (Figure 3B).[37] This suggests that most planned shutdowns are more a response to the stricter regulations than to low natural gas prices.

The sensitivity of coal and natural gas plant COEs to fuel price changes under current emission standards is illustrated in Figure 4A. Here the cumulative capacity of coal and natural gas plants is plotted along the *y*-axis in order of increasing plant COE (Figure S1). Colors represent the fraction of coal vs natural gas generating capacity at each 1% increment in cumulative capacity (Figure S1). These fractions change with changes in the natural gas to coal price ratio (NG2CP) (Figure S1). In general, natural gas plants remain uniformly more expensive to operate than all but the most expensive coal plants until the NG2CP falls below 2.2. In February 2012, the NG2CP

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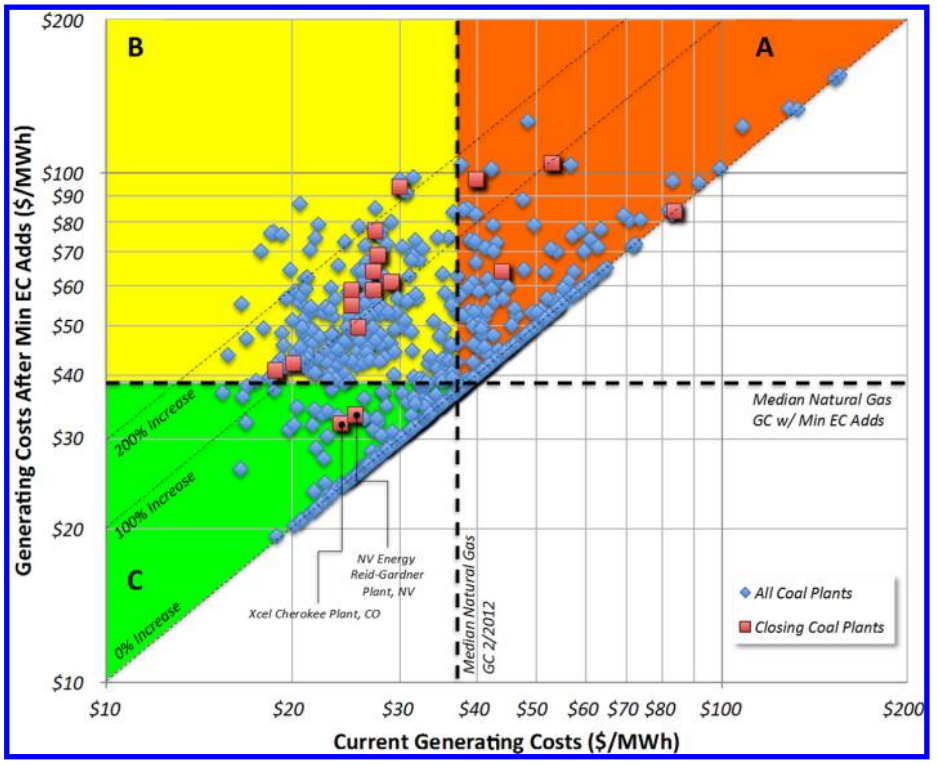

Figure 3. Coal plant COEs in 2/2012 with EC_{curr} (x-axis) vs the COEs with the low EC_{rev} that meet stricter EPA standards (y-axis): blue diamonds are all plants, red squares are 17 plants slated to close that (i) have a >65 MW capacity, (ii) are power-only plants, and (iii) of which we have sufficient data to estimate their COE.[37] For plants along 0% increase line, COEs remain unchanged, while they double and triple for plants along 100% and 200% increase lines, respectively. The plot is divided into three regions: (A) coal plants (av. cap. ~800 MW) with higher COEs than the median for natural gas plants at current gas prices, (B) coal plants (av. cap. ~900 MW) with COEs that become higher than median for natural gas plants after the low EC increase, and (C) coal plants (av. cap. ~1500 MW) with COEs that remain lower than the median after the low EC increase.

reached 1.42, a level at which the cheapest natural gas plants approach the COE of the cheapest coal plants. Historical data suggests this low level is a relatively rare occurrence, however (Figure 4C).[18] In fact, the NG2CP is predicted to rise back up toward 2 by 2020 (Figure 4A).[5] In the absence of EPA rules, this would result in >85% of the current coal fleet capacity once again having a lower COE than the cheapest natural gas plant (Figure 4A).

If EPA regulations are enforced, however, the relative competitiveness of natural gas plants becomes much less sensitive to the NG2CP (Figure 4B). In this case, the NG2CP can reach 4.3 before a majority of coal capacity has a COE less than that of the cheapest natural gas capacity (Figure 4B). The NG2CP has averaged >3.5 since January 2002, but continued high production rates of shale gas are predicted to keep the NG2CP <2.8 until 2035 (Figure 4C).[5] Should this prediction hold true, then natural gas capacity would remain cost competitive with coal capacity for at least two decades.

Our assumption that plants that exceed the average for the more stringent SO_2 emission standard must upgrade their SO_2 ECT ignores the cost-compliance benefits of SO_2 cap-and-trade programs. Similarly we ignore the possibility that the capital costs of ECT investments might be partially offset by any decrease in a utility's current payments for tradable emission allowances.[38] We also fail to consider the pollution reduction and thus cost-saving synergies that might come from coupling different ECTs on a plant. These and other simplifications in our analysis may lead to overestimates for the capital and O&M costs of complying with the stricter EPA rules. At the same time, we have not accounted for other factors that will likely increase the cost of operating coal plants, such as the new rules governing coal-combustion-residuals and cooling water use.[4−8] While our COE estimates are undoubtedly inaccurate at the plant level, the broader trends they reveal provide a consistent framework for understanding the effect of natural gas prices and EPA regulations on coal and natural gas plant COEs now and into the future. Our analysis partially supports the findings of previous economic modeling studies that low natural gas prices could indeed be driving a significant fraction of coal plants to close.[5,6] However, we also show that the relative competitiveness of coal vs natural gas plants is highly sensitive to the NG2CP and that a moderate increase (if natural gas prices rise and/or coal prices decline) could alter COEs such that a majority of coal plants once again becomes significantly cheaper than the lowest cost natural gas plant. Despite projections of natural gas prices remaining ≤$6/MMBTU out to 2030,[5] NG2CP will inevitably increase from current levels. If EPA regulations are enforced, however, natural gas plants will remain cost competitive relative to coal even if additional demand for U.S. natural gas by domestic manufacturers or liquid natural gas exporters doubles the current NG2CP.

The possibility of generating electricity from natural gas at a competitive cost is certainly a strong factor in favor of retiring coal plants instead of retrofitting them, but it may not be the determinant factor. An extreme shift to natural gas for electricity generation requires the development of necessary infrastructure to transport and store the gas in a way that guarantees its reliable supply to power plants. Also, as investors in the industry make retrofit/retirement decisions in planning their future power generation portfolio, these investors may

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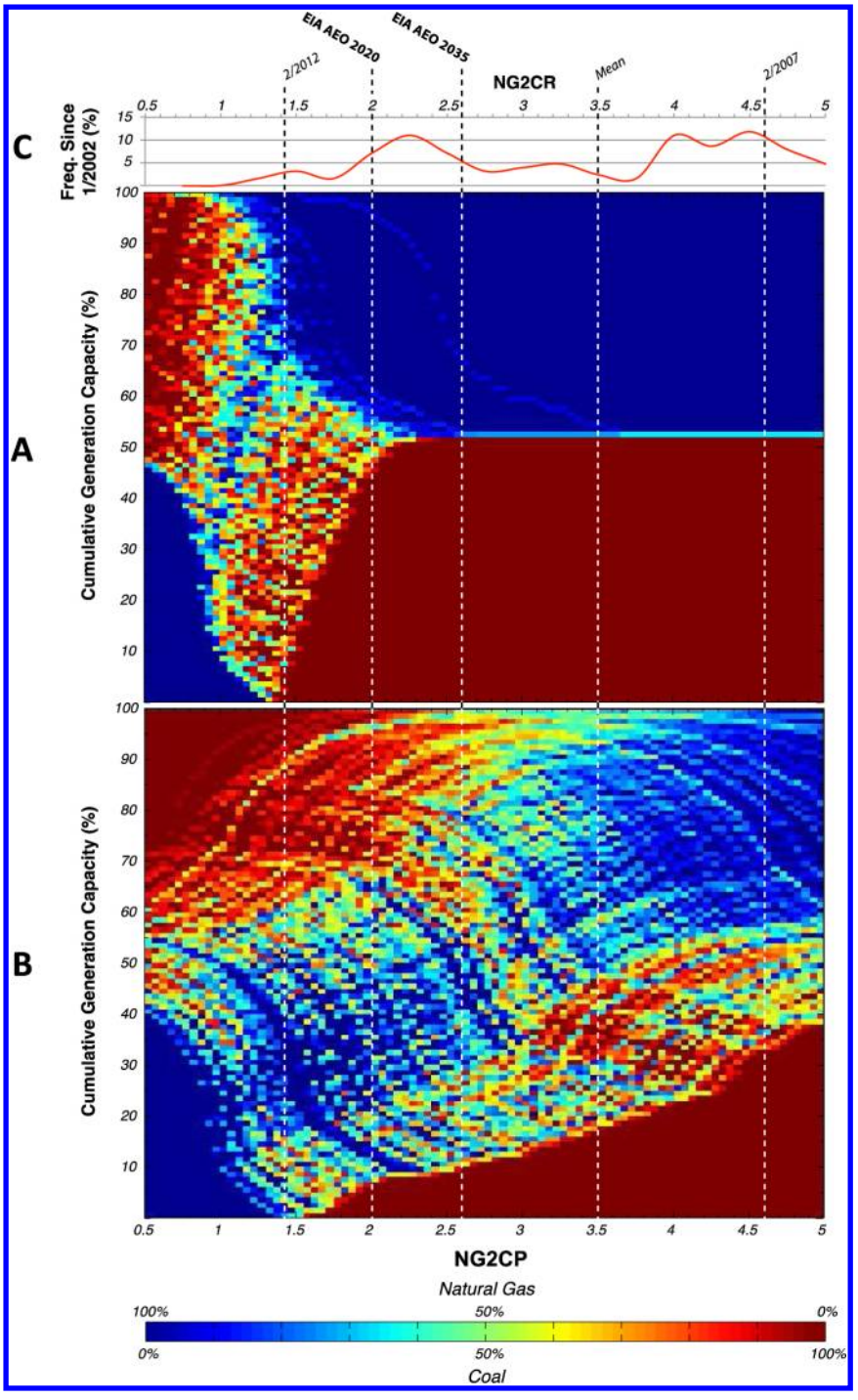

Figure 4. Coal and natural gas generation capacity ordered from low to high COE (i.e., supply curve) along lines of increasing cumulative capacity (*y*-axis) over a range of NG2CPs (*x*-axis): (A) COEs based on EC_{curr}, and (B) COEs based on low EC_{rev} estimates. Color scale indicates the fraction of coal vs natural gas capacity making up each 1% increment in cumulative capacity. (C) Frequency distribution of average monthly NG2CPs in the U.S. since January 2002.[17] Dashed lines demarcate past and predicted (EIA AEO)[5] average NG2CPs with *Mean* representing the average historical NG2CP. While COEs were estimated using constant coal and natural gas prices, the relative distributions of plant type along the lines of cumulative generating capacity compare favorably with those seen in Figure 1 (compare distributions along February 2007 and February 2012 in (A) to Figure 1A,B). A more direct and detailed comparison is shown in SI, Figure S1.

find it desirable to keep existing coal-fired power plants operational. Proposed federal regulations to constrain carbon dioxide emissions of new coal-fired power plants will limit their installation and inevitably make existing plants a valuable resource for maintaining a diversified power plant portfolio. But even if the transition from coal to natural gas becomes a near-term reality of the U.S. electricity industry the coal that is not consumed in the U.S. may find its way to other countries as it is already doing in Europe and Asia.[39] Consequently, the net effect on global CO_2 emissions of stringent air emission rules and low cost natural gas in the U.S. remains uncertain.

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■ ASSOCIATED CONTENT

Supporting Information

Table S1 (included as a separate Excel file) lists the coal and natural gas plants used in this study, including their unique Energy Information Administration (EIA) ID, plant name, state location, rated capacity, median monthly heat rate, state averaged spot price for fuel in February 2007 and February 2012, estimated O&M costs for current ECTs, and the low and high estimates of the cost of emission control installation/upgrades needed to meet the more stringent EPA standards. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

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Natural Gas Combined-Cycle Plants With and Without Carbon Capture & Sequestration

Technology Overview

Two Natural Gas Combined-Cycle (NGCC) power plant configurations were evaluated, and the results are presented in this summary sheet. Both cases were analyzed using a consistent set of assumptions and analytical tools. The two configurations evaluated are based on an NGCC plant with and without carbon capture and sequestration (CCS).

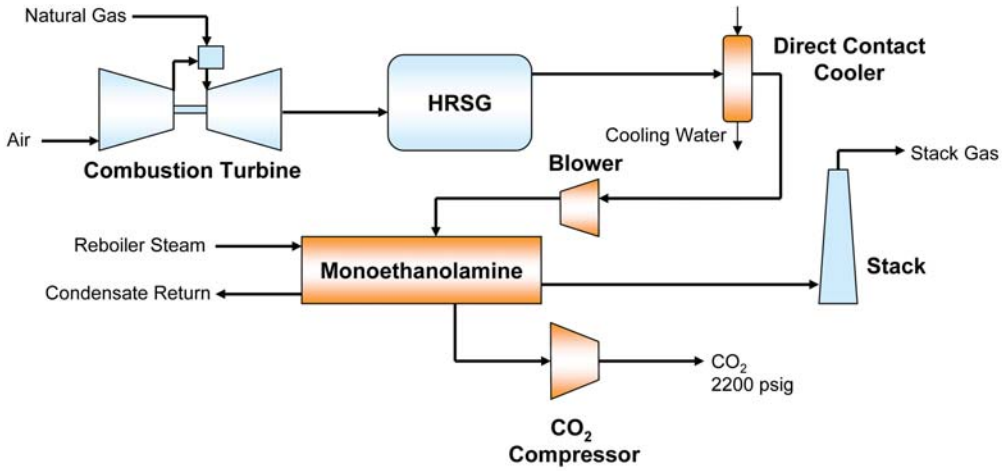
- NGCC plant utilizing Advanced F-Class combustion turbine generators (CTGs).
- NGCC plant utilizing Advanced F-Class CTGs with CCS.

Each NGCC plant design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 startup date. The NGCC plants are built at a greenfield site in the midwestern United States and are assumed to operate in baseload mode at 85 percent capacity factor (CF) without sparing of major train components. Nominal plant size (gross rating) is 570 MWe without CCS and 520 MWe with CCS. All designs consist of two advanced F-Class CTGs, two heat recovery steam generators (HRSGs), and one steam turbine generator in a multi-shaft 2x2x1 configuration.

The NGCC cases were evaluated with and without CCS on a common thermal input basis. The case that includes CCS is equipped with the Fluor Econamine (FG) Plus™ process. The NGCC with CCS case also has a smaller plant net output resulting from the additional CCS facility auxiliary loads and steam consumption. After compression to pipeline specification pressure, the carbon dioxide (CO_2) is assumed is to be transported to a nearby underground storage facility for sequestration.

The size of the NGCC designs was determined by the output of the commercially available combustion turbine. Therefore, evaluation of the NGCC designs on a common net output basis was not possible. For the cases with and without CCS, respective gross output was 520 and 570 MWe, and respective net output was 482 and 560 MWe. The natural gas (NG) flowrate was 165,182 lb/hr in both cases. See Figure 1 for a generic block flow diagram of an NGCC plant. The orange blocks in the figure represent the unit operations added to the configuration for CCS cases.

Figure 1. NGCC Plant



Nitrogen oxides control: dry low-NOx burner + selective catalytic reduction to maintain 2.5 ppmvd @ 15% oxygen

Carbon dioxide control: Monoethanolamine system for 90% removal

Steam conditions: 2,400 psig/1,050°F/950°F

Orange blocks indicate unit operations added for CCS case.

Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The combined-cycle plant was based on two CTGs. The CTG is representative of the advanced F-Class CTGs with an International Standards Organization base rating of 184,400 kWe (when firing NG). This machine is an axial flow, single-shaft, constant-speed unit, with variable inlet guide vanes and Multi-Nozzle Quiet Combustor dry low-NOx (DLN) burner combustion system. Additionally, a selective catalytic reduction (SCR) system further reduces the nitrogen oxides (NOx) emissions. The Rankine cycle portion of both designs uses a single-reheat 16.5 MPa/566°C/510°C (2,400 psig/1,050°F/950°F) cycle. Recirculating evaporative cooling systems are used for cycle heat rejection. The efficiency of the case without CCS is almost 51 percent, with a gross rating of 570 MWe.

The CCS case requires a significant amount of auxiliary power and extraction steam for the process, which reduces the output of the steam turbine. This results in a lower net plant output for the CCS cases of about 482 MWe for an average net plant efficiency of almost 44 percent higher heating value (HHV).

The CCS case is equipped with the Fluor Econamine Flue Gas (FG) Plus™ technology, which removes 90 percent of the CO_2 in the FG exiting the HRSG unit. Once captured, the CO_2 is dried and compressed to 15.3 MPa (2,215 psia). The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline formation, which is located within 50 miles of the plant. Therefore, CO_2 transport, storage, and monitoring costs are included in the analyses.

Table 1. Fuel Analysis

Natural Gas		
Component		**Volume Percentage**
Methane	CH_4	93.9
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon dioxide	CO_2	1.0
Nitrogen	N_2	0.8
Total		**100.0**
	LHV	**HHV**
kJ/kg	47,764	52,970
kJ/scm	35	39
Btu/lb	20,552	22,792
Btu/scf	939	1,040

Fuel Analysis and Costs

The design NG characteristics are presented in Table 1. Both NGCC cases were modeled with the design NG.

A NG cost of $6.40/MMkJ ($6.75/MMBtu) (January 2007 dollars) was determined from the Energy Information Administration AEO2007 for an eastern interior high-sulfur bituminous coal.

Environmental Design Basis

The environmental design for this study was based on evaluating both of the NGCC cases using the same regulatory design basis. The environmental specifications for a greenfield NGCC plant are based on the pipeline-quality NG specification in Table 1 and EPA 40 CFR Part 60, Subpart KKKK. Table 2 provides details of the environmental design basis for NGCC plants built at a midwestern U.S. location. The emissions controls assumed for each of the two NGCC cases are as follows:

Table 2. Environmental Targets

Pollutant	NGCC
SO_2	Negligible
NOx	2.5 ppmvd @ 15% Oxygen
PM (filterable)	Negligible
Hg	N/A

- Dry low-NOx burners in conjunction with SCR for NOx control in both cases.
- Econamine process for CO_2 capture in the CCS case.

NGCC plants produce negligible amounts of SO_2, particulate matter (PM), and mercury (Hg); therefore, no emissions controls equipment or features are required for these pollutants.

Major Economic and Financial Assumptions

For the NGCC cases, capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates were developed for each plant based on adjusted vendor-furnished and actual cost data from recent design/build projects and resulted in determination of a revenue-requirement 20-year LCOE based on the power plant costs and assumed financing structure. Listed in Table 3 are the major economic and financial assumptions for the two NGCC cases.

Project contingencies were added to each of the cases to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 10.6 percent for the NGCC case without CCS TPC and roughly 13.3 percent for the NGCC case with CCS.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- CO_2 Removal System – 20 percent on all NGCC CCS cases.
- Instrumentation and Controls – 5 percent on the NGCC CCS cases.

Table 3. Major Economic and Financial Assumptions for NGCC Cases

Major Economic Assumptions	
Capacity factor	85%
Costs year in constant U.S. dollars	2007 (January)
Natural gas delivered cost	$6.75/MMBtu
Construction duration	3 Years
Plant startup date	2010 (January)
Major Financial Assumptions	
Depreciation	20 years
Federal income tax	34%
State income tax	6%
Low risk cases	
After-tax weighted cost of capital	8.79%
Capital structure:	
Common equity	50% (Cost = 12%)
Debt	50% (Cost = 9%)
Capital charge factor	16.4%
High risk cases	
After-tax weighted cost of capital	9.67%
Capital structure:	
Common equity	55% (Cost = 12%)
Debt	45% (Cost = 11%)
Capital charge factor	17.5%

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for NGCC cases.

For the NGCC case that features CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage field, associated storage in a saline aquifer, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

Results

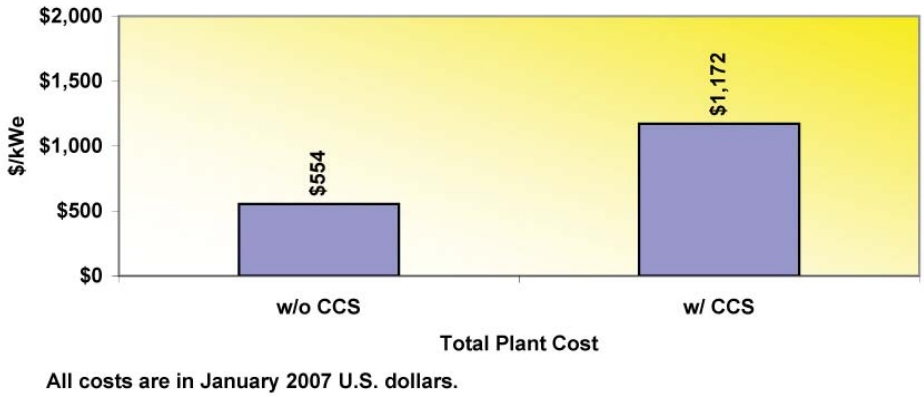
The results of the analysis of the two NGCC cases are presented in the following subsections.

Capital Cost

The total plant cost (TPC) for each of the two NGCC cases is compared in Figure 2. The TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

The results of the analysis indicate that an NGCC costs $554/kWe, and that an additional $618/kWe is needed for the NGCC plant with CCS.

Figure 2. Comparison of TPC for the Two NGCC Cases

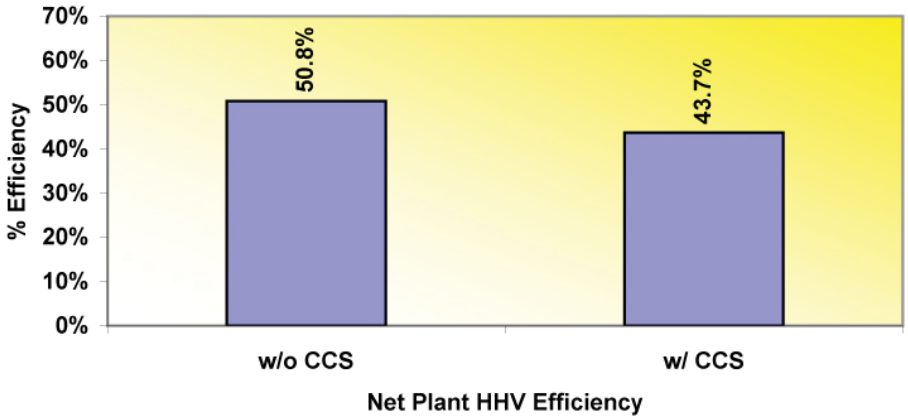


All costs are in January 2007 U.S. dollars.

Efficiency

The net plant HHV efficiencies for the two NGCC cases are compared in Figure 3. This analysis indicates that adding CCS to the NGCC reduces plant HHV efficiency by more than 7 percentage points, from 50.8 percent to 43.7 percent.

Figure 3. Comparison of Net Plant Efficiency for the Two NGCC Cases



Levelized Cost-of-Electricity

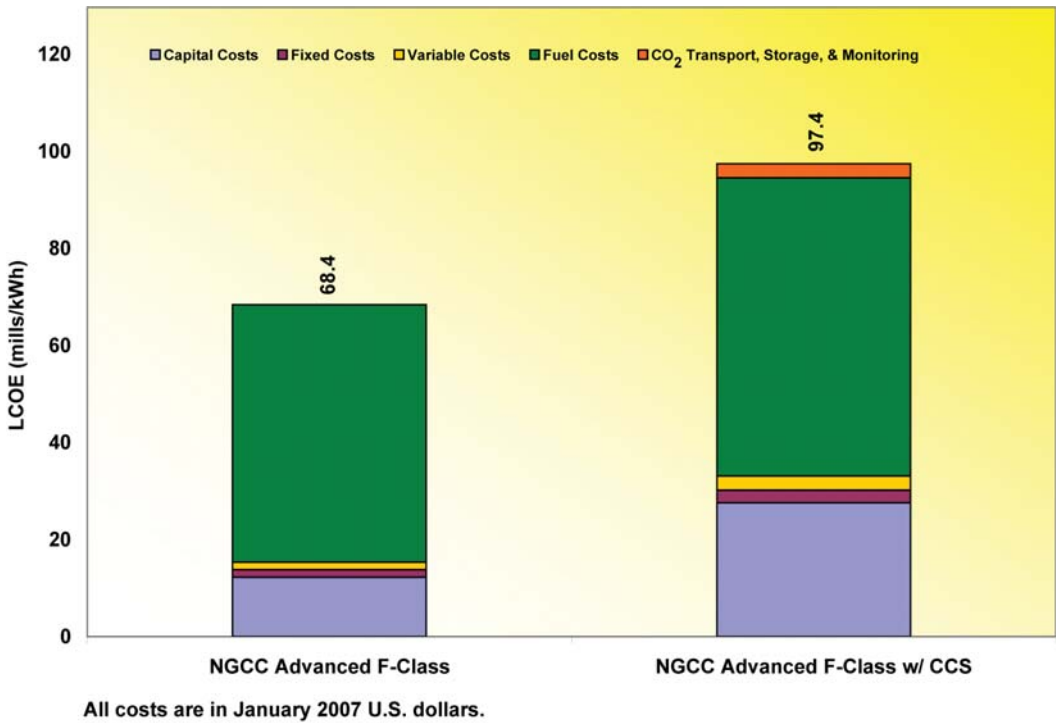
The LCOE is a measurement of the coal-to-busbar cost of power, and includes the TPC, fixed and variable operating costs, and fuel costs levelized over a 20-year period. The calculated cost of transport, storage, and monitoring for CO_2 is about $7.00/short ton, which adds roughly 3 mills to the LCOE.

The NGCC without CCS plant generates power at an LCOE of 68.4 mills/kWh at a CF of 85 percent. When CCS is included, the increased TPC and reduced efficiency result in a higher LCOE of 97.4 mills/kWh.

Environmental Impacts

Listed in Table 4 is a comparative summary of emissions from the two NGCC cases. Mass emission rates and cumulative annual totals are given for sulfur dioxide (SO_2), NOx, PM, Hg, and CO_2.

Figure 4. Comparison of Levelized Cost-of-Electricity for the Two NGCC Cases



The emissions from both NGCC plants evaluated meet or exceed Best Available Control Technologies requirements for the design NG specification and EPA 40 CFR Part 60, Subpart KKKK. The CO_2 is reduced by 90 percent in the capture case, resulting in less than 167,000 tons/year of CO_2 emissions. The cost of CO_2 avoided is defined as the difference in the 20-year LCOE between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh. In this analysis, the cost of CO_2 avoided is about $83/ton. Sulfur dioxide, Hg, and PM emissions are negligible. Raw water usage in the CCS case is over 85 percent greater than for the case without CCS primarily because of the large Econamine process cooling water demand.

Table 4. Comparative Emissions for the Two NGCC Cases @ 85% Capacity Factor

Plant Type	NGCC	
	Without CCS	With CCS (90%)
CO_2		
• tons/year	1,661,720	166,172
• lb/MMBtu	119	11.9
• cost of avoided CO_2 ($/ton)	N/A	83
SO_2		
• tons/year	N/A	N/A
• lb/10^6 Btu	N/A	N/A
NOx		
• tons/year	127	127
• lb/MMBtu	0.009	0.009
PM (filterable)		
• tons/year	N/A	N/A
• lb/MMBtu	N/A	N/A
Hg		
• tons/year	N/A	N/A
• lb/TBtu	N/A	N/A
Raw water usage, gpm	2,511	4,681

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
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