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U.S. EPA to propose utility carbon rules next year

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WASHINGTON, Nov 17 (Reuters) - The top U.S. environmental regulator will propose early next year twice-delayed rules on greenhouse gas emissions from power plants, she told the energyNOW television show.

"I can't tell you what the regulations say right now, but what we are planning to do is release them early next calendar year," Lisa Jackson, the Environmental Protection Agency administrator, told the program in a segment seen by Reuters that is to be broadcast over the weekend.

The EPA in June delayed the proposed rules on power plants, which are the largest source of U.S. greenhouse gas emissions, saying it needed more time after talking with businesses, states and green groups. It delayed them again in September.

Republicans in the House of Representatives have waged a war on EPA clean-air regulations, saying such rules will kill jobs and add costs to businesses suffering in a battered economy.

In September, President Barack Obama directed the EPA to delay a major rule on smog-forming pollutants until 2013, forcing Jackson to embrace a George W. Bush-era smog rule she previously described as legally indefensible.

The move led some environmentalists and health groups to worry the administration would subject other clean-air rules to long delays.

But earlier this month, the EPA sent the planned rules on carbon emissions from new power plants to the White House's Office of Management and Budget for review, a process that can take about 90 days.

The rules could force big coal-burning utilities, including Southern Co and American Electric Power , to use more natural gas, which is lower in carbon emissions, or to invest more in wind and solar power.

Jackson has said the agency's coming slate of clean-air rules can add jobs in technology to deal with smokestack emissions.

Lobbyists for utilities, however, say there is no affordable technology yet that can be bolted on to power plants to cut greenhouse gases.

A process to bury carbon dioxide emissions underground, known as carbon capture and sequestration or CCS, has been suggested as a way to help utilities cut emissions in coming years.

But Jackson, whose agency looked at CCS as it developed the rules, said the technology has a long way to go. "It can be years, maybe a decade or more, until we have the technology available at commercial scale," she said.

Cheaper options exist to cut emissions, she said.

"It would be shortsighted, or you would have to have blinders on, not to look at the fact that there are other game-changers out there like our nation's supply of natural gas that are going to be important as people look at where they want to make investment decisions," she said.

Lobbyists for the power industry say energy markets, not the EPA, should push utilities toward natural gas, adding that the chemical industry is also eyeing new natural gas supplies, which could eventually push up prices for the fuel.

PSD and Title V Permitting Guidance for Greenhouse Gases

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PSD and Title V Permitting Guidance for Greenhouse Gases

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Policy Division
Research Triangle Park, NC

Disclaimer

This document explains the requirements of EPA regulations, describes EPA policies, and recommends procedures for permitting authorities to use to ensure that permitting decisions are consistent with applicable regulations. This document is not a rule or regulation, and the guidance it contains may not apply to a particular situation based upon the individual facts and circumstances. This guidance does not change or substitute for any law, regulation, or any other legally binding requirement and is not legally enforceable. The use of non-mandatory language such as "guidance," "recommend," "may," "should," and "can," is intended to describe EPA policies and recommendations. Mandatory terminology such as "must" and "required" are intended to describe controlling requirements under the terms of the Clean Air Act and EPA regulations, but this document does not establish legally binding requirements in and of itself.

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I. Introduction

EPA is issuing this guidance document to assist permit writers and permit applicants in addressing the prevention of significant deterioration (PSD) and title V permitting requirements[1] for greenhouse gases (GHGs) that begin to apply on January 2, 2011. This document: (1) describes, in general terms and through examples, the requirements of the PSD and title V permit regulations; (2) reiterates and emphasizes relevant past EPA guidance on the PSD and title V review processes for other regulated air pollutants;[2] and (3) provides additional recommendations and suggested methods for meeting the permitting requirements for GHGs, which are illustrated in many cases by examples. We believe this guidance is necessary to respond to inquiries from permitting authorities and other stakeholders regarding how these permitting programs will apply to greenhouse gas (GHG) emissions.

This document is organized into sections with supporting appendices. Section I describes the purpose of this document, describes the actions that led to the permitting of sources of GHGs, and provides a general background for the permitting of major stationary sources. Section II describes PSD applicability criteria and how to determine if a proposed new or modified stationary source is required to obtain a PSD permit for GHGs. Section III discusses the process that EPA recommends following to determine best available control technology (BACT) for GHGs for new sources and modified emissions units. Section IV discusses how other PSD permitting requirements are generally inapplicable or have limited relevance to GHGs. Section V describes considerations for permitting of GHGs under title V of the Clean Air Act (CAA or Act). The appendices located at the end of this document include PSD applicability flowcharts for new and modified sources of GHGs, an example PSD applicability analysis for a modified source, example BACT analyses, compilations of resources for estimating emissions of GHGs and for finding control measures for sources of GHGs, and cost effectiveness calculation methodology.

EPA initially issued this GHG permitting guidance in November 2010. This version reflects a limited number of clarifying edits to the November 2010 guidance and replaces it.

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[1] Such requirements are reflected in provisions of the Clean Air Act, EPA rules, and approved State Implementation Plans. See 75 FR 17004 (Apr. 2, 2010).

[2] Collections of past EPA guidance on the PSD and title V review processes include:

- EPA websites listing some existing guidance documents for NSR (including PSD) (http://www.epa.gov/nsr/guidance.html) and title V (http://www.epa.gov/ttn/oarpg/t5pgm.html);
- Environmental Appeals Board (EAB) decisions on PSD permitting (http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/PSD+Permit+Appeals+(CAA)?OpenView) and title V permitting (http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Title+V+Permit+Appeals?OpenView); and
- EPA Region 7's online searchable database of many PSD and title V guidance documents issued by EPA headquarters offices and EPA Regions (http://www.epa.gov/region07/air/policy/search.htm).

Most of the EPA documents cited in this document can be found in one of these locations. To the extent this guidance relies on a document that is not located in one of the above collections, we have attempted to provide a website link or other relevant information to help locate the document.

all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.[41]

EPA has broken down this analytical process into the following five steps, which are each discussed in detail later in this section.

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies.

Step 4: Evaluate most effective controls and document results.

Step 5: Select the BACT.

To illustrate how the analysis proceeds through these steps, assume at Step 1 that the permit applicant and permitting authority identify four control strategies that may be applicable to the particular source under review. At the second step of the process, assume that one of these four options is demonstrated to be technically infeasible for the source and is eliminated from further consideration. The remaining three pollution control options should then be ranked from the most to the least effective at the third step of the process. In the fourth step, the permit applicant and permitting authority should begin by evaluating the energy, environmental, and economic impacts of the top-ranked option. If these considerations do not justify eliminating the top-ranked option, it should be selected as BACT at the fifth step. However, if the energy, environmental, or economic impacts of the top-ranked option demonstrate that this option is not achievable, then the evaluation remains in Step 4 of the process and continues with an examination of the energy, environmental, and economic impacts of the second-ranked option. This Step 4 assessment should continue until an achievable option is identified for each source. The highest-ranked option that cannot be eliminated is selected as BACT at Step 5, which includes the development of an emissions limitation that is achievable by the particular source using the selected control strategy. Thus, the inclusion and evaluation of an option as part of a top-down BACT analysis for a particular source does not necessarily mean that option will ultimately be required as BACT for that source.

Subcommittee (Feb. 3, 2010) at 16 and 18, *available at* http://www.epa.gov/oar/caaac/climate/2010_02_InterimPhaseIReport.pdf.

[41] 1990 Workshop Manual at B.2.

EPA developed the top-down process in order to improve the application of the BACT selection criteria and provide consistency.[42] For over 20 years, EPA has applied and recommended that permitting authorities apply the top-down approach to ensure compliance with the BACT criteria in the CAA and applicable regulations. EPA Regional Offices that implement the federal PSD program (through Federal Implementation Plans (FIPs)) and state permitting authorities that implement the federal program through a delegation of federal authority from an EPA Regional Office should apply the top-down BACT process in accordance with EPA policies and interpretations articulated in this document and others that are referenced. However, EPA has not established the top-down BACT process as a binding requirement through rule.[43] Thus, permitting authorities that implement an EPA-approved PSD permitting program contained in their State Implementation Plans (SIPs) may use another process for determining BACT in permits they issue, including BACT for GHGs, so long as that process (and each BACT determination made through that process) complies with the relevant statutory and regulatory requirements.[44] EPA does not require states to apply the top-down process in order to obtain EPA approval of a PSD program, but EPA regulations do require that each state program apply the applicable criteria in the definition of BACT.[45] Furthermore, EPA has certain oversight responsibilities with respect to the issuance of PSD permits under state permitting programs. In that capacity, EPA does not seek to substitute its judgment for state permitting authorities in BACT determinations, but EPA does seek to ensure that individual BACT determinations by states with approved programs are reasoned and faithful to the requirements of the CAA and the approved state program regulations.[46]

The discussion that follows in Section III provides an overview of the top-down BACT process, with discussion of how each step may apply to the aspects that are unique to GHGs. In addition, Appendices F, G, and H to this document provide illustrative examples of the application of the top-down BACT process to emissions of GHGs. These examples provide only basic illustrations of the concepts discussed in this document. A successful BACT analysis requires a more detailed record (that is, case- and fact-specific) to justify the conclusions reached by the permitting authority than can be provided in this guidance.

The most comprehensive discussion of the five-step top-down BACT process can be found in EPA's 1990 Draft New Source Review Workshop Manual ("1990 Workshop Manual"),[47] and the method has been progressively refined through federal permitting decisions by EPA, orders on title V permitting decisions, and opinions of the EPA Environmental Appeals Board (EAB) that have adopted many of the principles from the 1990 Workshop Manual and

[42] Memorandum from Craig Potter, EPA Assistant Administrator for Air and Radiation, to Regional Administrators, *Improving New Source Review Implementation* (Dec. 1, 1987); Memorandum from John Calcagni, EPA Air Quality Management Division, *Transmittal of Background Statement on "Top-Down" Best Available Control Technology (BACT)* (June 13, 1989).
[43] *Alaska Department of Environmental Conservation v. EPA*, 124 S.Ct. 983, 995 n. 7 (2004).
[44] *In re Cardinal FG Company*, 12 E.A.D. 153, 162 (EAB 2005) and cases cited therein.
[45] 40 CFR 51.166(b)(12); 40 CFR 51.166(j).
[46] *Alaska Department of Environmental Conservation v. EPA*, 124 S.Ct. 983 (2004); *In the Matter of Cash Creek Generation, LLC*, Petition Nos. IV-2008-1 & IV-2008-2 (Order on Petition) (December 15, 2009).
[47] A copy of the 1990 Workshop Manual is available at http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf. There is another draft version of the 1990 Workshop Manual that has jigsaw puzzle pieces on the cover, is not available online, and has some minor differences from the online version. For ease of reference, any citations to the 1990 Workshop Manual in this document refer to the version that is available at the link provided above.

expanded upon them. Thus, EPA recommends that permitting authorities seeking more detailed guidance on particular aspects of the top-down BACT process take care to consider more recent EPA actions (many of which are referenced in this document) in addition to the discussions in the 1990 Workshop Manual.[48]

Since the BACT provisions in the CAA and EPA's rules provide discretion to permitting authorities, a critical and essential component of a successful BACT analysis (whether it follows the top-down process or another approach) is the record supporting the decisions reached by the permitting authority. Permitting authorities should ensure that the BACT requirements contained in the final PSD permit are supported and justified by the information and analysis presented in a thorough and complete permit record. The record should clearly explain the reasons for selection or rejection of possible control and emissions reductions options and include appropriate supporting analysis.[49] In accordance with relevant statutory and regulatory requirements, the permitting authority must also provide notice of its preliminary decision on a source's application for a PSD permit and an opportunity for the public to comment on that preliminary decision. Thus, the record must also reflect careful consideration and response to each significant consideration raised in public comments. Each BACT analysis must be supported by a complete permitting record that shows consideration of all the relevant factors.

This guidance (including the appendices) provides some preliminary EPA views on some key issues that may arise in a BACT analysis for GHGs. It is important to recognize that this document does not provide any final determination of BACT for a particular source, since such determinations can only be made by individual permitting authorities on a case-by-case basis after consideration of the record in each case. Upon considering the record in an individual case, if a permitting authority has a reasoned basis to address particular issues discussed in this document in a different manner than EPA recommends here, permitting authorities (including EPA) have the discretion to do so in decisions on individual permit applications consistent with the relevant requirements in the CAA and regulations. Thus, depending on the relevant facts and circumstances, permitting authorities have the discretion to establish BACT limitations that are more or less stringent than levels that might appear to result if one were to follow the recommendations in this guidance.

Relationship of BACT and New Source Performance Standards (NSPS)

The CAA specifies that BACT cannot be less stringent than any applicable standard of performance under the New Source Performance Standards (NSPS).[50] As of the date of this guidance, EPA has not promulgated any NSPS that contain emissions limits for GHGs. EPA has developed this permitting guidance and associated technical "white papers"[51] to support initial

[48] See the collections of PSD guidance provided in footnote 2, *supra*.

[49] *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 131 (EAB 1999) ("The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record."); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 224-25 (EAB 2000) (remanding BACT limitation where permit issuer failed to provide adequate explanation for why limits deviated from those of other facilities).

[50] 42 USC 7479(3).

[51] These technical "white papers", targeting specific industrial sectors, provide basic information on GHG control options to assist states and local air pollution control agencies, tribal authorities and regulated entities implementing measures to reduce GHG, particularly in the assessment of best available control technology (BACT) under the PSD

BACT determinations for GHGs that will need to be made without the benefit of having an NSPS and supporting technical documents to inform the evaluation of the performance of available control systems and techniques.

To the extent EPA completes an NSPS for a relevant source category, BACT determinations that follow will need to consider the levels of the GHG standards and the supporting rationale for the NSPS. The process of developing NSPS and considering public input on proposed standards will advance the technical record on GHG control strategies and may reflect advances in control technology or reductions in the costs or other impacts of using particular control strategies. Thus, the guidance in this document should be viewed taking into consideration the potential development of an NSPS for a particular source category. In addition, the fact that a NSPS for a source category does not require a more stringent level of control does not preclude its consideration in a top-down BACT analysis.

Importance of Energy Efficiency

As discussed in greater detail below, EPA believes that it is important in BACT reviews for permitting authorities to consider options that improve the overall energy efficiency of the source or modification – through technologies, processes and practices at the emitting unit. In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per unit of output basis. For example, coal-fired boilers operating at supercritical steam conditions consume approximately 5 percent less fuel per megawatt hour produced than boilers operating at subcritical steam conditions.[52] Thus, considering the most energy efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated NSR pollutants (*e.g.*, NO_X, SO_2, $PM/PM_{10}/PM_{2.5}$, CO, etc.). Thus, it is also important to emphasize that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs). Additional considerations concerning energy efficiency in the determination of BACT for GHGs are discussed in more detail below.

An available tool that is particularly useful when assessing energy efficiency opportunities and options is performance benchmarking. Performance benchmarking information, to the extent it is specific and relevant to the source in question, may provide useful information regarding energy efficient technologies and processes for consideration in the BACT assessment. Comparison of the unit's or source's energy performance with a benchmark may highlight the need to assess additional energy efficiency possibilities. To the extent that benchmarking an emissions unit or source shows it to be a poor-to-average performer, the permitting authority may need to document and evaluate whether greater efficiencies are achievable. To ensure that the source is constructed and operated in a manner consistent with achieving the energy efficiency goals determined to be BACT, consideration should be given to

permitting program. These papers provide basic technical information that may be useful in a BACT analysis but they do not define BACT for each sector.

[52] U.S. Department of Energy, *Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL-2007/1281, Final Report, Revision 1 (August 2007) at 6 (finding that the absolute efficiency difference between supercritical and subcritical boilers is 2.3% (39.1% compared to 36.8%), which is equivalent to a 5.9% reduction in fuel use), *available at* http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf.

In the context of a technical feasibility analysis, the terms "availability" and "applicability" relate to the use of technology in a situation that appears similar even if it has not been used in the same industry. Specifically, EPA considers a technology to be "available" where it can be obtained through commercial channels or is otherwise available within the common meaning of the term.[90] EPA considers an available technology to be "applicable" if it can reasonably be installed and operated on the source type under consideration. Where a control technology has been applied on one type of source, this is largely a question of the transferability of the technology to another source type. A control technique should remain under consideration if it has been applied to a pollutant-bearing gas stream with similar chemical and physical characteristics. The control technology would not be applicable if it can be shown that there are significant differences that preclude the successful operation of the control device. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review.

Evaluations of technical feasibility should consider all characteristics of a technology option, including its development stage, commercial applications, scope of installations, and performance data. The applicant is responsible for providing evidence that an available control measure is technically infeasible. However, the permitting authority is responsible for deciding technical feasibility. The permitting authority may require the applicant to address the availability and applicability of a new or emerging technology based on information that becomes available during the consideration of the permit application.

Information regarding what vendors will guarantee should be considered in the BACT selection process with all the other relevant factors, such as BACT emission rates for other recently permitted sources, projected cost and effectiveness of controls, and experience with the technology on similar gas streams. Commercial guarantees are a contract between the permit applicant and the vendor to establish the risk of non-performance the vendor is willing to accept, and they typically establish the remedy for failure to perform and the test methods for acceptance. A permit applicant uses these guarantees to provide its investors and lenders with reasonable assurances that the proposed facility will reliably perform its intended function and consistently meet the proposed permit limits. While permit applicants use these guarantees as protection from overly optimistic vendor claims for new technologies, experience demonstrates that these terms and conditions can also be customized for each circumstance to imply greater or lesser performance, depending on the stringency of the guarantees and associated penalties for nonperformance. The willingness of vendors to provide guarantees and the limits of these guarantees can be an important factor in determining the level of performance specified in a PSD permit. A vendor guarantee of a certain level of performance may be considered by the permitting authority later in the BACT process when proposing a specific emissions limit or level of performance in the PSD permit. However, a control technology should not be eliminated in Step 2 of the top-down BACT process based solely on the inability to obtain a commercial guarantee from a vendor on the application of technology to a source type.

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[90] *In re Cardinal FG Company*, 12 E.A.D. at 14; *In re Steel Dynamics, Inc.*, 9 E.A.D. at 199.

Further, a technology should not be eliminated as technically infeasible due to costs. Where the resolution of technical difficulties is a matter of cost, this analysis should occur in BACT Step 4.

GHG-Specific Considerations

EPA's historic approach to assessing technical feasibility that is summarized above and described in the 1990 Workshop Manual and subsequent actions such as EAB decisions is generally applicable to GHGs. The nature of the concerns and remedies arising from identification of available technologies is well-explained in the 1990 Workshop Manual and other referenced documents. However, technologies available for controlling traditional pollutants were, in many cases, well-developed at the time that the 1990 Workshop Manual was drafted. Similarly, we expect the commercial availability of different GHG controls to increase in the coming years. Permitting authorities need to make sure that their decisions regarding technical infeasibility are well-explained and supported in their permitting record, paying particular attention to the most recent information from the commercial sector and other recently-issued permits.

This guidance is being issued at a time when add-on control technologies for certain GHGs or emissions sources may be limited in number and in various stages of development and commercialization. A number of ongoing research, development, and demonstration programs may make CCS technologies more widely applicable in the future.[91] These facts are important to BACT Step 2, wherein technically infeasible control options are eliminated from further consideration. When considering the guidance provided below, permitting authorities should be aware of the changing status of various control options for GHG emissions when determining BACT.

In the early years of GHG control strategies, consideration of commercial guarantees is likely to be involved in the BACT determination process. This type of guarantee may be more relevant for certain GHG controls because, unlike other pollutants with available, proven control technologies, some GHG controls may have a greater uncertainty regarding their expected performance. As noted above, the lack of availability of a commercial guarantee, by itself, is not a sufficient basis to classify a technology as "technologically infeasible" for BACT evaluation purposes, even for GHG control determinations.

As discussed earlier, although CCS is not in widespread use at this time, EPA generally considers CCS to be an "available" add-on pollution control technology for facilities emitting CO_2 in large amounts and industrial facilities with high-purity CO_2 streams. Assuming CCS has been included in Step 1 of the top-down BACT process for such sources, it now must be evaluated for technical feasibility in Step 2. CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant

[91] For example, the U.S. Department of Energy has a robust CCS research, development, and demonstration program supported by annual appropriations and \$3.4B of Recovery Act funds. See www.fe.doe.gov.

concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (*e.g.,* space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).

While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard. Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.

The level of detail supporting the justification for the removal of CCS in Step 2 will vary depending on the nature of the source under review and the opportunities for CO_2 transport and storage. As with all top-down BACT analyses, cost considerations should not be included in Step 2 of the analysis, but can be considered in Step 4. In circumstances where CO_2 transportation and sequestration opportunities already exist in the area where the source is, or will be, located, or in circumstances where other sources in the same source category have applied CCS in practice, the project would clearly warrant a comprehensive consideration of CCS. In these cases, a fairly detailed case-specific analysis would likely be needed to dismiss CCS. However, in cases where it is clear that there are significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review (*e.g.,* sources that emit CO_2 in amounts just over the relevant GHG thresholds and produce a low purity CO_2 stream) a much less detailed justification may be appropriate and acceptable for the source. In addition, a permitting authority may make a determination to dismiss CCS for a small natural gas-fired package boiler, for example, on grounds that no reasonable opportunity exists for the capture and long-term storage or reuse of captured CO_2 given the nature of the project. That finding may be sufficient to dismiss CCS for similar units in subsequent BACT reviews, provided the facts upon which the original finding was made also apply to the subsequent units and are still valid.

D. BACT Step 3 – Ranking of Controls

General Concepts

After the list of all available controls is winnowed down to a list of the technically feasible control technologies in Step 2, Step 3 of the top-down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (*i.e.*, the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the top-down BACT selection process in Step 4.[92]

In determining and ranking technologies based on control effectiveness, applicants and permitting authorities should include information on each technology's control efficiency (*e.g.*, percent pollutant removed, emissions per unit product), expected emission rate (*e.g.*, tons per year, pounds per hour, pounds per unit of product, pounds per unit of input, parts per million), and expected emissions reduction (*e.g.*, tons per year). The metrics chosen for ranking should best represent the array of control technology alternatives under consideration. While input-based metrics have traditionally been the preferred ranking format for many BACT analyses, for some source types, particularly combustion sources, it may be more appropriate to rank control options based on output-based metrics that would fully consider the thermal efficiency of the options when determining control effectiveness. In particular, where the output of the facility or the affected source is relatively homogeneous, an output-based standard (*e.g.*, pounds per megawatt hour of electricity, pounds per ton of cement, etc.) may best present the overall emissions control of an array of control options. Where appropriate, net output-based standards provide a direct measure of the energy efficiency of an operation's emission-reducing efforts. However, in the simple case of a new or modified fuel-fired unit, the thermal efficiency of the unit can be a useful ranking metric. Furthermore, when the output of the facility is a changing mix of products, an output-based standard may not be appropriate.

GHG-Specific Considerations

As discussed in earlier sections, the options considered in a BACT analysis for GHG emissions will likely include, but not necessarily be limited to, control options that result in energy efficiency measures to achieve the lowest possible emission level. Where plant-wide measures to reduce emissions are being considered as GHG control techniques, the concept of overall control effectiveness will need to be refined to ensure the suite of measures with the lowest net emissions from the facility is the top-ranked measure. Ranking control options based on their net output-based emissions ensures that the thermal efficiency of the control option, as well as the power demand of that control measure, is fully considered when comparing options in Step 3 of the BACT analysis.

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[92] EPA has previously recommended that Step 3 of a BACT analysis include an assessment of the energy, environmental, and economic impacts of each remaining option on the list. See 1990 Workshop Manual at B.25. However, the energy, environmental, and economic impacts of the control options are not actually compared until Step 4 of the process. See 1990 Workshop Manual at B.26. Thus, the compilation of this information can be accomplished in either Step 3 or Step 4 of the process.

modeling and evaluations of risks and impacts of GHG emissions currently is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying these exact impacts attributable to the specific GHG source obtaining a permit in specific places is not currently possible with climate change modeling. Given these considerations, an assessment of the potential increase or decrease in the overall level of GHG emissions from a source would serve as the more appropriate and credible metric for assessing the relative environmental impact of a given control strategy. Thus, when considering the trade-offs between the environmental impacts of a particular level of GHG reduction and a collateral increase in another regulated NSR pollutant, rather than attempting to determine or characterize specific environmental impacts from GHGs emitted at particular locations, EPA recommends that permitting authorities focus on the amount of GHG emission reductions that may be gained or lost by employing a particular control strategy and how that compares to the environmental or other impacts resulting from the collateral emissions increase of other regulated NSR pollutants.

In determining how to value or weigh any trade-offs in emissions for regulated pollutants (including GHGs), permitting authorities should continue to focus on "significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative."[111] Relatively small collateral increases of another pollutant need not be of concern, unless even that small increase would be significant, such as a situation where an area is close to exceeding a NAAQS or PSD increment and the additional increase could push the area into nonattainment. Thus, to assess the significance of an emissions increase or decrease, a permitting authority should give some consideration to the impacts of a given amount of emissions. However, permitting authorities need not consider every possible environmental endpoint impact of every conceivable technology. The top-down BACT process calls for evaluating only those control alternatives that remain under consideration at BACT Step 4 of the analysis. Thus, when a trade-off is present, permitting authorities may limit their consideration of environmental impacts to only to those control options in which the comparison of GHG emissions to other regulated NSR pollutants might actually lead to a different selection of BACT for that facility.

With respect to the evaluation of the economic impacts of GHG control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system. As with all evaluations of economics, a permitting authority should explain its decisions in a well-documented permitting record.

EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in

[111] *In re Hillman Power,* 10 E.A.D. at 684.

Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO_2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4. In addition, as a result of the ongoing research and development described in the Interagency Task Force Report noted above, CCS may become less costly and warrant greater consideration in Step 4 of the BACT analysis in the future.

As in the past for criteria pollutant BACT determinations, the final decision regarding the reasonableness of calculated cost effectiveness values will be made by the permitting authority. This decision is typically made by considering previous regulatory and permitting decisions for similar sources. As noted above, to justify elimination of a control option on economic grounds, the permit applicant should demonstrate that the costs of pollutant removal for the particular option are disproportionately high. However, given that there is little history of BACT analyses for GHG at this time, there is not a wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT. As the permitting of sources of GHG progresses and more experience is gained, additional data to determine what is cost effective in the context of individual permitting actions will become known and should be included in the RBLC. We note, however, that when looking at pollutants historically regulated under the PSD Program, such as criteria pollutants, the cost effectiveness of a control device is based on a significantly lower volume of emissions than the amount of emissions that are emitted by most sources of GHGs. For example, a new boiler that is subject to the NSPS and emits 250 TPY of NO_X will emit well above 100,000 TPY of CO_2e. As a result, even taking account of the current limited data and consequent uncertainty concerning the costs of GHG BACT, it is reasonable to anticipate that the cost effectiveness numbers (in \$/ton of CO_2e) for the control of GHGs will be significantly lower than those of the cost effectiveness values for controls of criteria pollutants that have evolved over time.[112]

With respect to energy impacts in a BACT analysis for GHGs, the relative energy demands of the options under consideration for reducing emissions from the facility obtaining a permit should be considered when weighing options for reducing direct emissions of GHGs in Step 4 of the analysis, regardless of the location where the thermal or electrical energy for the facility is produced. This analysis should include an assessment of how particular control options for GHGs may impact the amount of energy that must be produced at an offsite location to support the operation of the facility obtaining the permit. Given the potential emissions from generation of electricity, such impacts may also be considered in the context of environmental impacts.[113]

Permitting authorities also have flexibility when evaluating the trade-offs between energy, environmental, and economic impacts. In selecting a technology for GHG control, a

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[112] For consistency purposes, cost effectiveness for GHG control options should be based on dollars per ton of CO_2e removed, rather than total mass or mass for the individual GHGs.
[113] As discussed above in the section on Step 1, energy efficiency improvements that only function to reduce the secondary emissions associated with offsite combustion to produce energy at another location should not be considered as options in the BACT analysis under existing EPA interpretations of its regulations.

**Standards of Performance for
Fossil-Fuel-Fired Steam Generating Units for Which
Construction Is Commenced After August 17, 1971
(40 CFR 60 subpart D)**

**Standards of Performance for
Electric Utility Steam Generating Units for Which
Construction Is Commenced After September 18, 1978
(40 CFR 60 subpart Da)**

**Standards of Performance for
Industrial-Commercial-Institutional Steam Generating Units
(40 CFR 60 subpart Db)**

**Standards of Performance for Small
Industrial-Commercial-Institutional Steam Generating Units
(40 CFR 60 subpart Dc)**

**Response to Public Comments on
Rule Amendments Proposed May 3, 2011 (73 FR 33642)**

US Environmental Protection Agency
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, NC 27711

December 2011

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Acronyms and Abbreviations

BACT	Best Available Control Technology
BSER	Best System of Emission Reduction
BLD	Bag leak detection
Btu	British thermal unit
CAA	Clean Air Act
CCS	Carbon capture and storage
CEMS	Continuous emissions monitoring system
CFB	Circulating fluidized bed
CHP	Combined heat and power
CO	Carbon monoxide
COMS	Continuous opacity monitoring system
CROMERR	Cross-Media Electronic Reporting Regulation
DOE	U.S. Department of Energy
EGU	Electric steam generating unit
EPA	U.S. Environmental Protection Agency
ERT	Electronic Reporting Tool
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
GHG	Greenhouse gas
IGCC	Integrated gasification combined cycle
kWh	Kilowatt-hour
MW	Megawatt
MWC	Municipal waste combustor
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
OMB	Office of Management and Budget
PM	Particulate matter
PRA	Paperwork Reduction Act
PSD	Prevention of Significant Deterioration
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SO_x	Sulfur oxides

1. Introduction

On February 27, 2006, the United States Environmental Protection (EPA) promulgated amendments (71 FR 9866) to the new source performance standards (NSPS) for electric utility steam generating units (EGUs) under 40 CFR part 60 subparts D and Da. EPA was subsequently sued by the offices of multiple state Attorneys General and environmental organizations on these amendments. On September 2, 2009, EPA was granted a voluntary remand without vacatur of the 2006 amendments. On May 3, 2011, EPA proposed amendments (76 FR 24976) in response to the voluntary remand. These amendments included proposed new emissions limits for particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_X) for EGUs that commence construction, reconstruction, or modification on or after May 3, 2011. As part of this action, the Agency also proposed several minor amendments, technical clarifications, and corrections to existing provisions applicable to the fossil fuel-fired EGUs under 40 CFR 60 subparts D and Da, as well as large and small industrial-commercial-institutional steam generating units NSPS under 40 CFR part 60 subparts Db and Dc.

A 90-day period ending August 4, 2011 was provided for the public to submit comments regarding the proposed subparts D, Da, Db, and Dc amendments. Approximately 200,000 comments were entered into EPA's Air and Radiation docket assigned for this NSPS rulemaking (number EPA-HQ-OAR-2011-0044). Many of these comments were duplicative of comments submitted to EPA's Air and Radiation docket assigned for the development of the proposed national emission standards for hazardous air pollutant (NESHAP) from coal- and oil-fired EGUs under CAA section 112 (number EPA-HQ-OAR-2009-0234).

EPA reviewed all of the comments entered into docket EPA-HQ-OAR-2011-0044 and grouped the commenters into three general categories. The first category is commenters submitting duplicative copies of comments also submitted to docket EPA-HQ-OAR-2009-0234 regarding the proposed NESHAP rulemaking, and which do not contain any comments specifically related to the proposed NSPS amendments. The second category consists of commenters stating only general support or opposition to the NSPS rulemaking. Commenters supporting the amendments frequently included statements requesting that EPA establish the most stringent air emissions standards possible for EGUs. Commenters opposing the amendments frequently stated that the proposed NSPS amendments are overly stringent and burdensome and would inhibit or prevent the construction of new coal-fired EGUs, thereby increasing costs for electricity. The third and final category of public commenters are those providing comments regarding specific issues and topics related to the rule development and proposed rule language for amendments to 40 CFR 60 subparts D, Da, Db, and Dc.

This document presents a summary of the public comments entered into docket EPA-HQ-OAR-2011-0044 regarding specific issues and topics related to the development of the proposed NSPS amendments to 40 CFR 60 subparts D, Da, Db, and Dc (i.e., comments submitted by commenters in the third category) and EPA's responses to those comments. The comment summaries pertaining to subparts D and Da are grouped by topic in Section 2 of this document. Comments pertaining to proposed amendments specific to subparts Db and Dc are included in Section 3. Tables 1 and 2 match the commenter to the docket entry number cited in Sections 2 and 3 for specific legal or technical comments. Some of the comment sets were signed or submitted on behalf of multiple commenters.

Table 1. List of Commenters Cited in this Summary Document Submitting Comments to EPA Air and Radiation Docket Number EPA-HQ-OAR-2011-0044 Regarding NSPS Rule Amendments Proposed May 3, 2011 (76 FR 24976)

EPA-HQ-OAR-2011-0044 Document No.	Date Submitted	Name and Affiliation
4634	August 4, 2011	James S. Pew Earthjustice
4635	August 4, 2011	Thomas C. Perry National Mining Association
4656	August 4, 2011	William D. Bissett Kentucky Coal Association
4673	August 4, 2011	Reid T. Clemmer PPL Services Corporation
4674	August 4, 2011	Martha E. Rudolph State of Colorado Colorado Department of Public Health and Environment
4686	August 4, 2011	John T. Heard The Virginia Coal Association
4698	August 2, 2011	Ronald A. Amirikian State of Delaware Department of Natural Resources & Environmental Control
4712	August 4, 2011	John M. McManus American Electric Power
4713	August 4, 2011	William O'Sullivan State of New Jersey Division of Environmental Protection
4714	August 4, 2011	Mark R. Vickery State of Texas Texas Commission on Environmental Quality
4715	August 4, 2011	Erika Padgett Elizabeth Wheeler Clean Wisconsin Kim Wright Midwest Environmental Advocates Peter Bakken Wisconsin Interfaith Power and Light George Meyer Wisconsin Wildlife Federation
4760	August 3, 2011	Jolene M. Thompson American Municipal Power, Inc.
4765	August 4, 2011	Alex Hofmann Theresa Pugh American Public Power Association
4766	August 4, 2011	Chris M. Hobson Southern Company
4768	August 3, 2011	James A. Landreth SCE&G
4770	August 3, 2011	Desi M. Chari The Dow Chemical Company
4830	August 4, 2011	Rae E. Cronmiller National Rural Electric Cooperative Association
4832	August 4, 2011	Kathleen L. Barrón Exelon Corporation

EPA-HQ-OAR-2011-0044 Document No.	Date Submitted	Name and Affiliation
4833	August 4, 2011	JoAnne Rau Randal Griffin Dayton Power and Light Company
4834	August 4, 2011	Jay Hudson Santee Cooper
4836	August 4, 2011	F. William Brownell Craig S. Harrison Lauren Freeman Hunton & Williams LLP Counsel to the Utility Air Regulatory Group (UARG)
4839	August 4, 2011	Verne Shortell NRG Energy, Inc.
4841	August 4, 2011	Robert D. Bessette Council of Industrial Boiler Owners
4893	August 4, 2011	Tom Thompson, Eco Power Solutions (USA) Corp
4926	August 4, 2011	Lisa Jacobson The Business Council for Sustainable Energy
4984	August 4, 2011	Brian H. Moeck The Large Public Power Council
4985	August 4, 2011	Raymond L. Evans FirstEnergy Corporation
4989	August 4, 2011	John M. McManus American Electric Power
4997	August 4, 2011	Les Oakes Cynthia AM Stroman King & Spalding LLP Counsel to The IPP Coalition
5000	August 4, 2011	John L. Stowell Duke Energy
5074	August 4, 2011	David Gardiner Alliance for Industrial Efficiency
5075	August 4, 2011	Caroline Choi Progress Energy
5077	August 4, 2011	John W. Myers Tennessee Valley Authority
5087	August 4, 2011	Raymond L. Evans FirstEnergy
5089	August 4, 2011	Thomas C. Perry National Miming Association
5208	August 3, 2011	G. Vinson Hellwig State of Michigan Department of Environmental Quality
5195	August 4, 2011	Kerry Kelly Waste Management
5210	August 4, 2011	Susanne Brooks Elena Craft Mark MacLeod Hilary Sinnamon Mandy Warner Peter Zalzal Environmental Defense Fund

EPA-HQ-OAR-2011-0044 Document No.	Date Submitted	Name and Affiliation
5240	August 4, 2011	Michael J. Nash Gulf Coast Lignite Coalition
5279	August 3, 2011	Eric Redman Summit Texas Clean Energy, LLC
5470	August 3, 2011	Mark J. Sadlacek Los Angeles Department of Water and Power
5477	August 15, 2011	Williw R. Taylor U.S. Department of the Interior
5715	August 4, 2011	Ann Brewster Weeks Clean Air Task Force Sanjay Narayan Sierra Club James S. Pew Earthjustice John Walke Natural Resources Defense Council Janice E. Nolen American Lung Association John Suttles Southern Environmental Law Center Joseph Mendelson III National Wildlife Federation Justin Bloom Scott Edwards Waterkeeper Alliance
5749	July 20, 2011	Myra C. Reece State of South Carolina Bureau of Air Quality, South Carolina Department of Health and Environmental Control
17620 in Docket No. EPA–HQ–OAR–2009–0234	August 4, 2011	S. William Becker National Association of Clean Air Agencies
17622 in Docket No. EPA–HQ–OAR–2009–0234	August 4, 2011	David Foerter Institute of Clean Air Companies
17711 in Docket No. EPA–HQ–OAR–2009–0234	August 4, 2011	Paul Noe and Robert Glowinski American Forest & Paper Association (AF&PA) and American Wood Council (AWC)
17755 in Docket No. EPA–HQ–OAR–2009–0234	August 3, 2011	Eddie Terrill State of Oklahoma Oklahoma Department of Environmental Quality
17852 in Docket No. EPA–HQ–OAR–2009–0234	August 4, 2011	Gregory C. Staple American Clean Skies Foundation (ACSF)
17878 in Docket No. EPA–HQ–OAR–2009–0234	August 4, 2011	Ben Yamagata Coal Utilization Research Council
17975 in Docket No. EPA–HQ–OAR–2009–0234	August 4, 2011	Environmental Integrity Project Eric Schaeffer

2. Response to Comments on Proposed NSPS Amendments to Subparts D and Da

2.1 General NSPS Rule Development

2.1.1 Fuel and Technology Neutral Approach for Rule Development

Comment: One commenter (4698) stated support for EPA's decision to adopt a fuel and technology neutral approach to developing the NSPS for new EGUs because it potentially facilitates the selection of a cleaner fuel as part of the overall integrated emissions compliance strategy, and provides flexibility in the design, construction, and operation of the unit in a configuration optimized for a given EGU. One commenter (5210) stated that "fuel neutral" standards should be based on the cleanest burning fuels instead of EGUs that burn pulverized coal, which EPA has used as the basis for the proposed emissions limits. According to the commenter, this approach violates the intent of Congress under Clean Air Act (CAA) section 111 that NSPS for new sources be forward looking and technology forcing. Many commenters (4766, 4830, 4834, 4948, 5077, 17878) oppose using a fuel and technology neutral approach to developing NSPS for EGUs, and instead recommend developing standards based on technology that account for the type of fuel burned. One commenter (4766) stated that EPA has no basis for developing "fuel neutral" standards in which all coal-, gas-, and oil-fired EGUs are subject to identical NSPS emissions limits. This approach unlawfully fails to consider the differences among boilers using different fuel types. Congress gave EPA the authority to "distinguish among classes, types, and sizes" when establishing standards; EPA, therefore, has an obligation to explain how it is applying the CAA Section 111 criteria to each fuel type, and to explain the national policy implications of its choices. A third commenter (4830) stated that it is bad public policy for NSPS to effectively eliminate whole categories of generation types, pollution control devices, and fuels. Diversities in generation design are critical to optimizing a facility for its specific and intended use. For example, fluidized bed combustion (FBC) is an ideal technological choice for intermediate-sized generation, and can utilize a broad array of fuels, from biomass to coal of different ranks. On the other hand, pulverized coal (PC) units have generally less fuel flexibility but are better suited for larger generation uses and can be designed to have superior thermal efficiency. An NSPS that effectively precludes coal, a particular coal rank, or combustion design is in effect tailoring the nation's future options for electric generation. CAA Section 111's statutory provisions are directed at disseminating the best system of emission reduction (BSER) throughout an identified source category and not for the purposes of significantly narrowing the nation's choices for types of steam electric generation and fuel to power it.

Response: The vast majority of subpart Da affected facilities burn coal as the primary fuel. It is within EPA's authority under the CAA to establish fuel and technology neutral standards. (See, for example, Lignite Energy Council v. EPA, 198 F.3d 930 (D.C. Cir. 1999)). It is also within EPA's authority to subcategorize standards based on fuel and boiler type. Whichever approach EPA chooses, it is appropriate for it to establish standards for EGUs that allow the use of inherently cleaner burning fuels to comply with the standards. The amended NO_X and PM standards for EGUs are largely fuel neutral, since the achievable emissions rate for the best system of emission reduction (BSER) is similar across boiler and fuel types. While the amended SO_2 standard does not establish separate standards based on coal rank, it does account for the impact of fuels with inherently high sulfur concentrations on the performance of the BSER technology by providing an alternate percent reduction standard. EPA has concluded that the amended standards allow affected EGUs the flexibility to use the boiler design and fuel types that best meet the site-specific needs of the EGU owner and operator. All of the amended standards have been achieved by primary boiler types (pulverized coal and fluidized beds) and across all coal ranks. Under the adopted fuel neutral approach, owners/operators of affected EGUs have the flexibility to build new units designed to use a cleaner burning fuel as an alternative to installing post-combustion emission control technology or to co-fire cleaner burning fuels with coal and install slightly less-efficient post combustion control technology.

Neither natural gas nor distillate oil is typically used in new baseload steam generating units (e.g., boilers with steam turbines). Basing the standards on either of these fuels would result in standards that are neither technically or economically achievable for a coal-fired EGU. Basing the amended standards on the use of natural gas would preclude the development of new coal-fired EGUs since the standards would not be technically achievable, even with the application of IGCC technology. Natural gas-fired EGUs have demonstrated annual NO_X emission rates of less than 0.40 lb/MWh gross output without the use of post combustion controls. This level has not been demonstrated to be achievable for any coal-fired EGUs even when using the best controls. In addition, natural gas and distillate oil have trace amounts of ash and sulfur and correspondingly low PM and SO_2 emission rates. Therefore, basing the NSPS on these PM and SO_2 emission rates would not be achievable for coal-fired EGUs with any technology EPA is aware of. If the NSPS were to essentially prohibit the construction of new coal-fired EGUs, the regulated community might stop development of promising control technologies, including carbon capture and storage, which can be used on existing coal-fired EGUs in addition to new coal-fired EGUs.

EPA has concluded that it is appropriate to continue to allow the construction of properly controlled coal-fired baseload EGU since, such an approach to generating electricity may be the most appropriate approach, from both a technical and financial perspective, in specific circumstances. Basing the standards on what is achievable by BSER employed on a coal-fired unit accomplishes this. EPA has concluded that the use of natural gas and distillate oil will play a dominant role in the future generation of electricity. Rather than burning natural gas or distillate oil in a boiler based EGU, however, we believe that any new baseload electric generation based on the use of either of these fuels would use combined cycle combustion turbines. Combustion turbines burning natural gas and distillate oil generate power more efficiently and economically than a boiler burning natural gas or distillate oil. The efficiency and capital cost benefits of combined cycle facilities outweigh the fact that natural gas and distillate oil are significantly more expensive per unit heat input than coal.

Comment: Several commenters (4836, 4997) stated that IGCC technology is inherently different from other coal-based electric generation technologies and should be regulated separately. The NSPS applicable to IGCC EGUs should address the unique characteristics of IGCC technology. Factors that should be examined to properly consider the design and operational characteristics of IGCC technology include: 1) operating scenarios in which the IGCC EGUs (combustion turbines and duct burner) are combusting different fuels or a combination of fuels, such as natural gas, coal or other carbonaceous compound (petroleum coke, biomass, municipal solid waste, etc.), derived syngas, and/or syngas produced off-site; 2) the applicability of any work practice and fuel sampling provisions as they relate to the design and operation of IGCC EGUs; and 3) the use of heat input and generation output terminology specific to IGCC EGUs.

Response: EPA has concluded that the language is sufficiently clear that the output from an IGCC facility is the combination of the output from the combustion turbine, steam turbine, and any useful thermal output. The heat input to an IGCC facility is the combined heat input to the combustion turbine engine and any fuel input to the duct burners in the heat recovery steam generator. For an IGCC facility that does not coproduce hydrogen or carbon containing chemicals, this value should be close to the energy content of the raw coal input to the gasification system (greater than 95%).

The gasification/purification system should be designed to provide a uniform syngas regardless of the feedstock so it is unclear how the feedstock would impact emissions. The commenter did not provide data indicating that the use of natural gas during periods when the gasification system is not providing syngas would create compliance problems. On the contrary, combined cycle facilities would only need to maintain a NO_X emissions rate of 25 ppm to comply with the amended NO_X standard. This emissions rate is routinely achieved by both combustion turbines using dry low NO_X combustion controls and natural gas-fired diffusion flame combustion turbines using water or steam injection. The combustion of natural gas also results in minimal SO_2 and PM emissions. Post combustion controls would not be required to maintain compliance with any of the emission standards.

Comment: One commenter (5210) stated that high thermal efficiency should be used to establish standards, instead of being considered a control technology. In EPA's current proposed amendments to the NSPS, there is no discussion of thermal efficiency or what efficiency rate was used by the Agency to determine the new standards. The commenter requests that EPA explain in the final rule what thermal efficiency assumptions were used in determining the new NSPS, and whether they are different from the assumptions used in the last amendments. The commenter also recommends that EPA use the greatest feasible thermal efficiency for EGUs as an input to determine the NSPS.

Response: The facilities used to establish the output-based standards included some of the most thermal efficient facilities. Therefore, the emission standards account for both high thermal efficiency and the efficiency of the emissions control equipment. This is the preferred approach when sufficient data is available, and simultaneously accounts for both the thermal efficiency and control equipment efficiency under various operating conditions. We consequently concluded it is not necessary to measure emissions on a heat input basis and then use an assumed efficiency to convert to an output-based standard, but rather directly established output-based standards based on the performance of the best performing facilities.

Comment: One commenter (5240) stated that separate NSPS must be established for the subcategory of EGUs burning coal with a heat input of less than 8,300 Btu/lb as was the case in EPA's proposed NESHAP standards. According to the commenter, emissions of air pollutants, especially PM and SO_2, are significantly different when burning these types of coal and must be reflected in any applicable NSPS.

Response: The proposed NESHAP subcategory mentioned by the commenter was for Hg and not acid gases or total metals. The commenter provided neither emissions data indicating a subcategory for low Btu fuel such as lignite would be appropriate nor data indicating that SO_2 and PM controls do not work effectively with all types of coal. Fabrics filters, the selected BSER for control of PM emissions, are designed to control emissions to a specified outlet concentration and operate relatively independent of the PM concentration coming into the baghouse. The SO_2 standard has an alternate percent reduction requirement that specifically accounts for the use of high sulfur fuels. In addition, various coal cleaning, upgrading, and drying technologies for low rank coals reduce the ash, sulfur, and moisture content of these coals resulting in a fuel with characteristics similar to that of higher rank coals.

The following are several examples of existing EGUs which demonstrate that the amended SO_2 and PM standards are achievable for low rank coals:

1. The Sandow 5B facility is a subcritical lignite-fired fluidized bed EGU and is presently operating below the amended SO_2 % reduction alternative. Furthermore, both Sandow 5A and 5B are operating below the amended PM standard of 0.090 lb/MWh.

2. The Oak Grove 1 and 2 facilities are supercritical lignite-fired pulverized coal EGUS. Both are presently operating below the amended numerical SO_2 standard, and the Oak Grove 2 facility is also operating below the amended SO_2 % reduction requirement.

3. The Milton R. Young B1 and B2 facilities are subcritical lignite-fired cyclone boiler EGUs. Both are operating below the amended PM standard of 0.090 lb/MWh.

2.1.2 Selection of Best System of Emission Reduction (BSER)

2.1.2.1 Consideration of EGU Energy Efficiency in Selection of BSER

Comment: One commenter (4634) stated that EPA's failure to set NSPS emissions limits for PM, SO_2, and NO_X reflecting the use of energy-efficient design is unlawful and arbitrary. New coal-fired EGUs can significantly reduce emissions of all pollution emitted by incorporating energy-efficient design (e.g., use of supercritical boilers), allowing them to produce more electricity from burning a given amount of coal. To satisfy the directives of CAA section 111, EPA must assume a higher efficiency in combination with emissions controls to impose more stringent emissions limits for PM, SO_2 and NO_X. The commenter questions EPA basing the proposed output-based emissions limits on gross electrical generating efficiency of 36 percent, which the commenter contends is not BSER as required by the CAA. The commenter states that 25 percent of existing EGUs achieve this generating efficiency, or higher and new EGUs can achieve net efficiencies as high as 45 percent.

Response: Efficiency has already been accounted for because the facilities used to establish the amended standards include some of the highest efficiency supercritical facilities and the output-based standards were directly established based on the performance of the best performing facilities. The comment referring to an assumed efficiency of 36% is unclear and appears to refer to the approach taken in previous amendments to subpart Da. The analysis in this rulemaking looked at actual out-put based emissions data and, therefore, it was not necessary to assume a gross efficiency.

2.1.2.2 Consideration of IGCC Technology in Selection of BSER

Comment: One commenter (5715) stated that integrated gasification combined cycle (IGCC) technology is a demonstrated system of emissions control for EGUs and EPA should consider it in determining BSER to control PM, SO_2 and NO_X emissions from coal-fired EGUs. Another commenter (4997) stated that integrated gasification IGCC technology is a power generation technology and should not be identified as EGU emissions control.

Response: As stated in the proposal preamble, the benefits resulting from reduced emissions of criteria pollutants are not sufficient in all instances to justify the higher capital costs of today's IGCC units. According to the costs and emissions data available from the DOE, the annual costs of a 500 MW IGCC would be $71 million more than a comparable supercritical PC EGU. Even though the IGCC facility would reduce SO_2, NO_X, and PM emissions by 1,156 tons, 264 tons, and 102 tons respectively, the incremental costs are not justified as a basis for national requirements.

2.1.3 Net Energy Output Based Emissions Standards Format

Comment: Comments were received in support of and in opposition to EPA's proposal to require affected EGUs to meet the proposed NSPS for PM, SO_2, and NO_X using an emissions standards format that expresses limits as the allowable amount of pollutant emitted per net energy output by the affected EGU. Several commenters (5715, 5074, 5210) supporting the proposal stated that use of this format will encourage improvements in overall EGU facility energy efficiency, which results in lower air pollutant emissions and is an incentive to minimize parasitic energy demands from pollution control equipment (auxiliary energy demands is synonymous with parasitic energy demands). Many other commenters (4673, 4698, 4712, 4765, 4830, 4836, 4989, 4997, 5000, 5077, 5089, 5208, 17878) oppose the mandatory use of this format, stating that the NSPS should be based on limits on the allowable amount of air pollutant emitted per *gross* energy output by the affected EGU or on allowable amounts of air pollutants emitted per energy input to the affected EGU. Reasons cited by the commenters for their opposition to requiring mandatory compliance with net energy output based emissions standards include: 1) a significant amount of the parasitic power demands at coal-fired power plants is needed to operate the air pollution control equipment required to comply with air emissions standards; 2) there are monitoring difficulties in measuring net output, especially at facilities operating multiple EGUs; 3) parasitic loads vary on a individual EGU-by-EGU basis and, for a given EGU, on a duty cycle basis (e.g. as the load decreases on a typical EGU, the percent of parasitic power increases; 4) EGUs are not as thermally efficient at lower loads and consequently the amount of fuel that must be used increases on an electrical output basis; 5) at facilities with affected EGUs and also at older, less efficient EGUs which supply power to various auxiliaries throughout the plant, requiring the proposed net output-based NSPS on the affected EGU could actually decrease overall plant efficiency; and 6) a net output approach will be problematic with emerging technologies such as IGCC and certain greenhouse reduction technologies such as carbon capture and sequestration (CCS).

Response: One of the primary benefits of using net output-based standards is that it provides a more accurate measurement of the environmental impacts of specific EGUs. Net output-based standards recognize the environmental benefit of the minimization of auxiliary loads and operating the facility as efficiently as possible under all conditions. The comment about net output-based standards resulting in less efficient EGUs operating more than higher efficiency EGUs at locations with multiple facilities is unclear. The net output would be measured on an EGU-specific basis as the gross output from the EGU minus auxiliary loads specific to that EGU. If electric power from one EGU were being used to power the auxiliary equipment of a separate EGU then that power would have to be measured and properly accounted for. Due to the lack of net output-based emission rates for multiple types of EGUs with various control configurations over a range of operating conditions, the final rule allows, but does not require, the use of a net-output based standard as an alternative to the gross-output based standard. While gross output-based emission standards are not as accurate a measure of environmental impact as net output-based emission standards, they are superior to input-based emission standards.

The use of a gross output-based standard as it is presently defined does not provide sufficient monitoring to allow an accurate comparison of the environmental impact between different EGUs and recognize efficiency improvements. An EGU with electrically driven boiler feed pumps would have higher gross output than a facility that uses steam driven boiler feed pumps (steam driven feed pumps extract energy from the boiler steam prior to the generator). Consequently, the present definition could potentially drive the installation of electrically driven boiler feed pumps instead of steam driven boiler feed pumps. From an overall net efficiency basis, it is often more efficient to use steam driven boiler feed pumps. Electrically driven boiler feed pumps could account for as much as 3% of the gross electric output of a coal-fired EGU, substantially increasing the parasitic power requirements. Therefore, we are amending the definition of gross output for new facilities to be the gross output from the generator(s) minus any electric power requirements to drive the boiler feed pumps. Without this amendment, switching to a steam driven feed pump to improve net efficiency could appear to decrease gross efficiency. Since boiler feeds pumps are specific to individual boilers, the monitoring issues mentioned by the commenters are no longer applicable. In addition, the majority of larger EGUs use steam driven boiler feed pumps and would not be impacted by the amendment.

Furthermore, the primary parasitic power requirements for an IGCC facility that account for the primary differences between the net and gross efficiency with a PC boiler are the gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor). Correspondingly, the gross parasitic power requirements for an IGCC facility would also subtract out the electric power required to run these compressors. For facilities that coproduce chemicals, only a portion of the power would be subtracted from the gross output.

The use of net out-based standards is only an alternative. The comment about net output-based standards being problematic when use in conjunction with CCS is no longer relevant.

Comment: Several commenters (4698, 4766, 4768, 5000) disagree with EPA's proposal to calculate the net energy output for an EGU from the EGU's gross energy output, assuming a 5% parasitic electric load loss factor. Actual parasitic load can vary across EGUs depending on site-specific factors such as geographic location, EGU operating mode, and equipment selection. All of these factors affect a facility's overall auxiliary power load and hence its net energy output. Therefore, a uniform 5% assumption is inappropriate. One commenter (4698) recommends that EPA solicit input from EGU architect and engineering companies to develop auxiliary load estimates for a range of EGU sizes and configurations. Another commenter (4768) states that a 10% parasitic electric load loss factor would be a more representative value. One commenter's (5000) experience is that approximately 7 to 8% of a conventional coal fired station's power is required to run auxiliary equipment. The commenter believes that this is a more representative value across the industry considering that units generally will be operating with SCR, FGD, and PM emissions controls, all of which require auxiliary power. Also, if a CCS is used in the future, the amount of auxiliary power will dramatically increase.

Response: According to the National Energy Technology Laboratory in the document "Cost and Performance Baseline for Fossil Energy Plants," parasitic power requirements for pulverized coal-fired boilers using supercritical steam conditions varies from 5.2% for high rank coals to 5.9% for low rank coals. These estimates are based on detailed designs and are the best estimates available to EPA. However, in recognition that parasitic power requirements can increase in terms of percentage of load at lower loads the final rule uses a 7.5% parasitic load assumption.

Comment: One commenter (5210) states that output-based standards are only truly effective when determined by using output based data. The commenter requests that EPA not use input based data to set the NSPS standards and then simply convert those standards to output based numbers. Instead, the commenter recommends that EPA finalize output-based standards, based on output data, for all pollutants, regardless of whether compliance is based on performance tests or continuous emissions monitoring systems (CEMS).

Response: Output-based emissions data was used to establish the amended emissions standards.

2.1.4 Standards for Reconstructed and Modified EGUs

Comment: One commenter (5715) states that EPA's proposal to allow modified and reconstructed EGUs to meet less stringent NSPS emission limits than those required for new EGUs is not authorized by the CAA, and is therefore unlawful. The proposed NSPS for reconstructed and modified EGUs contradict Congressional intent that as existing sources are upgraded, they control their emissions to a rate reflecting best system of emission reduction for the industry. The commenter cites specific CAA sections and past court decisions to support this comment.

Response: Standards under section 111 of the Clean Air Act must be achievable See, National Lime Association v. EPA, 627 Fed. 2d 416 (D.C. Cir. 1980). With this in mind, we have concluded that section 111(b)(2)'s authorization to distinguish among classes, types and sizes when establishing NSPS allows us to establish a subcategory for modified sources in appropriate circumstances. See, Asarco v. EPA, 578 F.2d 319, 330 (D.C. Cir. 1978) (Leventhal, J. concurring) (explaining why the statute permits subcategorizing modified sources). Here, certain existing facility designs are not capable of operating combustion controls as effectively as newly designed facilities and, therefore, cannot achieve the same level of emissions reductions as newly designed facilities through the use of combustion controls. Further, even using the most efficient post combustion controls, these facilities are not able to achieve the same NO_X emissions rate as a newly designed facility. In determining what is achievable, EPA must consider costs and for modified facilities, the incremental cost effectiveness of adding a second scrubber to reduce SO_2 emissions beyond what is achievable by currently installed technology is not cost effective. The new source PM standard is based on the use of a fabric filter. Existing facilities potentially don't have adequate space available to cost effectively retrofit an existing ESP with a fabric filter.

2.1.5 Standards for Combined Heat and Power (CHP) Units Subject to NSPS

Comment: One commenter (5074) states that the net output-based standards in the NSPS should be modified in the final rule to account for both the thermal and electric generation from combined heat and power (CHP) and waste heat recovery systems subject to the NSPS. Absent this, the net output-based standards fail to account for (and incentivize) the full efficiency gains associated with such systems.

Response: Based upon comparison of the criteria pollutant emissions that would result from generating the thermal and electric output in separate facilities, EPA increased the thermal credit from 50% to 75% in 2006 (71 FR 9866). The definition is as follows:

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical or mechanical output **plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).**

Comment: EPA requested comment on, "whether it is appropriate to recognize the environmental benefit of electricity generated by CHP units by accounting for the benefit of on-site generation, which avoids losses from the transmission and distribution of the electricity." One commenter (5074) states that these avoided losses should be recognized because such savings are one of the key benefits of distributed generation. Several commenters (4926, 5074) state that that for CHP units subject to the NSPS, a 5% benefit for avoided transmission and distribution losses is too low. EPA should adopt a higher multiplier that fully credits the transmission and distribution savings of CHP and therefore incentivizes such investments.

Response: EPA acknowledges that overall transmission and line losses are closer to 10%. However, the CHP facilities typically covered by subpart Da are large facilities with relatively large amounts of the generated electricity being transmitted to other end users, and the benefits are reduced. Therefore, the 5% credit is reasonable and adequately recognizes the environmental benefit of CHP compared to separate electric and thermal generation.

2.1.6 NSPS during Periods of EGU Startup, Shutdown, and Malfunction

Comment: Comments were received in support of and in opposition to EPA' s proposal that NSPS emission limits apply at all times, including start up, shut down and malfunction (SSM). Commenters (4698, 5210) support the proposal for a number of reasons. The commenters state that startup and shutdown periods are normal phases of EGU operation and should not be held separate from other normal operating activities. Reasons stated by commenters (4832, 4834, 4839, 4841, 4984, 5077, 5470) opposing the proposal were varied. One commenter (4714) states that the DC Circuit Court decision regarding emission limits during SSM periods (Sierra Club vs. EPA, DC Circuit Court, 2008) was specifically regarding NESHAP rules and not NSPS rules. EPA has not provided any reasoned explanation or justification for why it is applying the same approach for new, modified, and reconstructed sources in the proposed NSPS rule revisions. Furthermore, EPA has not appropriately evaluated applying the same emission limits for normal operations and for SSM periods. Another commenter (4836) states that coal-fired EGUs co-fire other fuels (typically natural gas or oil) during certain operating modes, such as startup, shutdown, and flame stabilization operations. The proposed NSPS do not address the potential emissions from these co-fired fuels, which will have different emissions profiles from the times the EGU burns coal only. One commenter (4834) states that instead of emission limits, work practices should be proposed for the NSPS to control emissions during SSM periods. Another commenter (4839) states that provisions for SSM periods should follow precedent in the Industrial Boiler MACT Rule. Many of the commenters opposing the proposal state that work practices should be used to control emissions from EGUs during startup and shutdown. For malfunctions, a source should have to address the malfunction as soon as safely practicable. One commenter (17975) states that since maintenance activities are generally carried out for EGU boilers after they have been turned off, the distinction between "maintenance" and "startup/shutdown" is meaningless.

Response: EPA has determined that under the circumstances of this rulemaking it is not appropriate to treat periods of startup and shutdown differently for purpose of complying with the NO_X and SO_2 standards. The NO_X and SO_2 CEMS data used to establish the standards include all periods of operation and thus demonstrate that the standards can be met during periods of startup and shutdown. As a result, it is not necessary to attempt to separate the data and establish separate numerical standards during normal operation and periods of startup and shutdown.

However, for PM it is not practicable to measure emissions during periods of startup and shutdown and we do not have data upon which to base numerical emission limits during periods of startup and shutdown. Therefore, EPA is finalizing work practice standards instead of numeric emission limits for PM during periods of startup and shutdown. These work practices take into account operation of PM control devices. The NSPS requirements will be identical to the NESHAP requirements and are described in Table 3 to Subpart UUUUU of Part 63. See the relevant startup/shutdown sections of the NESHAP portion of the preamble for additional discussion. EPA is committing to reevaluating this approach during the 8-year review when sufficient PM CEMS data is expected to be available from the EGU population

For malfunctions, EPA is finalizing the proposed affirmative defense language for exceedances of the numerical emission limits that are caused by malfunctions. As EPA explained in the preamble to the proposed rule, EPA recognizes that even equipment that is properly designed and maintained can fail and that such failure can cause an exceedance of the relevant emission standard. EPA included an affirmative defense in the final rule in an attempt to balance a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source and appropriately balances competing concerns.

2.1.7 Facility-Wide Emissions Averaging

Comment: One commenter (4839) stated that facility-wide emissions averaging should be allowed as a compliance alternative in certain circumstances. EPA should reconsider and support including facility-wide averaging in emission limitations for existing sources subject to the NSPS as an additional compliance alternative. By including this type of flexibility mechanism, EPA will ensure that facilities will retain some degree of flexibility when complying with the rule requirements. Similarly, varying operational modes or combination of systems (e.g., wet/dry scrubber, ESP or fabric filter) could be employed to provide the greatest potential for economically reducing emissions to meet compliance requirements. EPA's averaging formula should be constructed so that the average emissions by a group of EGUs subject to the NSPS will be no more than what is permitted on an aggregated individual basis. From a practical standpoint, the ability to monitor units with shared stacks may present technical difficulties to the point where separate monitoring is simply not feasible.

Response: While the suggested approach could provide additional flexibility without an increase in emissions to the atmosphere, the present applicability of the NSPS is on a boiler by boiler basis and no change to that approach was proposed. As a result, facility-wide averaging would require a notice and comment rulemaking to at a minimum clearly identify the affected facility, how the averaging would be done, and how modifications and reconstructions would be determined.

2.1.8 Interrelationship of NSPS with other EPA Rulemakings Affecting EGUs

2.1.8.1 Source Category Impact Analysis

Comment: One commenter (4760) states that EPA needs to analyze the combined impacts of all regulatory proposals to the electric industry. Decisions by U.S. electric utilities to add needed electricity generating capacity are being impacted by the breadth and complexity of the numerous rules-- including the NSPS amendments that EPA is implementing to regulate EGU.

Response: The amendments to the NSPS would have a negligible incremental impact on the cost of new coal-fired generation. Annual costs, compared to the existing NSPS requirements, will increase less than 0.3%. In addition, the various regulatory actions impacting air emissions from EGUs require similar controls such that the actual impacts of the NSPS amendments would be even less.

Comment: One commenter (4832) states that EPA proposing substantive changes to 40 CFR 60 subpart Da is outside the scope of the proposed NESHAP rulemaking and the changes have not been properly analyzed or justified. Specifically, EPA is proposing to demonstrate compliance with certain HAP emissions limits under the NESHAP by proxy methods that refer back to SO_2 or PM limits established in 40 CFR 60 subpart Da.

Response: While the proposed SO_2 and PM NSPS amendments are not expected to have any benefits or costs due to the similar benefits and costs in the new source EGU NESHAP requirements, they would be cost effectively achievable in the absence of the NESHAP. Docket entry EPA-HQ-OAR-2011-0044-0002 includes detailed incremental cost effectiveness calculations for each pollutant and EPA has concluded the amended standards are justified in the absence of the NESHAP. If cost and benefits of the proposed amendments were included, it would double count the impacts of the rules.

The NESHAP allows, but does not require, the use of SO_2 and filterable PM as surrogates for acids gases and non mercury metals respectively. Owners/operators that elect to demonstrate compliance with the NESHAP HAP requirements using these surrogates could also concurrently demonstrate compliance with the NSPS standards for those pollutants.

2.1.8.2 Delay of NSPS Rulemaking until NESHAP Affecting EGUs is Finalized

Comment: One commenter (4839) states that the substantial technical comments submitted for the EGU NESHAP warrants a delay of the proposed NSPS to allow EPA sufficient time to consider the more comprehensive affect these revised rules will have on the utility sector. In addition, there are some commonalities in the controls needed to comply with the requirements of the two rules. Syncing the two rules such that they apply to the same set of new sources will allow owners/operators of those sources to better plan for compliance. Finally, since EPA is not under any judicial timeline to promulgate the proposed NSPS, the commenter recommends a delay to account for the considerable time EPA will need to revise the EGU NESHAP and respond to any potential judicial challenges.

Response: While the EGU NSPS amendments and NESHAP were included in the same package and are related in terms of the types of required controls, they are independent rulemakings that both serve the purpose of reducing emissions of pollutants. EPA has sufficiently replied to comments submitted on both proposals. The purpose of the comment referring to syncing the two rules in unclear. For the most part, the comment argues for delaying finalizing the NSPS. The comment referring to syncing the two, however, addresses the issue of which EGU will be subject to the final NSPS standards and the final NESHAP standards for new sources. The universe of EGU subject to both standards was identified on the date the proposed rule was published in the Federal Register. Consequently, new sources are the same for the NESHAP and NSPS and those sources will be subject to both sets of standards. If the commenter's intent is to address the relationship between compliance with the NSPS by reconstructed and modified sources and compliance with the NESHAP by existing sources, compliance with the two sets of requirements cannot be synced.

2.1.8.3 Proposal of EGU NSPS Amendments with EGU NESHAP

Comment: Several commenters (4839, 5087) state that the inclusion of a proposed NSPS rule within the extensive and comprehensive proposed EGU NESHAP is inappropriate and circumvents the appropriate comment period that should be afforded each rule individually. The release of NSPS and EGU NESHAP in the same proposal notice with one 60-day comment period suggests that EPA is rushing its regulatory agenda and short-circuiting the regulatory process. Since EPA is not under a court ordered deadline to develop NSPS amendments, each of these rulemakings should have been proposed separately with their own comment period.

Response: The proposed 60 day comment period was extended an additional 30 days to provide sufficient time for the public to review and comment on both proposals.

2.2 Rule Applicability

2.2.1 Regulation of IGCC facilities under 40 CFR 60 subpart KKKK

Comment: EPA requested comment on whether or not an IGCC EGU that co-produces hydrocarbons or hydrogen should be subject to the combustion turbine NSPS under 40 CFR 60 subpart KKKK instead of the EGU NSPS under 40 CFR 60 subpart Da. Several commenters (4836, 5715) state that an IGCC EGU that coproduces hydrocarbons or hydrogen should be subject to subpart Da. One commenter (4836) states that IGCC EGUs are designed and structured differently than natural gas-fired combined cycle EGUs. For the sake of clarity and regulatory certainty, there should not be a mechanism that would require a particular EGU to switch back and forth between different NSPS standards, even if an IGCC is capable of using natural gas as a fuel. Such units that may co-produce hydrocarbons or hydrogen still convert coal or oil into electricity, and apportioning the parasitic load would be difficult. The commenter requests that EPA provide a heat input-based alternative based on the raw feed stock to the gasifier for these units instead of struggling to make them demonstrate compliance with an output-based standard. Another commenter (5715) states that not applying subpart Da to certain IGCC EGUs that co-produce hydrocarbons or hydrogen is not logical. All IGCC facilities that sell more than one third their potential electric output capacity and more than 25 megawatts of electricity (MWe) to the grid are and should be classified as an EGU subject to 40 CFR 60 subpart Da whether the EGU produces other useful byproducts or not, consistent with the applicability of EGUs to 40 CFR 60 subpart Da that are classified as combined heat and power units.

Response: The IGCC facilities that meet the existing applicability criteria will continue to be regulated under subpart Da. EPA concluded that a gross output based standard, using the revised definition of gross output, is appropriate and can be relatively easily measured for all affected facilities, including IGCC facilities. A heat input based standard would require an IGCC facility owner/operator to measure the coal input to the gasification system and assume all of the energy is input to the stationary combustion turbine and heat recovery steam generator, and calculate a site specific f-factor and employ a stack flow meter and CO_2 CEMS or a fuel flow meter. EPA has concluded that the additional complexity associated with such an approach would not yield improved results compared to an output-based standard.

2.2.2 Exemption of EGUs Using "Innovative Technologies"

Comment: One commenter (5715) states that EPA is not authorized under the CAA to allow the proposed exemption of certain EGUs using "innovative technologies" from complying with the NSPS emissions standards. The CAA only allows EPA to grant a compliance time extension for such affected EGUs on a case-by-case basis that meet certain conditions specified in the statute. Several commenters (4839, 4893, 4984) support the proposed exemption. One commenter (4839) requests that to avoid precluding the development of new technologies, EPA should consider a broader applicability of the exemption to include all DOE-funded commercial-scale technology demonstration projects.

Response: As explained in the proposal preamble, the compliance time extensions under section 111(j) of the Act are not adequate for owners/operators of new EGUs that would be affected facilities subject to subpart Da to secure the funding necessary for construction. As such, the development of promising technologies that offer potential reductions in criteria, hazardous, and GHG emissions could be restricted. The permits will be granted on a case-by-case basis and depend on the anticipated emissions performance of the specific technology. Since nether multi-pollutant controls or pressurized fluidized bed boilers have demonstrated at the size necessary for applicability to subpart Da we cannot do a separate analysis to determine an appropriate emissions rate.

To facilitate development of emerging technologies that offer potential for future emissions reductions, the commercial demonstration permit exemption will be maintained as proposed for pressurized fluidized beds and multi-pollutant control technologies. Neither of these technologies is generally applicable to existing facilities, and overly stringent standards could impede their future development and make financing projects cost prohibitive. The majority of existing facilities already have some form of emissions control technology. Installing a multi-pollutant control technology is not necessary and pressurized fluidized beds are sufficiently different from traditional designs that retrofits are unlikely. However, advanced combustion controls are applicable to existing facilities and the exemption is not necessary to further the development of the technology. That exemption is not included in the final amendments.

DOE-funded technology demonstration projects are typically installed at existing EGUs and would not trigger applicability of the NSPS requirements. Therefore, the exemption would not be applicable. If DOE were to request that EPA evaluate the appropriateness of an exemption for DOE-funded technology demonstrations at some point in the future, such an exemption could be considered in a future rulemaking.

2.2.3 Applicability to Permitted EGUs for which Construction Has Not Commenced

Comment: One commenter (4830) states that EPA must appropriately accommodate permitted facilities for which construction will not have commenced prior to the date of the NSPS regulation. Several electric utility entities have recently obtained air permits authorizing the construction of new units. However, they were not in a position to commence construction on these new units prior to the date that EPA intends to apply the proposed NSPS to facilities that have not commenced construction (May 4, 2011). As a result, these units will be regulated as new sources under this proposed rule. This situation creates significant inequities for the projects that are permitted but have not commenced construction prior to the proposed NSPS, and ultimately, this proposal may prevent the projects from being implemented, depending on the NSPS adopted in the final rule.

Response: Section 111(a) of the CAA defines a new source as one for which construction or modification commences after the publication of proposed regulations applicable to the source. In this case, the relevant date is May 4, 2011 and any source which commences construction or modification after that date is a new source for purposes of the final regulations. EPA has long defined "commenced" in this context to mean "that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification." (40 CFR 60.2). Merely obtaining an air permit authorizing construction does not meet this requirement. EPA disagrees that the NSPS amendments will prevent projects from going forward. While amended NSPS typically require the installation of improved emissions control equipment, the impacts of complying with the amended standards would not ultimately change the investment decisions of the owner/operator of an affected facility. On average, the standards have minimal impact on the capital cost of a new EGU, cost less than $10/kW (less than a 1% increase). Furthermore, the final standards are achievable for a range of technologies and coal types and, therefore, would not require significant redesign of already permitted facilities or impact the decision on the type of boiler used or fuel selection.

2.3 Particulate Matter (PM) Emissions Standards

2.3.1 Selection of BSER for PM Emissions

Comment: Several commenters (4765, 4836, 5089, 5715) state that the proposed NSPS for PM emissions does not reflect the application of the BSER. Commenters differ as to which PM emissions control technologies should be used as BSER for establishing the NSPS emission limits. One commenter states that EPA's proposal to require new facilities to meet the same limits already achieved by many existing sources is contrary to the clear requirements of the statute and Congressional purpose to require new sources to apply the best demonstrated systems of pollution control. Instead, EPA sets PM standards that are "achievable" by all new sources (and even many existing sources) rather than standards that are "achievable" through the application of the best adequately demonstrated system of emissions control, as the CAA requires. One commenter (4765) states that CAA §111(a)(1) does not allow EPA to base an NSPS on a BSER that is a combination of technologies and EPA has not attempted to do so in the past.

Response: The amended PM standard is a filterable only standard. As a result, a fabric filter was identified as BSER. The BSER can take into account multiple factors including, but not limited to, choice of generation technology, fuel selection, and multiple emission control technologies. Nothing in the CAA limits BSER to a single emissions control technology.

2.3.2 Regulation of Combined PM Emissions

Comment: Many comments were received in support of and in opposition to the proposal to establish a new combined PM emissions limit for EGUs that is determined by adding the measured condensable PM plus the measured filterable PM. Commenters' (4698, 4710, 5715, 5210) reasons for supporting the proposal include 1) some state permitting agencies already regulate condensable PM for steam generating; and 2) methods now exist to both measure and control condensable PM. One commenter (4714) notes that the State of Texas has regulated condensable PM through permitting for more than three decades.

Commenters (4712, 4766, 4836, 4989, 5075, 5077, 5089, 5208) oppose the proposal for a number of reasons. Changing the existing NSPS for PM from a filterable PM standard to a combined PM standard by basing the proposed emissions limit on the performance of the top 20% best performing units is unlawful and arbitrary. EPA cannot establish a combined PM emissions limit because the Agency failed to follow the CAA statutory requirements for establishing a standard by not identifying the condensable PM component, how to control condensable PM, or what BSER is for reducing condensable PM emissions. Also, BSER for filterable and condensable PM components are separate. There is no basis for establishing an emissions limit at the emission rate expected by the best performing 20% of the industry, when EPA has not provided any guidance on how the rest of the industry might seek to comply. Commenters also state that the proposed compliance procedures for the combined PM standard are unworkable because EPA Test Method 202 is inadequate to measure the condensable PM component.

Response: EPA Test Method 202 was promulgated in December 2010. The revised test method is as precise and accurate in measuring condensable PM as Method 5 or 17 are at measuring filterable PM. We have concluded it would be possible to establish and determine compliance with a combined PM standard (Method 5 plus Method 202), but based on comments received and on further consideration since the proposal, we have concluded it is appropriate to amend only the filterable PM standard at this time. Post proposal, EPA has become aware of the complex interactions between control equipment configurations and the combined PM emissions rate that make it difficult to set a nationwide standard for combined emissions at this time. In a future rulemaking, we will specifically request comment on the following factors necessary to establish a nationwide standard: i) the appropriate monitoring procedures, ii) whether separate standards for condensable PM and filterable PM have any benefit over a combined PM standard, and; iii) the appropriate numerical standards in each case. To gather a basis for the rule, subpart Da is amended for new facilities to require Method 202 testing and reporting of those emissions each time a Method 5 or 17 performance test is performed. This approach minimizes the burden to the regulated community, while at the same time collecting sufficient data for evaluation of a nationwide standard. If appropriate, EPA will include condensable PM in the PM standard in a future rulemaking that accounts for annual variability. The incremental cost of Method 202 over Method 5 or 17 is less than $700 (10% of PM testing cost).

While EPA plans on evaluating separate filterable and condensable PM standards, we support the present approach that recent permits have taken in establishing a combined PM standard that includes both filterable and condensable PM. Controls required by an NSPS help in achieving and protecting the NAAQS. In the context of a PM standard, the relevant NAAQS is for PM_{10} and $PM_{2.5}$. For this source category, a combined PM measurement represents mostly $PM_{2.5}$ emissions since the filterable controls remove the larger sized PM. The primary distinction between filterable and condensable PM is based on temperature, not the form of the PM in the ambient air. The NSPS establishes standards that can be met through the use of the best controls for managing the ambient air pollutant. With regard to setting an NSPS for PM emissions, we chose to issue a filterable only standard, rather than a combined PM standard, in part because of the difficulties that may exist in quantifying particle size in a wet stack environment and recognition that many new EGU will employ wet scrubbers. Further, while the technology that best controls filterable PM may be different from that which best controls condensable PM, the available data do not establish a distinct line that differentiates the filterable PM and condensable PM across a number of sources. This is demonstrated by the fact that the Part III EGU NESHAP ICR data, indicates that some units with lower combined PM emissions had relatively low filterable PM emissions with somewhat higher condensable PM emissions, while other units had a more balanced control of filterable and condensable PM.

In the proposal, we identified dry sorbent injection (DSI) to neutralize SO_3 to sulfate prior to removal by a mist eliminator or particulate control and a wet ESP as control technologies for condensable PM. However, there are several additional measures that control condensable PM. These include, but are not limited to, (1) the selection of catalysts which minimize the formation of SO_3 from SO_2, (2) minimizing the temperature at which the particulate matter control device operates, (3) minimizing the ammonia slip when SCR or SNCR is used, and (4) a more efficient mist eliminator. In addition, the sulfuric acid mist portion of condensable PM emissions is strongly dependent on the sulfur content of the incoming coal. All of these factors need to be taken into consideration in establishing a meaningful national standard. At this time we do not have sufficient knowledge to determine the combination of control technologies which will achieve the best level of control of both filterable PM and condensable PM across a number of sources and, thus, cannot establish a technical basis for an appropriate national combined PM emissions standard. The additional condensable PM test data will allow us to evaluate the capabilities of a combination of techniques to reduce PM emissions. One potential outcome could be a national PM standard that is based on the sulfur content of the coal, similar to the format for the SO_2 emissions standard. Since we did not propose that approach, we plan on doing a future notice/comment rule that specifically requests comment on the best approach for setting a national standard that achieves the best level of control of both filterable and condensable PM across many sources.

Even though we are not establishing a national PM standard that includes condensable PM, emissions of condensable PM by facilities subject to the amended requirements in subpart Da would not be uncontrolled. All new facilities in this source category would be subject to PSD and be required to account for condensable PM in performing the required analysis under that program. In addition, condensable PM emissions are generally lower for facilities with lower filterable PM emissions and high SO_2 control rates. Since the amended NSPS will require greater control of the emission of these pollutants, there should be some reduction in emissions of condensable PM.

2.3.3 Regulation of $PM_{2.5}$ Emissions

Comment: One commenter (4841) states that a separate filterable $PM_{2.5}$ standard should not be established due to both measurement issues with respect to wet stacks and also because control technologies installed for combined PM, NO_X, and HCl/SO_2 will result in reductions of both direct $PM_{2.5}$ and $PM_{2.5}$ precursors.

Response: Due to monitoring limitations and the commonality of controls for PM_{10} and $PM_{2.5}$, the amendments do not include a separate standard for $PM_{2.5}$.

2.3.4 Selection of PM Emissions Limit Value

Comment: Several commenters (4714, 4765, 4836, 5075) state that the proposed PM emissions limit is not achievable on a nationwide basis, and as a result the final rule needs to be revised upwards to reflect the actual levels of performance achievable. Several commenters (4673, 4836) state that the proposed PM emissions limit is so stringent that it would effectively preclude construction of new coal-fired EGUs. Several commenters (4712, 4989) state that the methodology EPA used to select the proposed PM emissions standard does not sufficiently address variability in EGU fuel use, equipment design, and operation. One commenter (4713) states that PM emission limits for new source EGUs should be the same in the NSPS and NESHAP. One commenter (5210) examined the emissions limits in 27 permits and permit applications for proposed coal-fired EGUs and concludes that a combined PM standard of 0.030 lb/MMBtu best reflects BSER for new EGUs. Moreover, of the 27 permit and permit application limits reviewed, 14 listed both a filterable PM limit and a combined PM limit. The commenter also requests that EPA either adopt the most stringent feasible filterable PM standard for modified EGUs or finalize a combined PM standard that reflects a BSER requiring additional controls for condensable PM for these units.

Response: For the reasons explained previously, EPA is issuing a final standard for filterable PM only. The amended standard is appropriate for a national requirement as it represents BSER for both new and modified facilities and takes variability into account. Data submitted as part of the EGU NESHAP ICR for pulverized coal EGUs burning bituminous and subbituminous coals and fluidized bed EGUs burning lignite, petroleum coke, and bituminous coal with multiple performance tests show that the amended PM standard is demonstrated and achievable. The data also show that an ESP can be used with coals with ash contents of up to 9 lb/MMBtu to achieve the standard. Data for EGUs that only reported a single performance test as part of the EGU NESHAP ICR, demonstrate that the amended standard is achievable by EGUs equipped with an ESP when using coals with ash contents of up to 14 lb/MMBtu. That data also demonstrate that the amended standard is achievable by EGUs equipped with a fabric filter when using coals with ash contents of up to 68 lb/MMBtu. Further, the amended new source standard of 0.090 lb/MWh, which is consistent with the EGU NESHAP standard, accommodates IGCC facilities in multiple operating modes. We are not changing the PM standard for modified facilities finalized in 2006 because modified facilities would have to increase the size of any existing ESP or retrofit a fabric filer beyond what the present standard requires to meet the amended new source standard and some existing facilities would be unable to do this because of space constraints.

Commenter 5210 misinterpreted the proposed combined PM standard of 0.055 lb/MWh as being 0.055 lb/MMBtu. The proposed standard is actually an order of magnitude more stringent than the comment suggests. In addition, if we were establishing a combined PM standard, which we are not, it does not appear that the suggested standard of 0.030 lb/MMBtu (~0.30 lb/MWh) combined PM would reflect BSER for combined PM. Since the amended filterable PM standard is 0.090 lb/MWh, the suggested standard would result in an approximate allowable condensable PM emissions rate of 0.21 lb/MWh (the resultant combined standard would be 0.30 lb/MWh). 206 of the 272 condensable PM data points in the EGU NESHAP ICR are below this value, indicating that a more stringent standard would be indicative of the BSER.

Comment: One commenter (5279) states that the proposed PM emissions limit should be revised to address the use of duct burners at IGCC facilities when fired using syngas and using natural gas. The commenter states that higher PM emission limits than the proposed limit are required when operating under either of these two scenarios.

Response: The PM standard is based on the permit conditions for an IGCC and accounts for both operating conditions.

2.3.5 PM Control Cost Analysis

Comment: Many commenters (4635, 4656, 4765, 4766, 4686, 4830, 4836, 5075, 5089, 5240) state that EPA failed to independently calculate the control costs for implementing the proposed PM emissions limit as required by the CAA § 111(a)(1). It specifies that EPA "tak[e] into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements..." when establishing NSPS. Instead, EPA has unlawfully relied on the PM emissions reductions that it anticipates to occur through implementation of the proposed NESHAP for EGUs. EPA concludes that the proposed NSPS PM emissions standard will not result any costs or benefits attributable to implementing the NSPS.

Response: Docket item EPA-HQ-OAR-2011-0044-0002 includes an independent incremental cost analysis and a secondary environmental impacts analysis for the proposed NSPS PM emissions standard. EPA concluded that these costs and benefits would support the amended NSPS in the absence of the NESHAP.

2.3.6 PM Standards Exemptions

2.3.6.1 Opacity Standard Exemption for EGUs Using PM CEMS

Comment: Several commenters (4673, 4766, 4836) state that EPA should exempt EGUs subject to 40 CFR 60 subpart D and using PM CEMS from the opacity standard requirements. For affected EGUs that monitor PM emissions directly with a method EPA has determined as "sufficiently accurate," the surrogate opacity standard is no longer necessary to assure compliance with the applicable PM emissions limit. EPA should finalize the exemption proposed in 2008 for any EGU subject to 40 CFR 60 subpart D that demonstrates continuous compliance with the applicable PM emissions limit on a 24-hour (not 3-hour) average basis.

Response: We agree with the commenters that using PM CEMS provides not only a continuous check on the ability of the PM control device to minimize filterable PM emissions but also a direct, continuous measure of compliance with the filterable PM emissions standard. However, PM and opacity are separate standards. Should source owners/operators want a different averaging time under subpart D, they can petition the Administrator in accordance with the requirements in 40 CFR 60.42(c). Furthermore, the EGU NESHAP includes an existing source filterable PM standard of 0.030 lb/MMBtu as an alternate to measuring total metals. Therefore, the vast majority of subpart D facilities will be installing controls that would allow them to control PM emissions to such an extent that the opacity standard would no longer be applicable.

2.3.6.2 Opacity Standard Exemption for EGUs Complying with a Combined PM Standard

Comment: One commenter (4836) supports EPA's proposed opacity standard exemption for affected EGUs complying with a combined PM emissions limit.

Response: The final rule amendments do not include a combined PM emissions limit (see Section 2.3.3) and, therefore, the proposed exemption is no longer relevant.

2.3.6.3 PM and Opacity Standard Exemptions for Natural Gas Fired EGUs

Comment: Several commenters (4836, 4841, 17711, 17852) support EPA's proposed opacity standard exemption for natural gas fired EGUs. However, one commenter (4836) does not understand why EPA proposes to limit the Subpart D exemption to those facilities subject to a federally enforceable permit limiting fuel use. No such condition is attached to the proposed Subpart Da exemption. The commenter also does not understand why EPA has not proposed to exempt Subpart Da facilities that combust only natural gas from the filterable PM standards. Those facilities also will have negligible filterable emissions. As long as the facility is actually combusting only natural gas, it should be exempt from filterable PM and opacity standards regardless of a pre-existing permit restriction.

Response: The "federally enforceable permit" requirement has been removed from subpart D so that the exemption applies to facilities that elect to switch to natural gas, but that maintain the ability to burn other fuels without a permit modification in the future. The opacity standard would be effective immediately if the facility switches back to other fuels. The second part of the comment is unclear since the proposed language in paragraphs §60.42Da(a)(4), (e), and (g) exempt natural gas-fired EGUs from the PM standard.

Comment: One commenter (5749) states that EPA should clarify the circumstances under which 40 CFR 60 subpart Da may apply to gaseous fuel firing, where such gaseous fuel is not a fossil fuel (for example, where a non fossil gaseous fuel is combusted in combination and/or alternately with a fossil fuel). To the extent that Subpart Da would apply under any such circumstance, EPA should extend the Subpart Da exemption from PM and opacity limits for natural gas units to also apply to gaseous fuel fired units, such as those firing landfill gas. The commenter believes that landfill gas and other non fossil gaseous fuels have emission profiles similar to those of natural gas, and should be encouraged as viable alternatives to fossil fuels, including natural gas.

Response: A facility that only burns non fossil gaseous fuels would not be subject to subpart Da even if it met the applicability criteria of being capable of combusting more than 250 MMBtu/h of fossil fuel and supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Owners/operators of units that are capable of combusting more than 250 MMBtu/h of fossil fuel that co-fire non fossil fuels would, however, be subject to subpart Da. We have concluded it is not appropriate to provide an outright exemption for all co-fired gaseous fuels since they can potentially contain contaminants that result in PM emissions and opacity. However, the amount of sulfur in a gaseous fuel is a general indication of the amount of impurities. Therefore, gaseous and liquid fuels with potential SO_2 emissions rates of less than 0.060 lb/MMBtu are included in the PM exemption, but not the opacity exemption. Other gaseous fuels do not necessarily burn as completely as natural gas. Subpart Da already includes reduced opacity monitoring for owners/operators burning gaseous fuels other than natural gas.

2.3.6.4 PM and Opacity Standards Exemption for Low-Sulfur Fuel Fired EGUs

Comment: One commenter (4836) supports EPA's proposal to exempt EGUs that combust only gaseous or liquid fossil fuel with potential SO_2 emission rates of 0.060 lb/MMBtu or less from the otherwise applicable filterable PM standard, provided the EGU does not use post-combustion SO_2 or NO_X controls. One commenter does not support this option for other forms of oil, especially for No. 4 oil and other grades. Another commenter (4698) opposes the exemption because opacity emissions from EGU firing such fuels is not generally due to fuel ash and impurities but rather is more a function of incomplete fuel combustion.

Response: EPA agrees that opacity and filterable PM emissions from low sulfur oil-fired boilers are a result of incomplete combustion and do not result from fuel ash or impurities. However, EPA believes that 20% opacity would rarely occur at facilities burning these fuels. Therefore, subparts D, Da, and Db are amended to include a provision providing state permitting authorities the flexibility to approve site-specific monitoring requirements for distillate oil containing less than 500 ppm sulfur, while still maintaining the opacity standard itself. This flexibility will be especially beneficial to owners/operators who only burn distillate oil as a backup fuel. The state would then have the flexibility to approve a site specific plan, or (?) require the use of the opacity monitoring procedure set forth in the rule, or the owner/operator could monitor carbon monoxide emissions.

2.4 Sulfur Dioxide (SO_2) Emissions Standards

2.4.1 Selection of BSER for SO_2 Emissions

Comment: Many commenters (4712, 4715, 4765, 4836, 5715, 4989) state that EPA failed to state the BSER that the Agency selected as the basis for establishing the proposed SO_2 emissions standards. One commenter (5715) states that the proposed SO_2 emissions rates are not the result of an analysis of the application or performance of the BSER for SO_2 emissions – instead they are based on the SO_2 emissions rates that are already being achieved by existing EGUs. EPA's BSER determination analysis was not based on the application of new and innovative multi-pollutant control options nor the application of systems of emissions reductions that allow control of greenhouse gas emissions (which EPA is regulating under a separate rulemaking) along with control of SO_2.

Response: The BSER for SO_2 is the same as in the 2006 final amendments, low sulfur coal and a spray dryer or high sulfur coal and a wet scrubber. In this remand, the achievable standards were reevaluated, but no new technology developments have taken place so the BSER technologies were not changed. The facilities used to establish the numerical standard used low sulfur coal and a spray dryer, and the facilities used to establish the percent reduction requirement burned high sulfur coal and used a wet scrubber. EPA has concluded it is not appropriate to base the amended SO_2 standard on potential GHG requirements that have not been proposed.

2.4.2 Selection of SO_2 Emissions Limit Value

Comment: Many commenters (4715, 4765, 4768, 4836, 5715, 4989, 5075, 5077) state that the proposed NSPS SO_2 emissions limit does not reflect the application of the BSER, and that the methodology EPA used to select the proposed SO_2 emissions limit value does not sufficiently address variability in EGU fuel use, equipment design, and operation. One commenter (4836) included an analysis of the data set used by the Agency in evaluating the achievability of the proposed SO_2 emissions limit using the BSER. Based on this analysis, the commenter states that an appropriate SO_2 emissions limit is 1.25 lb/MWh for new units with an optional reduction limit of 96%. In contrast, another commenter (4715) states that EPA did not set the NSPS SO_2 emissions limit based on the best demonstrated unit in its data set. According to the commenter, nearly all of EPA's sample units (12 of 15 units) could meet the proposed NSPS of a 97% reduction in SO_2, and a third of the units (5 of 15 units) could meet a 98% reduction. Furthermore, all of the units in the data set that tested in the 97% reduction range, excepting one, tested in the upper limits of the 97% range. This fact indicates that a 98% reduction limit is achievable. EPA should incentivize the most efficient use of control technologies to achieve the maximum amount of SO_2 reduction. The reduction limit for SO_2 should be set at 98% for this NSPS. One commenter (5210) examined emissions limits of six existing coal units (at Intermountain Power, Colstrip, and Navajo) and the emissions limits in 29 permits and permit applications. Based on those data, the commenter recommends setting a SO_2 standard of at least 0.7 lb/MWh to reflect BSER for all EGUs.

Response: Emissions data for both fluidized bed and pulverized coal EGUs demonstrate that a 97% reduction in potential SO_2 emissions is achievable. While short term data indicates that greater than 97% reduction may at times be achievable, that level of reduction has not been demonstrated to be achievable on a long term basis. Furthermore, even a 97% reduction in potential emissions has only been demonstrated to be achievable for coals with nominal uncontrolled SO_2 emissions of greater than approximately 3.5 lb/MMBtu. Assuming a gross efficiency of 36%, this correlates to a numerical emissions rate of 1.0 lb/MWh. Setting a numerical standard below 1.0 lb/MWh, which would be the result of requiring a emissions reduction of more than 75%, could limit the ability to use medium sulfur coals in new EGUs and drive the market toward subbituminous and low-sulfur bituminous coals.

While subbituminous coal and low-sulfur bituminous coal have inherently low sulfur content and thus low SO_2 emission rates, neither is a viable option for establishing a national standard as the use of these ranks of coal is not practicable for some facilities due to transportation constraints, costs, and supply limitations. The transportation logistics and costs render the use of subbituminous coal by all new coal-fired generation unfeasible. Subbituminous coal is mined in the western states and requires long distance transportation, resulting in increased emissions from locomotives, increased energy consumption, and potential additional rail line construction due to existing rail system limitations. The use of lower sulfur eastern bituminous coal is also problematic as it is in high demand across the eastern United States and abroad. The increased demand does not just come from the electric generation sector, the coal is also in demand for use as a raw material in manufacturing. In addition, available veins of low-sulfur eastern bituminous coals are being exhausted. In addition, adding a subbituminous-fired boiler at an existing site designed to burn bituminous coal would require significant design changes to the coal material handling equipment and other existing ancillary equipment.

Comment: One commenter (17622) states that Table 17- SO_2 Emissions Performance Data in the proposal notice (76 FR 25065) used by EPA to select the SO_2 performance level for EGUs lists the best performing units in terms of percentage SO_2 control and the subsequent commentary incorrectly indicates that with the exception of the HL Spurlock Units 3 and 4, all utilize wet limestone scrubbing technology. The three units at the Harrison Station utilize wet magnesium on demand lime scrubbing technology, not wet limestone technology.

Response: The Harrison technology description has been corrected.

2.3.3 SO_2 Control Cost Analysis

Comment: Many commenters (4635, 4656, 4765, 4766, 4686, 4830, 4836, 4989, 5075, 5240) state that EPA failed to independently calculate the control costs for implementing the proposed SO_2 emissions limit as required by CAA §111(a)(1). It specifies that EPA, "tak[e] into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements…" when establishing NSPS. Instead, EPA has unlawfully relied on the SO_2 emissions reductions that the Agency anticipates from implementation of the proposed NESHAP for EGUs. EPA concludes that the proposed NSPS SO_2 emissions limit will not result any costs or benefits attributable to implementing the NSPS.

Response: In proposal docket item EPA-HQ-OAR-2011-0044-0002 an incremental cost analysis and a secondary environmental impacts analysis include control costs for implementing the proposed SO_2 emissions limit. On the basis of that information, EPA concludes the SO_2 limits are achievable and cost effective independent of the NESHAP.

2.4.4 Coal Refuse-Fired EGU Exemption from SO_2 Standards

Comment: One commenter (5715) states that EPA's proposal to exempt EGUs burning more than 75% coal-refuse on an annual basis from the proposed NSPS for SO_2 emissions and instead allow such units to meet the existing NSPS for SO_2 emissions is unlawful. The commenter states that in proposing to establish such an exemption, EPA failed to distinguish these EGUs as a subcategory warranting separate emissions standards in accordance with the proper statutory requirements as provided by 42 U.S.C. §7411(b)(2) ("the Administrator may distinguish among classes, types and sizes within categories of new sources for the purpose of [setting NSPS]. One commenter (5210) states that new coal refuse-fired EGUs can meet the same standard as other EGUs. The commenter recommends that EPA adopt a SO_2 standard of 0.07 lb/MWh output for units burning 75% or more coal refuse.

Response: Coal refuse-fired EGU is a subcategory for the purposes of the SO_2 standard under the existing NSPS. We neither proposed to eliminate the subcategory, nor in any other way reopened the issue of whether the subcategory is appropriate.

Coal refuse-fired EGU is not a subcategory for other pollutants. The Northeastern 31 EGU is the best performing coal-refuse-fired EGU in terms of NO_X. The facility has demonstrated a NO_X emissions rate of 0.85 lb/MWh and we are therefore amending the standard accordingly. Furthermore, the previous 8 PM performance tests at the Northampton NGC01 coal refuse-fired EGU have been under the amended PM standard of 0.090 lb/MWh.

2.5 Nitrogen Oxides (NO_X) Emissions Standards

2.5.1 Selection of BSER for NO_X Emissions

Comment: One commenter (5715) states that the proposed NSPS to control NO_X emissions (a combined NO_X/CO standards and an alternative NO_X standard) does not reflect the application of BSER. EPA's selection of selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) with advanced combustion controls does not represent BSER for control of NO_X emissions. Furthermore, EPA failed to state the BSER that the Agency selected for controlling CO emissions. The commenter states that EPA's BSER analysis did not evaluate the NO_X and CO emissions reductions achievable by all available NO_X and multipollutant control technologies.

Response: The available data does not demonstrate that SCR can be applied to fluidized bed boilers in all circumstances. As a result, EPA believes that SNCR in combination with good combustion controls achieve the lowest NO_X emissions rate, and are, therefore, considered BSER for such boilers. While it may be possible to apply regenerative SCR to fluidized bed boilers, it is a relatively new technology and emissions rates are not yet available. For pulverized coal boilers, BSER was determined to be the use of advanced combustion controls and SCR. The only currently viable CO controls on EGUs are combustion controls as thermal oxidation and catalytic reduction have not been demonstrated on EGUs.

2.5.2 Combined NO_X + CO Emissions Limit

Comment: Many commenters (4673, 4712, 4836, 4989) object to establishing a mandatory NO_X + CO NSPS emissions limit for EGUs at this time because of limited CO emissions data and the inadequate methodology used to determine the emissions limit. An analyses prepared by one commenter concludes that such a standard is unachievable for many EGUs much of the time. However, several of these commenters (4673, 4836, 4839, 5470) also state that a combined NO_X and CO emissions limit could provide an advantage in terms of compliance flexibility. These commenters do not object to establishing an NO_X + CO emission limit that EGU owners/operators could chose to comply with as an alternative to a NO_X emissions limit. Other commenters (4715, 5715) support EPA establishing a mandatory NO_X + CO NSPS emissions limit for EGUs. However, one commenter states that EPA failed to explain why the Agency believes that a NO_X + CO emissions limit of 1.2 lb/MWh for new sources reflects application of the BSER, when it is at a significantly higher emissions rate than its NO_X-only emissions limit proposed alternative. The commenter concludes that the NSPS emissions limit for NO_X + CO should be lowered to reflect BSER, or at the very least, EPA must select a standard at the low end of the proposed range. Another commenter (17620) states that setting a sufficiently stringent CO standard that avoids poor combustion would be a better option than adopting a combined limit for NO_X + CO. Allowing inappropriately high CO levels by establishing a combined standard will simply permit sources to use less effective SCR controls and emit higher levels of organic HAPs than would limits that are based on the level of NO_X reduction and CO levels achievable by high efficiency SCRs controls.

Response: While EPA believes that the limited data available supports the achievability of a combined NOx/CO standard in at least some circumstance, it does not support the imposition of such a standard across the board. As a result, the combined NO_X/CO standard will be provided as an alternative to the amended NO_X standard. The alternative standard will be 1.1 lb/MWh, as that is the lowest standard that has been demonstrated as achievable for both pulverized coal and fluidized bed technologies. This combined standard is much more stringent than recent separate NO_X and CO limits in BACT permits. The majority of BACT-based CO standards are 0.10 lb/MMBtu or greater. This translates to an approximate CO emissions rate of 1.0 lb/MWh. With corresponding BACT-based NO_X standards of 0.70 lb/MWh, this corresponds to an equivalent combined standard of 1.7 lb/MWh. The combined standards for coal refuse-fired and modified EGUs were determined by adding a CO factor, 0.4 lb/MWh, to the NO_X standard. This is the best CO emissions rate that has been demonstrated for both fluidized bed and pulverized coal boilers.

Comment: One commenter (5210) states that EPA must set the most protective NO_X standard. While supporting EPA's suggested benefits of a combined NO_X + CO standard, the commenter states concern over if and how the Agency weighed the different health and environmental impacts of NO_X and CO in determining the proposed combined standard. It appears the Agency weighed them equally, which the commenter believes is not appropriate, given the greater health and environmental impacts of NO_X and its contribution to ozone. While the commenter does not want CO emissions to significantly increase as a result of NO_X controls, the commenter is concerned that the flexibilities of a combined NO_X + CO standard will provide for an ultimately more lenient NO_X standard, resulting in fewer reductions. Therefore, the commenter recommends that EPA at the least set the most stringent standard feasible for NO_X, in order to protect public health and the environment from the harmful impacts of ozone, PM, and other NO_X related emissions. Another commenter (5208) states that a combined NO_X + CO standard potentially would allow higher NO_X emissions that would not protect the more stringent nitrogen dioxide (NO_2) National Ambient Air Quality Standard (NAAQS).

Response: The combined standard is based on the best performing facilities. New facilities would, at a minimum, have to reduce emissions to below the existing subpart Da NO_x standard established in 2006 to comply with the standard. Therefore, it is a tightening and not a relaxation of the existing requirements and would not result in increased NO_X emissions.

Other federal and state permitting programs are designed to take into account the specific health and environmental issues. In regions where reductions in NO_X emissions would result in more significant health and environmental benefits the permit could require the maximum reductions in NO_X. However, as described in the preamble this could lead to significant increases in CO emissions such that the combined standard would not be achievable.

2.5.3 NO_X Emissions Limit

Comment: Several commenters (4712, 4765, 4768, 4836, 5075) state that the proposed NO_X emissions limit is not achievable on a nationwide basis, and the final rule should, therefore, be revised upwards to reflect the actual levels of performance achievable. In addition, a separate NO_X emissions limit should be set for modified EGUs subject to the NSPS. Several commenters (4712, 4768) state that the methodology EPA used to select the proposed NO_X emissions limit value does not sufficiently address variability in EGU fuel use, equipment design, and operation. One commenter (4768) includes their analysis of the data on which EPA based its determination that the proposed NO_X emissions limit is achievable using BSER. Based on this analysis, the commenter asserts that an appropriate NO_X emissions limit is 0.83 lb/MWh for new units and 1.1 lb/MWh for modified or reconstructed units. The commenter states that the NO_X emissions standard for modified units should be based on the performance of cell burners, wet-bottom boilers, and cyclone fired EGUs. The commenter further notes that recent consent decrees for SCR-equipped cyclone boilers require NO_X emissions between 0.100 to 0.120 lb/MMBtu.

Response: The available data demonstrates that the proposed standard of 0.70 lb/MWh is achievable by both new and retrofit pulverized coal and fluidized bed boilers burning various coal types. This is true for modified units as well as new and reconstructed units; however, in recognition of the difficulties of retrofitting certain modified facilities with advanced combustion controls, the final NO_X standard for modified facilities is 1.1 lb/MWh. Since the CEMS data used in establishing the standards included long term data, various operating conditions and variability are inherently accounted for. I The comment about cell burners and wet-bottom boilers is unclear. The Cardinal 1, 2, and 3, Muskingum River 5, and Belews Creek 1 EGUs are cell burners retrofit with SCR and have demonstrated emission rates below 0.70 lb/MWh. In addition, the Dallman 4 EGU is a wet-bottom boiler with SCR operating below 0.70 lb/MWh. Cyclone boilers are the only EGU design that has not been demonstrated to be able to achieve the proposed standard. Subbituminous cyclone-fired EGUs (Coffeen, Baldwin, and Allen S. King) have demonstrated NO_X emission rates of less than 0.95 lb/MWh are achievable. However, no bituminous or lignite-fired cyclone EGUs have achieved comparable emission rates. The best performing bituminous and lignite-fired cyclone EGUs without SCR are the Merrimack and Leland Olds facilities. These EGUs have demonstrated that cyclone EGUs can maintain NO_X emission rates to less than 4.0 lb/MWh. The addition of 75% efficient SCR (or a multi-pollutant control technology) to these facilities would reduce NO_X emissions to less than 1.1 lb/MWh.

The differences in the calculated 30-day emission rates between the commenter and the EPA is attributed to the procedure used to calculate the 30-day averages. The EPA 30-day averages are calculated using the procedures described in the proposal (sum of emissions of the applicable pollutant divided by the sum of the gross output), while the commenter used the average of the hourly emission rates for the 30-day period. As stated in the proposal, the EPA procedure results in lower numerical emission rates because hours with high emission rates but low heat inputs (typical of startup, shutdown, and low load operation) are not weighted as heavily.

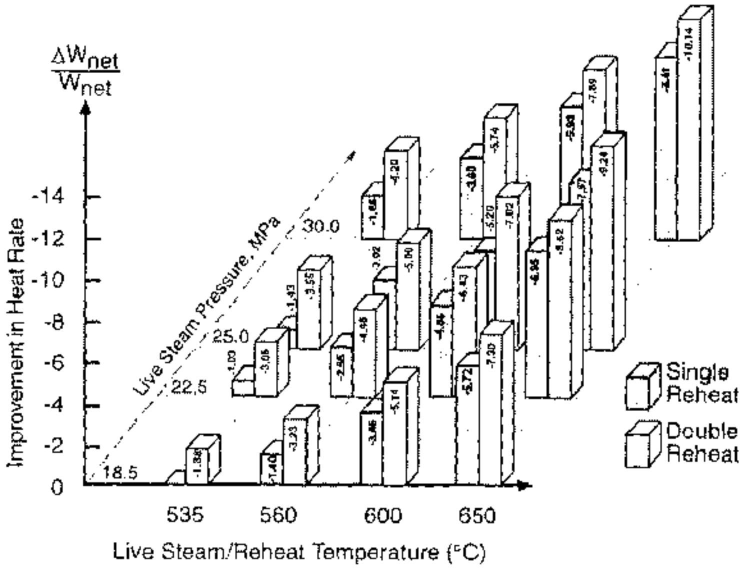
Comment: One commenter (5077) states that emissions during startup and shutdown periods have a particularly large impact on NO_X emissions, even after taking into account the compensating effect of a 30-day rolling average. Hence, these periods need to be excluded in the evaluation of compliance with the standard. Further, EPA should set a higher NO_X NSPS standard for modified units, since older modified units typically have higher heat rates than new units.

Response: The CEMS data used to establish the standards includes emissions during startup and shutdown, so there is no reason to separately evaluate those periods. The standard accounts for emissions typically being higher during periods of startup and shutdown and at the same time is sufficiently stringent to require owners/operators to minimize emissions during all periods of operation to comply with the 30-day standard. The final standard for modified units (1.1 lb/MWh) is based on CEMS data from facilities using subcritical steam conditions and accounts for the higher heat rates of older facilities.

Comment: One commenter (4830) states that the proposed NO_X NSPS of 0.70 lb/MWh appears to eliminate the further use of lignite coal for new EGUs. Section 111(a) requires EPA to explain the economic and energy impacts when establishing NSPS. Lignite coal is an abundant resource in the upper mid-west and Gulf Coast areas and elimination of it as an energy source would have significant regional economic impacts. EPA has the discretionary authority to subcategorize EGUs such that lignite-fired EGUs could have different NO_X standards based on BSER for lignite. Thus, EPA should subcategorize the lignite NO_X NSPS for new units. In addition, EPA has not demonstrated that non-lignite-fired units can meet the preferred 0.70 lb/MWh considering the inclusion of startup and shutdown periods into the compliance period. Accordingly, the alternative standard of 0.80 lb/MWh is more representative of what can be realistically achieved for non-lignite units, and no level lower than that should be considered for the NO_X NSPS for new units.

Response: While the lignite-fired Oak Grove pulverized coal facilities use supercritical steam conditions (3,535 psi and 1,010 °F), increasing the steam temperature and pressure to those used at the Weston 4 facility (3,775 psi and 1,085 °F) would reduce fuel use and emission rates by approximately 2.5%. The figure below shows the impact of various steam conditions on the relative heat rate of an EGU. In addition, upgrading the heating value of the lignite from 6,800 Btu/lb to 10,000 Btu/lb would improve the efficiency of the EGU by almost 4%. Designing either of these things into a new lignite-fired EGU using the same control configuration as Oak Grove 1 would theoretically reduce the NO_X emissions rate to less than the 0.70 lb/MWh amended NO_X standard. The permit for Oak Grove requires an NO_X emissions rate of 0.080 lb/MMBtu. Using the same control configuration, a gross efficiency of 39% would be required to comply with the amended NO_X emissions rate. This level of efficiency has been widely demonstrated for supercritical boilers burning subbituminous coals. A facility burning upgraded lignite would be expected to similar efficiencies as a subbitumous-fired EGU.

The Sandow 5B facility is a subcritical (2,420 psi and 1,005 °F) lignite-fired fluidized bed EGU and is presently operating below the combined NO_X/CO standard. Furthermore, increasing the steam temperature and pressure to those used at the Weston 4 facility would reduce fuel use and emission rates by approximately 5%. In addition, upgrading the heating value of the lignite from 6,300 Btu/lb to 10,000 Btu/lb would improve the efficiency of the EGU by almost 5%. Implementing both of these for a newly designed EGU using the same control configuration as Sandow 5B would theoretically reduce the NO_X emissions rate to below the 0.70 lb/MWh amended NO_X standard. Fluidized bed boilers are not limited in application since they are available in various sizes, the largest individual unit is 460 MW, and are able to utilize supercritical steam conditions.



As described elsewhere in the response to comments, the 0.70 lb NO_X/MWh is achievable for all of the primary coal (and petroleum coke)-fired EGUs.

2.6 Compliance Requirements

2.6.1 Opacity Monitoring

Comment: Many commenters (4712, 4836, 4989) support EPA's proposal to allow affected EGUs using a PM continuous monitoring system (CEMS), a fabric filter bag leak detection system (BLDS), or an electrostatic precipitator (ESP) predictive model to be exempted from the existing requirement to install a continuous opacity monitoring system (COMS).

Response: The final rule amendments include a provision allowing affected EGUs using a PM CEMS, a fabric filter BLDS, or an electrostatic precipitator (ESP) predictive model to be exempted from installing a COMS.

Comment: Several commenters (4673, 4836) support EPA's proposal to reduce the frequency of visible emissions testing for affected EGUs that are subject to an opacity standard, but are not required to use a COMS. The commenters further note that when EGUs are subject to state air permit requirements to conduct Method 9 visible opacity tests, visible emissions testing requirements under the NSPS are redundant and may conflict with the state requirements. The commenter recommends that EPA add a provision in the rule explicitly allowing permitting authorities the discretion to waive any NSPS visible emissions testing as long as the state testing is at least as frequent.

Response: All the boiler rules have been amended to allow the permitting authority the discretion to establish site-specific monitoring plans for owners/operators of facilities burning fuels that typically result in low opacity. The frequency of Method 9 performance testing for owners/operators of facilities with some visible emissions, but with all 6-minute readings of less than 5%, has been reduced from every 6 months to every 12 months. The frequency of opacity monitoring for owners/operators of facilities with higher opacity is unchanged. The additional testing frequency for facilities with opacities of 5% and higher is necessary to adequately assure compliance with the opacity standard.

2.6.2 PM Continuous Emission Monitoring

Comment: Several commenters (4989, 5077) oppose removal of the option to use Method 19 of Appendix A when the PM CEMS minimum data availability conditions are not met. One commenter (5077) states that removal of the option to use Method 19 of Appendix A eliminates a credible option to provide data when monitor availability falls below a required threshold. Without the Method 19 option, a source that does not meet the data availability requirements would have to obtain data using "other monitoring systems." EPA provides no reason in the proposed rule for removing the Method 19 option.

Response: The redline included the intended edits and the amendatory language was in error. The option to use Method 19 has not been removed in the final rule.

Comment: Several commenters (4989, 5077) stated concerns about the ability of PM CEMS to meet the proposed 90% availability requirement on a 30-day rolling average basis because of the limited number of installations of PM CEMS on EGUs. One commenter (5077) requests that EPA consider using a 75% data availability requirement when validating a required reporting duration (i.e., 30 day rolling average).

Response: We find the commenter's concern about a limited number of PM CEMS installations on utility units to be misplaced, as over 100 EGUs have installed and are operating PM CEMS. As we are unaware of situations that have caused or may cause data availability from these units with PM CEMS to be below ninety percent, we find that that level is achievable in the field and that there is no need to lower it.

Comment: One commenter (4989) states that for the PM CEMS missing data procedures EPA is proposing to replace references to "valid" data with the phrase "non-out-of-control" data. Neither of these terms are defined in Subpart Da.

Response: The part 63 definition for "out-of-control" has been added to subpart Da. This amendment improves consistency for reporting and reduces burden to the regulated community.

2.6.3 Electronic Reporting of Performance Test Data

Comment: Several commenters (4712, 4836, 4989, 5077) opposes EPA's proposal specifying mandatory electronic reporting of PM CEMS performance data and Relative Accuracy Test Audit (RATA) data to EPA's Central Reporting Data Exchange (CDX) using the Electronic Reporting tool (ERT). The commenters state that this proposed requirement is unlawful, unsupported, and incomprehensible for the following reasons: 1) EPA has not articulated the purpose of the submission and reconciled that with existing reporting requirements, 2) EPA has not used appropriate terms to identify the data required to be submitted, 3) EPA has not submitted an Information Collection Request (ICR) and obtained Office of Management and Budget(OMB) approval as required by the Paperwork Reduction Act (PRA) for the data to be reported, and (4) EPA has not provided a reporting format compliant with EPA's Cross-Media Electronic Reporting Regulation (CROMERR) requirements.

Response: EPA strongly disagrees with the statement that the submittal of performance data using the ERT is unlawful, unsupported, and incomprehensible. Section 114 of the Clean Air Act specifically allows EPA to require the submittal of emissions (and other environmental data) to develop regulations. In fact, in support of this rulemaking, there was an information collection request (ICR) that affected many facilities. If EPA had had these performance data prior to the rulemaking, then an extensive ICR would not have been needed. We believe that requiring that such data be routinely submitted using the ERT will eliminate, or at least reduce, the need for such an extensive ICR in conjunction with future rulemaking. In answer to item 1 above, the purpose of requiring the submission of the results of performance tests is to support the development of regulations. In addition, performance test data will be used to improve emissions factors, develop control strategies, determine rule effectiveness, and support other air pollution control activities. Assuming the commenters meant performance test reports, rather than performance data, EPA disagrees with the statement that the requirements to submit performance test reports to EPA using the ERT are unsupported. EPA has already required the use of the ERT for several information collection requests and has promulgated several other rules that require its use. Further, EPA as a whole has been working toward electronic submittal of environmental data and information for some time; see, for example, the Risk Management Plan information required in 40 CFR part 68 and the Toxics Release Inventory requirements in the Emergency Planning and Community Right-to-Know Act of 1986. Electronic reporting allows for easier submission and storage of data and will provide stakeholders easier access to the information, thereby facilitating easier review of that information. If the commenters meant the submittal of the PM CEMS data, EPA also disagrees with the commenters on that point. EPA has concluded that the data are important in determining whether a facility is being properly operated. The data are also important for determining compliance with this regulation. Thus, EPA is establishing a system to more readily facilitate the collection and analysis of the data.

EPA is not sure what the commenters intend in stating that the requirements are incomprehensible. The electronic reporting requirement is clear on its face and, for the reasons stated above, electronic reporting of data is a very good solution, both for EPA and for industry, for the collection and review of air quality data. If the incomprehensible comment pertains to the ERT, our response is that the ERT has been used by many source testing companies and is steadily improving. EPA has worked very closely with the source samplers and industry to identify and correct problems encountered with its use. In response to item 2, EPA is not sure what the commenters are asking. EPA developed the ERT using/in collaboration with former source testing personnel and in conjunction with source testing companies. The model for the ERT was and is the performance test requirements in the parts 60 and 61 general provisions. The input of source testing companies was integral to the development of this tool and we are continuing to work closely with source samplers. Thus, common source testing terms are used in the ERT and most of the users of this tool have had little trouble in understanding what is required. The response to item 3 is that EPA will be accounting for ERT use in the ICR for the final regulation. EPA has concluded that requiring the use of this tool will not significantly increase any costs in the reporting of performance test data and will probably eventually result in a reduction in costs. Many source testing companies and most major facilities already use their own systems to gather performance test data electronically. EPA believes that the ERT works well and is ready for general use. EPA also disagrees with the statement in item 4. EPA is working closely with the Office of Environmental Information to establish the procedures necessary to ensure that ERT submittals through EPA's Central Data Exchange are compliant with the Cross-Media Electronic Reporting Regulation. EPA will have this process completed prior to the time when the ERT submittals are required.

Comment: One commenter (4674), a state air regulatory agency, intends to continue to request affected owner or operators to submit hard copies of stack test reports to the State, in addition to EPA's collection of stack testing data via the Electronic Reporting Tool (ERT), and therefore supports EPA's preservation of related requirements in 40 CFR 60.8 and 60.11. The commenter believes that the stack test data reported must be considered along with additional, specific information for each source's operations. This evaluation cannot be easily conducted with the limited data reported in the ERT. The State believes that the stack test data submitted in the ERT, taken at face value, may be misleading unless the context in which the testing was completed is understood. Until the number and degree of source configuration and operation variables can be adequately accounted for and reported in one reporting tool, allowing the associated test data to be wholly considered, the State relies heavily upon the submission of written stack test reports. Thus, the commenter supports EPA's preservation of the submittal of written performance testing reports to state agencies, and requests that EPA consider a way for states to report to EPA via the ERT that the test is not approvable or was not representative.

Response: EPA agrees that the State and Local Air Pollution Control Agencies (S/Ls) should be able to continue to require stack test reports to be submitted in the format that best suits their needs. However, EPA encourages S/Ls to consider requiring the submission of stack test data electronically as well and the ERT is a readily available tool for S/Ls use. In response to the comment that the stack test data taken at face value may be misleading, EPA disagrees. EPA believes that the data and information required to be submitted in the ERT is the same data and information that is included in written performance test reports and will allow for an adequate review of the stack test and its conduct. The ERT was designed using existing performance test reports. All the data in test reports is also clearly required in the ERT. EPA does believe that the S/Ls have the expertise and knowledge of their sources, such as operation variables and source configuration, and would generally be better able to evaluate stack test reports. Thus, we have designed the ERT, in conjunction with WebFIRE (the repository for ERT data), to allow for S/Ls to conduct a third-party review of the performance test reports. Regarding the comment to have the S/Ls submit the data, EPA is designing the reporting to be submitted by the sources. Where the S/Ls have comments concerning a particular performance test, they need to discuss with the source and have the source resubmit the test report. We have concluded that having the source resubmit their performance test report electronically will eliminate the burden associated with tracking different versions of the test report in different formats.

Comment: One commenter (4770) requests that the reporting requirements in rules Da, Db and Dc be amended to commence on January 1, 2013 so that affected owners and operators have adequate time to familiarize themselves with the requirements and procedures for using the CDX and ERT. Until then, affected facilities should be allowed to continue to submit paper copies of test data to EPA. In addition, the reporting requirements should be changed to 90 days after completion of correlation and performance tests so that affected facilities have adequate time to gather required data and make adequate resources available to submit the data.

Response: EPA does not agree that the electronic reporting of performance test data through the Central Data Exchange using the Electronic Reporting Tool (ERT) needs to be extended for one year because the ERT is difficult to use. EPA believes that the source testing community, for the most part, has had plenty of experience in the past year using the ERT. EPA has also worked closely with the source testing community to understand and address their concerns with ease of use, so there is no need to extend the commencement date. We agree that it is appropriate to allow the required reports to be submitted 90 days after completion of correlation and performance tests. Among other things, this will provide time for owners/operators to familiarize themselves with ERT. Thus, we are extending the date for submitting the ERT report to 90 days.

2.6.4 Monitoring PM and Opacity Emissions from EGUs Using ESPs

Comment: One commenter (17755) states that the rule is not clear regarding how PM emissions will be monitored for EGUs using ESPs if and when the ESP is not running, e.g., during SSM or offline activities, and if the ESP is not running, commenter asks how these excess emissions will be detected using the ESP Predictive Model. The commenter states concerns that determining compliance with opacity and PM standards will be more complicated without some kind of continuous emission monitor in place. The commenter requests information and guidance on what constitutes an excess emission if there is no continuous emission monitor, and asks the following: how does the EPA anticipate that compliance with the emission limit be determined, would an inspector simply monitor and check all of the parameters established for the ESP Predictive Model, and if the ESP is operating outside the defined parameters is that considered an excess emission.

Response: During periods of startup and shutdown, the ESP predictive model would not apply and the owner/operator would be required to follow the specified work practice standards to minimize emissions.

2.7 Other Proposed Amendments

2.7.1 Rule Definitions

2.7.1.1 Definition of "Affected Facility"

Comment: One commenter (4836) stated that EPA's rationale for proposing to revise the definition of "affected facility" by adding integrated combustion turbines and fuel cells is vague and ambiguous, and the existing definition should not be revised. Another (4766) stated that EPA should provide additional clarification regarding the proposed expanded definition of "affected facility" under subpart Da to include "integrated" combustion turbines and fuel cells. Although discussed briefly in the preamble, the word "integrated" is still unclear and is not well-defined in the rule. In addition, although EPA suggests that its intent is to encourage and promote the use of such units, it is unclear how EPA's proposed regulation would accomplish that goal. Without further explanation, the new definition of "affected facility" remains vague and ambiguous and should be eliminated. One commenter (17852) also states that the option to integrate combustion turbines and/or fuel cells with steam generating units is another good way to reduce emissions. The commenter also states that if an owner chooses to integrate and connect a fuel cell or combustion turbine to a steam boiler to use waste heat to improve efficiency, they should be able to elect to consider them an integrated unit for compliance purposes.

Response: The definition has been clarified to specify that "integrated" means the device either supplies useful thermal output to the boiler or electrical output to power auxiliary equipment of the EGU. If the definition were not expanded to include integrated equipment, the intent of subpart Da could be circumvented by having auxiliary equipment provide steam to the EGU to increase the output of the EGU and decrease the corresponding output-based emissions rate without accounting for the emissions from the integrated equipment. The revised definition provides additional flexibilities to reduce emissions.

2.7.1.2 Definition of "Gaseous Fuel"

Comment: One commenter (5195) stated that EPA should clarify within subpart Da that the definition of "fossil fuel" does not include landfill gas, biogases or other materials such as engineered fuels that are produced from processing components of municipal solid waste. Because landfill gas and biogas are included under the proposed definition of "gaseous fuel," and the term "gaseous fuel" is included in the definition of "fossil fuel," there may be an ambiguity with respect to how these definitions relate to each other in implementing subpart Da. The commenter requests that EPA clarify the circumstances under which subpart Da may apply to gaseous fuel firing, where such gaseous fuel is not a fossil fuel (for example, where a non-fossil gaseous fuel is combusted in combination and/or alternately with a fossil-fuel).

Response: The definition of fossil fuel under subpart Da only includes fuels "created for the purpose of creating useful heat.' Since landfill gas and other fuels derived from municipal solid waste are not derived for the purpose of creating useful heat they are not considered fossil fuels under subpart Da. The definition of gaseous fuel includes these fuels strictly to determine the appropriate monitoring requirements in circumstances where non-fossil fuel gaseous fuels are burned in combination with fossil fuels. EGU are subject to the requirements of subpart Da when non-fossil fuel gaseous fuels are burned in combination with fossil fuels.

2.7.1.3 Definition of "IGCC Electric Utility Steam Generating Unit"

Comment: One commenter (4836) stated that EPA's proposed revised definition of "IGCC Electric Utility Steam Generating Unit" should be reworded to read "The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown or repair." Adding startup and commissioning would provide the EPA Administrator with additional authority to resolve any regulatory problems associated with the construction and initial operations of an IGCC EGU. Adding shutdown would allow an operator to combust natural gas for safety reasons during shutdown.

Response: The definition has been amended as suggested.

2.7.1.4 Definition of "Natural Gas"

Comment: One commenter (4836) notes that the proposed Subpart D definition of" natural gas", and the existing definitions of "natural gas" in 40 CFR 60 subparts Da, Db, and Dc, are slightly different from the definition of "natural gas" in Part 75. Another commenter (5749) stated that the definitions of "natural gas" used for the NSPS are different from the proposed definition of "natural gas" for the EGU NESHAP. The commenters recommend that EPA use this NSPS amendment rulemaking to make the definitions consistent in all of the rules to avoid confusion and unintended results.

Response: In an effort to make the definitions as consistent as possible, the definition of "natural gas" under the NSPS has been amended as follows: i) "maintains a gaseous state under ISO conditions" has been added; ii) the heating value range has been amended to 950 to 1,100 Btu/scf; iii) a statement that natural gas does not include "any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value," has been added; and, iv) a provision that the "maximum sulfur content is 20 grains per 100 standard cubic feet" has been added. The definition for industrial sources has historically included liquefied petroleum gas and will continue to do so. However, it will be removed for subpart Da affected EGUs to make it more consistent with that used in part 75.

2.7.1.5 Definition of "Petroleum Coke"

Comment: Several commenters (4765, 4836) object to including petroleum coke in the definition of "coal" for purposes of NSPS subpart Da. Reasons cited by the commenters are 1) EPA acknowledged in its NSPS Subpart Y rulemaking that petroleum coke "is a by-product residual from the thermal cracking of heavy residual oil during the petroleum refining process,"(74 FR 25,304, 25,316/1), and therefore is not coal at all; and as a result, the nature of the analysis required for setting NSPS would be different for petroleum coke as compared to coal; 2) EPA has failed to provide emissions data as to whether EPA's proposed NSPS for PM, NO_X or SO_2 are achievable when petroleum coke is burned in a EGU, either during periods of normal operation or during periods of startup and shutdown.

Response: When subpart Da was originally promulgated, petroleum coke was not as commonly used in utility boilers. Subsequently, when EPA finalized the industrial boiler NSPS, subpart Db, petroleum coke was recognized as a valuable fuel that has characteristics similar to coal and was therefore included in the definition of coal. From analysis of emissions data from facilities burning petroleum coke EPA has concluded that EGUs burning petroleum coke are able to achieve the amended criteria pollutant standards for coal-fired units.

The Northside 1A and 1B EGUs and the Manitowoc 9 petroleum coke-fired EGUs are achieving the PM standard, the AES Deepwater petroleum coke-fired EGU is achieving the NO_X standard, and the Northside 1A facility is achieving the combined NO_X + CO standard. While none of the petroleum coke-fired EGUs are achieving the amended SO_2 standard, the SO_2 technology is directly transferrable and other facilities burning high sulfur fuels have demonstrated that 97% reduction in potential SO_2 emissions is achievable. Furthermore, the recent permit for the proposed Las Brisas Energy Center indicates that the amended NO_X and SO_2 standards are achievable for a new petroleum coke-fired EGU. The proposed Las Brisas Energy Center would burn petroleum coke in a fluidized bed using subcritical steam conditions. The permit conditions for NO_X and SO_2 are 0.070 lb/MMBtu and 0.114 lb/MMBtu respectively. The gross EGU efficiency would only have to be 34% (achievable using subcritical steam conditions) and 38% (achievable with supercritical steam conditions) to comply with the amended NO_X and SO_2 standards, respectively. In addition, based on the sulfur content of the petroleum coke, the SO_2 control is designed to control over 97% of the potential SO_2 emissions.

2.7.2 General Duty

Comment: One commenter (4836) stated that EPA's proposal to add to Subpart Da a provision imposing a "general duty to minimize emissions" is neither necessary nor appropriate. Subpart Da facilities already are subject to the general duty under 40 CFR 60.11(d).

Response: EPA agrees that it is not necessary to include a specific provision imposing a "general duty to minimize emissions" in Subpart Da for the reason the commenter articulates. The provision has, therefore, been removed.

2.7.3 Affirmative Defense Provisions

Comment: One commenter (5210) stated that EPA's proposed inclusion of the "affirmative defense" for malfunctions is unlawful and contravenes the CAA. The commenter states that the CAA clearly sets forth how the courts are to assess civil penalties, whether the case is brought by a citizen or EPA. 42 U.S.C. § 7413(e). By allowing an affirmative defense in the case of malfunction, EPA goes directly against two expressed intentions of Congress: 1) the burden it places on citizens makes it less likely that they will enforce the CAA, see, e.g., Pennsylvania v. Del. Valley Citizens' Council for Clean Air, 478 U.S. 546, 560 (1986);and 2) several of the factors at issue in the affirmative defense undercut Congress's intent that citizen suit enforcement should avoid re-delving into "technological or other considerations, "NRDC v. Train, 510 F.2d 692, 700 (D.C. Cir. 1974). Both result from the technical burden EPA imposes on citizens with the affirmative defense, and both render the defense impermissible. In addition to these problems, there is simply no need for an affirmative defense to penalties to be written into the regulations. EPA has discretion to decide what cases to prosecute, to consider settlements, and to request civil penalties in a case-by-case manner, as long as it acts consistent with the CAA to protect clean air as its top priority, see U.S.C. § 7401. If EPA has the authority to promulgate any type of "affirmative defense", then the commenter made specific recommendations for the provisions of such "affirmative defense". Several commenters (4714, 4770, 4830, 4997) stated that the proposed "affirmative defense" provisions to be added to subpart Da need clarifications, are vague or contradictory, and impose requirements that mean that the defense will be entirely useless as a practical matter. Some of the nine requirements that EPA proposed be met in order for a facility to claim an affirmative defense for a malfunction are unreasonable, difficult to demonstrate, and subject to varying interpretation. EPA should revise the affirmative defense provisions in the rule so that the requirements are meaningful to implement. The commenters provided specific recommended changes to the proposed rule language to address these issues. Another commenter (17975) states that EPA has not determined whether some emission control technologies are prone to malfunctions, or explained why EGUs that rely on such equipment should be entitled to an affirmative defense when it breaks down. Requiring government agencies to evaluate and rebut affirmative defenses on a case by case basis is impractical and has proved ineffective.

Response: EPA is finalizing emission standards that apply at all times, including during periods of malfunction. For malfunctions, the EPA is finalizing the proposed affirmative defense language for exceedances of the numerical emission limits that are caused by malfunctions. As EPA explained in the preamble to the proposed rule, EPA recognizes that even equipment that is properly designed and maintained can fail and that such failure can cause an exceedance of the relevant emission standard. The EPA included an affirmative defense in the final rule in an attempt to balance a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source.

With respect to the Affirmative Defense and the comment that the provisions are vague or contradictory, the EPA's view is that the affirmative defense is consistent with CAA sections 113(e) and 304 and the EPA has concluded that courts are well equipped and often do evaluate and apply the type of criteria set forth in the affirmative defense. Many of the conditions were modeled after the conditions of the affirmative defense in EPA's SIP SSM policy, which several states have adopted into their SIPs. (See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). We do not have any indication that parties to enforcement proceedings have had any significant difficulties applying the terms of these SIP affirmative defenses. In addition, EPA's view is that use of consistent terms in establishing affirmative defense regulations and policies across various CAA programs will promote consistent implementation of those rules and policies. The affirmative defense does not require a facility to prove its innocence rather than requiring an enforcement authority to prove a violation of the CAA or change the burden of proof with respect to establishing a violation. The affirmative defense applies to penalties and thus is only utilized where a violation has been established. The burden of proof remains with the plaintiff in an enforcement action. See, e.g., 40 C.F.R. 22.24. If a violation has been established and a source wishes to assert the affirmative defense with respect to penalties, the source does bear the burden of establishing that the elements of the affirmative defense have been met. This burden-shifting is appropriate because the source is in a better position to determine the facts required to establish the defense. See, e.g., Arizona Pub. Serv. Co. v. EPA, 562 F.3d 1116, 1120, 1129-30 (10th Cir. 2009) (rejecting industry challenge to EPA's use of an affirmative defense to address excess emissions during malfunction events.).

Comment: One commenter (4714) states that the proposed rules should be revised to enable EPA to allow state rules for affirmative defense that are EPA-approved as part of a state implementation plan (SIP) to be used in lieu of the federal procedures. This flexibility would eliminate duplicative or potentially even conflicting requirements for both state agencies and regulated entities.

Response: As a general matter, state SIP provisions do not apply in the context of an EPA promulgated NSPS. States can, and in fact are encouraged to, take delegation of the authority to implement and enforce the requirements of NSPS; however, in such circumstances, it is still the provisions of the NSPS that apply, not EPA-approved SIP provisions. EPA, therefore, concludes that inclusion of the Affirmative Defense in the NSPS is appropriate.

Comment: One commenter (4714) states that an initial notification is required if an affected owner/operator wishes to claim an affirmative defense and the proposed rule allows notification by either telephone or facsimile. The commenter states that an electronic reporting mechanism should be allowed for this initial notification. However, telephone notifications should not be allowed because such notifications are difficult to verify and enforce. At a minimum, electronic notification that complies with EPA's Cross-Media Electronic Reporting Regulation (CROMERR) standards could provide for quick and durable reporting that may be relied upon for investigative and enforcement purposes.

Response: The EPA accepts documents in electronic format, as long as the format is compatible with the requirements of the standards. For the affirmative defense provisions, the owner or operator of a facility experiencing an exceedance of its emission limit(s) during a malfunction must notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, or if it is not possible to determine within two business days after the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period. The written reports required to demonstrate that the affirmative defense provisions have been met and requests for an extension of the deadline for submitting these reports may also be submitted electronically. EPA has concluded that notification by telephone is appropriate since that notification must by followed by submission of a written report demonstrating that the affirmative defense provisions, including the notification requirement, have been met.

2.7.4 Subpart Da Mercury Provisions

Comment: Several commenters (4836, 5715) state that it is appropriate to remove the applicable mercury emissions standards provisions vacated by a federal court ruling from the NSPS under 40 CFR 60 subpart Da).

Response: The provisions have been removed. In addition, the amendments to subpart B that occurred as part of the Clean Air Mercury Rule have also been removed.

2.7.5 Removal of References to 30-Day Rolling Averages

Comment: One commenter (4836) stated that EPA's proposed removal of references to 30-day rolling averages in Subpart Da provisions establishing emission limitations and the addition of new provisions stating that compliance with emission limits in various sections "are determined on a 30-day rolling average basis" does not appear to be intended to change the averaging time of any provision, but could cause confusion and should be better explained.

Response: The revisions are only intended to make the rules easier to read and are not intended to change any of the existing provisions.

2.7.6 Deletion of Obsolete Provision References in Rule

Comment: One commenter (4698) supports EPA proposal to delete "emergency condition" requirements for the SO_2 standard exemption, references to percent reductions for NO_X and PM, references to the term "solvent refined coal," and the existing commercial demonstration permit references.

Response: The provisions have been removed

2.7.7 Proposed Rule Language Corrections and Clarifications

Comment: One commenter (4698) states that in §60.48Da(k)(1)(i) the term "O_{sg}" in Equation 2 should be defined as "Average hourly gross energy output from electric utility steam generating unit" to be consistent with the rule's definitions.

Response: A "steam generating unit" is a subset of an "electric utility steam generating" and EPA has concluded that the suggested change is not necessary.

3. Response to Comments on Proposed NSPS Amendments to Subparts Db and Dc

3.1 Definition of "Distillate Oil"

Comment: Several commenters (4698, 4770, 4841) support EPA's proposal to expand the definition of "Distillate oil" in both 40 CFR 60 subparts Db and Dc to include biodiesel and kerosene because it is appropriate to have the same requirements for units burning biodiesel or kerosene as those units firing distillate fuel oil. One commenter (5749) requested that EPA explain why the definition for "distillate oil" in 40 CFR 60 subpart Db of the NSPS includes a limitation on the weight percent nitrogen, while the proposed definition for "distillate oil" in the EGU NESHAP does not.

Response: The definition of distillate oil has been amended as proposed. When the industrial boiler NSPS was originally promulgated, certain provisions in the NSPS assumed low fuel NO_X formation and that requires low fuel nitrogen content. This is not necessary for purposes of the EGU NSPS.

3.2 Exemption of Steam Generating Units Subject to Other NSPS

Comment: One commenter (4841) supports EPA's proposal to i) exempt owners and operators of affected facilities subject to 40 CFR 60 subpart Eb (standards of performance for large municipal waste combustors (MWCs) and 40 CFR 60 subpart CCCC (standards of performance for commercial and industrial solid waste incineration) from 40 CFR part 60, subpart Da; ii) exempt owners/operators of affected facilities subject to 40 CFR part 60, subpart BB (standards of performance for Kraft pulp mills) from the PM standards under subpart Db; and, iii) exempt owners/operators of fuel gas combustion devices subject to 40 CFR 60 subpart Ja (standards of performance for petroleum refineries) from the SO_2 standard under 40 CFR 60 subpart Db.

Response: The exemptions are included in the final rule.

3.3 Applicability to Temporary Boilers

Comment: One commenter (4766) stated that EPA appears to suggest that separate NSPS requirements should apply to temporary boilers that are on-site for 30 days or less. However, temporary boilers, especially those brought on-site on skids or trucks for construction projects, are not stationary equipment and therefore do not fall under NSPS. In any event, even if such temporary sources could be considered "stationary," 30 days is not enough time to implement the NSPS.

Response: Section 111(a)(3) defines a "stationary source" as "any building, structure, facility or installation which emits or may emit any air pollutant." Temporary boilers as described by the commenter are stationary sources within the meaning of this definition and are, therefore, subject to the NSPS requirements applicable to boilers in the relevant size category. This conclusion is supported by section 302(z) of the CAA which defines stationary source emissions to include all emissions except those resulting directly from internal combustion engines for transportation purposes or from nonroad engines or nonroad vehicles as defined in section 7550 of the CAA. Temporary boilers are not internal combustion engines and as such are not nonroad engines or nonroad vehicles as defined in section 7550. The fact that they may only be on site for a period of 30 days or less does not alter their status as stationary sources as there is no temporal aspect to section 111(a)(3)'s definition of "stationary source." In recognition of the special considerations associated with temporary boilers the final rule exempts temporary boilers that burn natural gas and/or low sulfur distillate oil from the NSPS. The requirement to limit temporary boilers fuels to inherently cleaner burning fuels minimizing emissions while providing flexibility to the regulated community.

The definition added to 40 CFR 60 subparts Db and Dc is as follows:

> *Temporary boiler* means any generating unit that combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less, and that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

3.4 Site-Specific Monitoring Plan

Comment: One commenter (4674) requests that EPA provide further guidance on the "written site-specific monitoring plan approved by the permitting authority," under 40 CFR 60.47c(h). Specifically, the commenter requests that EPA allow permitting authorities to authorize less stringent opacity or other monitoring requirements than identified in the rule. For example, a permitting agency could require affected owners and operators to conduct opacity testing only upon using a fuel for operational reasons rather than for compliance demonstrations. Further, a permitting agency could specify that each periodically required Method 9 does not have to adhere to the 40 CFR part 60 notification and reporting requirements associated with performance tests found in §60.8 and §60.11, but rather the affected owner or operator would be required to submit any deviations with the excess emissions report required under §60.48c(c).

Response: There are no specific requirements in §60.47c(h). The permitting authority for the owner/operator of the affected steam generating unit determines appropriate procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard on a site-specific basis. The source specific requirements could be as described in the comment as long as the permitting authority has determined they are appropriate for a specific affected facility.

3.5 Opacity Monitoring

Comment: One commenter (4674), a state air pollution control agency, recommends that EPA consider removing the requirement to complete subsequent Method 9 opacity performance tests after the initial performance test is completed, if the affected owner or operator is able to show in the initial reading that the opacity complies with the standard. It is the experience of the commenter that subsequent opacity readings for sources which have not exceeded the standard are onerous and may actually discourage good air pollution control practices. Alternately, the State suggests that EPA consider expanding the extension associated with proposed changes to 40 CFR 60.47c(a)(1)(i). EPA proposed a change to allow affected owners and operators to extend the time frame to complete a Method 9 performance test from a minimum of every 12 months for sources where the initial performance test showed that there were no visible emissions. EPA proposes to allow those sources to either repeat the performance test every month or within 45 days of using a fuel with an opacity standard. Without the latter option, sources which primarily combust natural gas are often required to undergo a special startup using diesel fuel solely to satisfy the current compliance requirement to complete a Method 9 performance test every 12 months. As proposed, those sources will now only be required to complete a Method 9 performance test within 45 days of using diesel fuel, which will be dependent on the sources' operational needs and not a compliance requirement. The State is in agreement with EPA's proposed revision to 40 CFR 60.47c(a)(1)(i). However, this proposed extension is only available to facilities that have no visible emissions observed during the initial 60 minute Method 9 performance test. Pursuant to 40 CFR 60.47c(a)(1)(ii-iv), sources which have *any* 6-minute opacity average greater than 0% must conduct another Method 9 performance test for compliance purposes in the near term (every 6 months, 3 months, or more frequently). It is the commenter's experience that all boilers running on diesel experience some degree of opacity during operation, which typically subsides quickly. At least one 6-minute opacity average is likely to exceed 0%. For many of the State's sources, the primary fuel used is natural gas, and diesel fuel is used only as a backup. Because these sources are likely to have at least one 6-minute opacity average greater than 0% while using diesel fuel, they are required to repeat the Method 9 performance test even if they have ceased using diesel fuel in the interim. Repeating this performance test requires the affected owner or operator to shut down the boiler and restart using diesel fuel, only to shut down once again to restart using natural gas. It is the State's experience that, left to the operational needs of the source, a boiler may only utilize diesel fuel once every few years as opposed to the compliance requirement to use diesel fuel every few months. It appears that the 45-day allowance, while intending to limit unnecessary opacity monitoring for sources with no visible emissions, was not extended to sources which may have some visible emissions during operation. Therefore, such sources are required to regularly shutdown their equipment and restart on diesel just to complete the necessary opacity readings. The State suggests that either EPA extend the 45-day allowance to 40 CFR 60.47c(a)(1)(ii-iv), or that a permitting agency may authorize an alternative opacity monitoring schedule by means of the site-specific monitoring plan as discussed §60.47c(h).

Response: Under subpart Dc §60.47c(h), state permitting authorities have the ability to develop an alternate opacity monitoring plan to alleviate the above concerns. To minimize burden, the 45 day testing allowance has been added to all subparts.

2012
- NSPS proposal

2013

2014
- Plant Ratcliffe

2015
- Texas Clean Energy Project
- Indiana Gasification

2016
- Taylorville Energy Center

Carbon Capture Demonstration Projects of Interest						
Scheduled Date of Operation	Project Name	State	Description	Capture Type	DOE Funding	Status/Additional Details
2014	Plant Ratcliffe Mississippi Power	MS	Air-blown 582 MW IGCC plant using a coal-based transport gasifier	Pre-combustion	$270 million	Being constructed
2015	Texas Clean Energy Project Summit Power Group	TX	400 MW IGCC polygeneration plant	Pre-combustion	$450 million	CPS Energy signed a PPA with Summit Power Group in January 2012
2015	Indiana Gasification Leucadia	IN	Coal gasification project that includes a methanation process to produce pipeline quality synthetic natural gas	Pre-combustion	TBD	Public comment period on draft PSD and operating permits closed January 30, 2012
2016	Taylorville Energy Center Tenaska	IL	602 MW IGCC power plant	Pre-combustion	$2.579 billion loan guarantee	Being debated in state legislature

Sources: Global CCS Institute
Indiana Department of Environmental Management
Chicago Tribune

D. These projects are not shovel ready
· included in transitional category (18 units)?

Potential Impacts on Small Entities (cont.)

Case Study: 250-MW pulverized coal plant with heat rate of 9,930 Btu/kWh

Efficiency Improvement Technology	Heat Reduction, Btu/kWh	Capital Cost, $
Installation of Neural Network process controls	25	0.5 million
Installation of new air heaters	92	2.0 million
Steam turbine upgrade	255	10.2 million
Improve steam turbine seals	15	0.3 million
Overhaul/upgrade of boiler feed pump	37	0.3 million
Total	424 ~4% from base heat rate	**13.3 million**

- Potential small entity impacts for new coal-fired boilers
  - New coal-fired supercritical plant with net power output of 800 MWe
    - Capital costs of ~$2.7 billion
    - Annual cost of ~$0.5 billion/year
  - New IGCC plant with net power output of 800 MWe
    - Capital costs of ~$3.5 billion
    - Annual cost of ~$0.6 billion/year

OAQPS

Sources: Sargent & Lundy Final Report – Coal-Fired Power Plant Heat Rate Reductions, January 2009; EPA White Paper – Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units, October 2010

Sample of EPA NSR Lawsuits and Targeted Projects

- Air Heaters
  - Sierra Club v. Dairyland Power Coop. (filed in 2010)
  - NOVs issued to American Municipal Power & Painesville Municipal Elec. Plant (2009)
- Steam Turbine Upgrade
  - Conservation Law Found. v. Public Service of New. Hamp. (filed in 2011)
  - United States v. Ameren (filed in 2011)
  - U.S. v. AEP, U.S. v. Cinergy , U.S. v. Duke Energy (filed in 1999)
  - Mississippi Power Company 114 Letter
- Boiler Feed Pumps
  - New York v. Niagara Mohawk Power Corp. (filed in 2005)
  - NOV issued to Nebraska Public Power District (2008)

Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act

Source: http://www.epa.gov/airquality/pdfs/111background.pdf

Clean Air Act section 111 establishes mechanisms for controlling emissions of air pollutants from stationary sources. Section 111(b) provides authority for EPA to promulgate New Source Performance Standards (NSPS) which apply only to new and modified sources. Once EPA has elected to set an NSPS for new and modified sources in a given source category, section 111(d) calls for regulation of existing sources with certain exceptions explained below.

Specifically, section 111(b) of the CAA requires EPA to establish emission standards for any category of new and modified stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." EPA has previously made endangerment findings under this section for more than 60 stationary source categories and subcategories that are now subject to NSPS.[1] An endangerment finding would be a prerequisite for listing additional source categories under section 111(b), but is not required to regulate GHGs from source categories that have already been listed, such as EGU's at power plants and refineries.

For listed source categories, EPA must establish "standards of performance" that apply to sources that are constructed, modified or reconstructed after EPA proposes the NSPS for the relevant source category.[2] However, EPA has significant discretion to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered, and set the level of the standards.

Section 111 gives EPA significant discretion to identify the facilities within a source category that should be regulated. To define the affected facilities, EPA can use size thresholds for regulation and create subcategories based on source type, class or size. Emission limits also may be established either for equipment within a facility or for an entire facility.

EPA also has significant discretion to determine the appropriate level for the standards. Section 111(a)(1) provides that NSPS are to "reflect 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." This level of control is commonly referred to as best demonstrated technology (BDT). In determining BDT,

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[1] EPA has developed NSPS for more than 70 source categories and subcategories. However, endangerment findings apply to the categories as a whole, while subcategories within them have been established for purposes of creating standards that distinguish among sizes, types, and classes of sources.

[2] Specific statutory and regulatory provisions define what constitutes a modification or reconstruction of a facility. 40 CFR 60.14 provides that an existing facility is modified, and therefore subject to an NSPS, if it undergoes "any physical change in the method of operation . . . which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 40 CFR 60.15, in turn, provides that a facility is reconstructed if components are replaced at an existing facility to such an extent that the capital cost of the new equipment/components exceed 50 percent of what is believed to be the cost of a completely new facility.

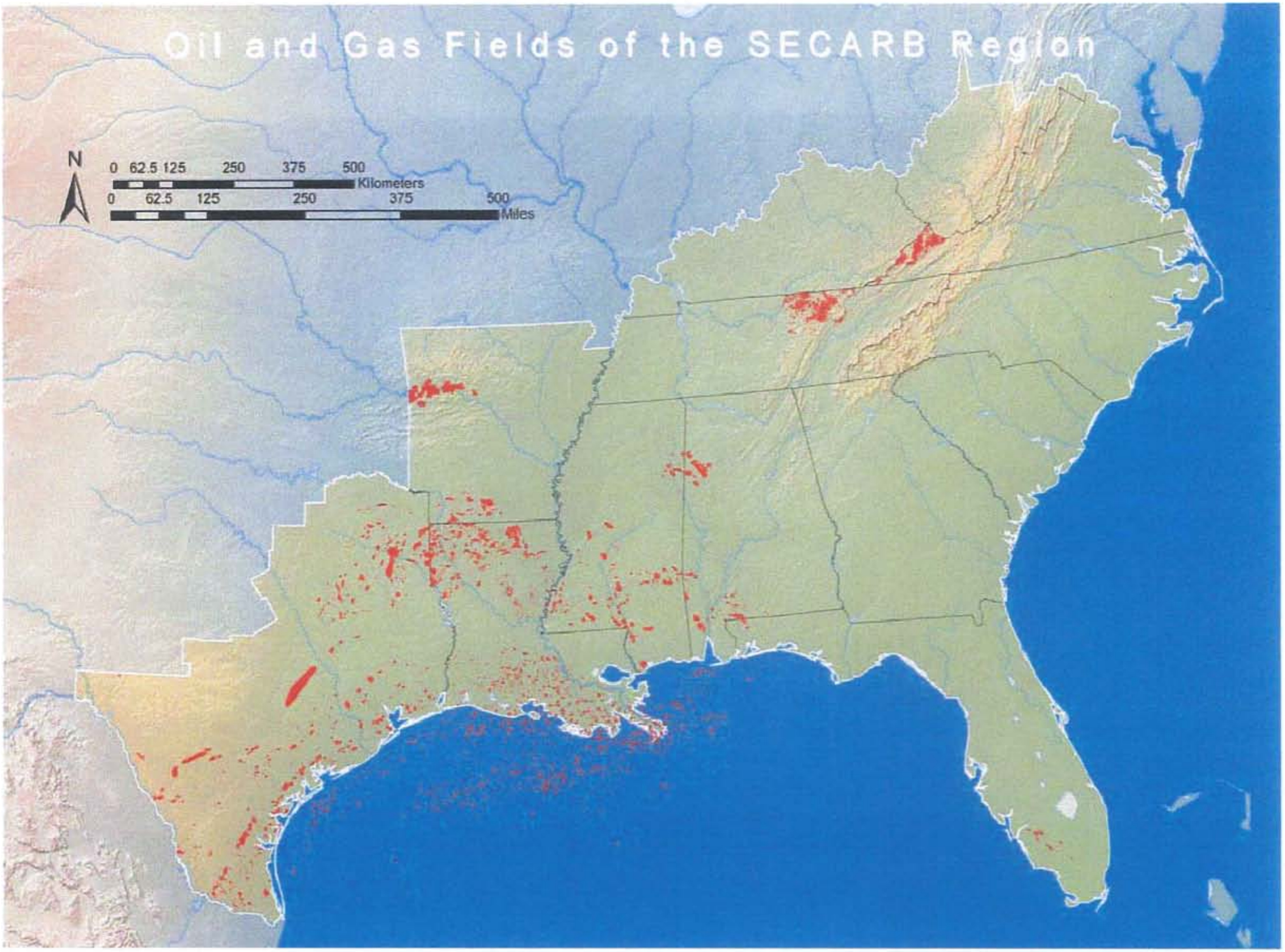
EPA typically conducts a technology review that identifies what emission reduction systems exist and how much they reduce air pollution in practice. This allows EPA to identify potential emission limits. Next, EPA evaluates each limit in conjunction with costs, secondary air benefits (or disbenefits) resulting from energy requirements, and non-air quality impacts such as solid waste generation. The resultant standard is commonly a numerical emissions limit, expressed as a performance level (i.e. a rate-based standard). While such standards are based on the effectiveness of one or more specific technological systems of emissions control, unless certain conditions are met, EPA may not prescribe a particular technological system that must be used to comply with a NSPS. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions.

Costs are also considered in evaluating the appropriate standard of performance for each category or subcategory. EPA generally compares control options and estimated costs and emission impacts of multiple, specific emission standard options under consideration. As part of this analysis, EPA considers numerous factors relating to the potential cost of the regulation, including industry organization and market structure; control options available to reduce emissions of the regulated pollutant(s); and costs of these controls.

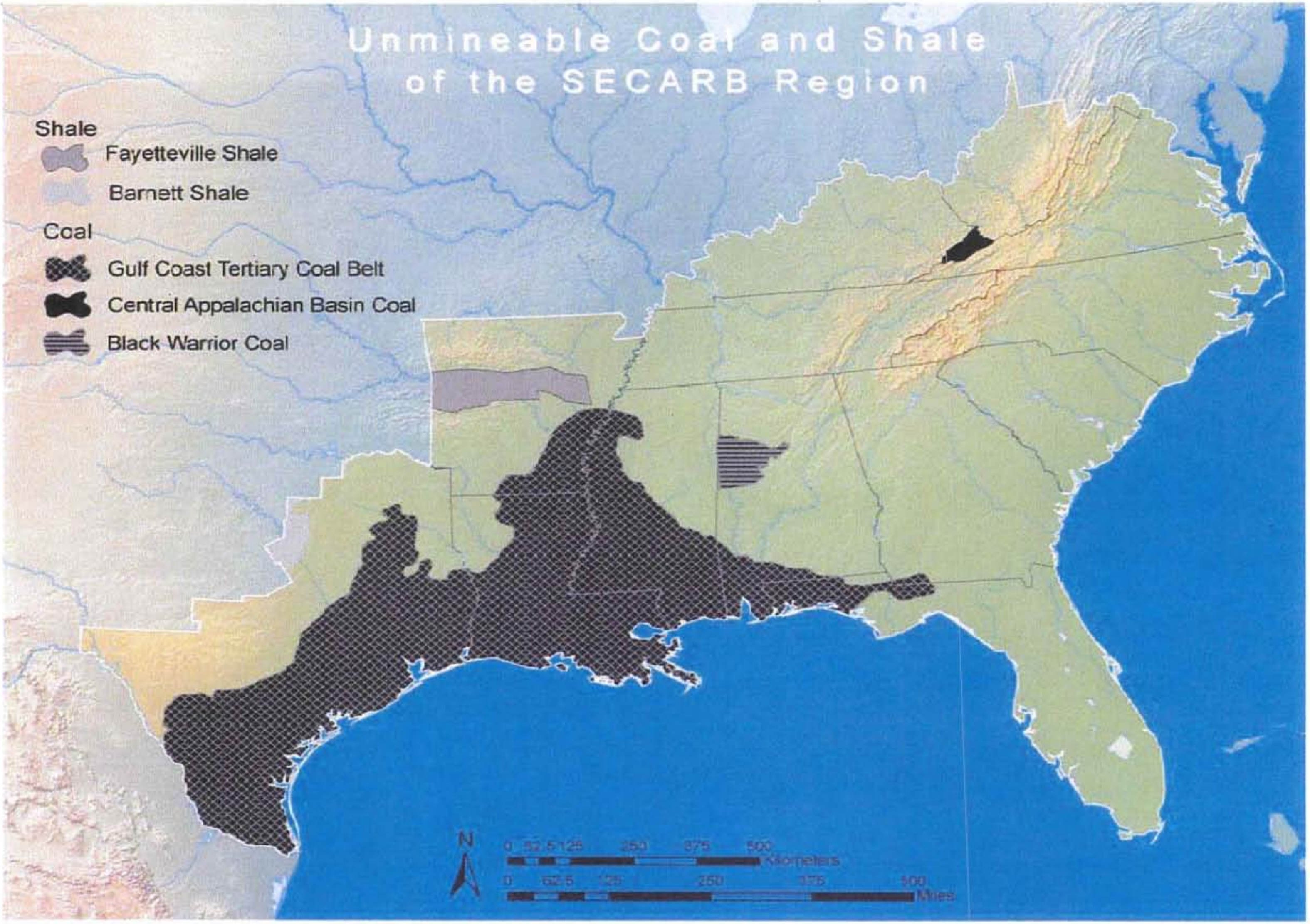
Section 111(d) requires regulation of existing sources in specific circumstances. Specifically, where EPA establishes a NSPS for a pollutant, a section 111(d) standard is required for existing sources in the regulated source category (except for pollutants regulated under the CAA section 109 requirements for national ambient air quality standards or regulated under the CAA section 112 requirements for hazardous air pollutants). Section 111(d) also uses a different regulatory mechanism to regulate existing sources than section 111(b) uses for new and modified sources in a source category. Instead of giving EPA direct authority to set national standards applicable to existing sources in the source category, section 111(d) provides that EPA shall establish a procedure for states to issue performance standards for existing sources in that source category. Under the 111(d) mechanism, EPA first develops regulations known as "emission guidelines." These may be issued at the same time or after an NSPS for the source category is promulgated. Although called "guidelines," they establish binding requirements that states are required to address when they develop plans to regulate the existing sources in their jurisdictions. These state plans are similar to state implementation plans under CAA section 110 and must be submitted to EPA for approval. Historically, EPA has issued model standards for existing sources that could then be adopted by states. In the event that a state does not adopt and submit a plan, EPA has authority to then issue a federal plan covering affected sources.

Section 111(d) guidelines, like NSPS standards, must reflect the emission reduction achievable through the application of BDT. However, both the statute and EPA's regulations implementing section 111(d) recognize that existing sources may not always have the capability to achieve the same levels of control at reasonable cost as new sources. The statute and EPA's regulations in 40 CFR 60.24 permit states and EPA to set less stringent standards or longer compliance schedules for existing sources where warranted considering cost of control; useful life of the facilities; location or process design at a particular facility; physical impossibility of installing necessary control equipment; or other factors making less stringent limits or longer compliance schedules appropriate.

Under CAA section 111, EPA possesses authority to distinguish among classes, types and sizes of sources within existing categories for purposes of regulating GHG emissions. For example, EPA has at times distinguished between new and modified/reconstructed sources when setting the standards. This may be appropriate, for instance, when a particular new technology may readily be incorporated into a new installation, but it may be technically infeasible or unreasonably costly to retrofit this technology to an existing facility undergoing modification or reconstruction. Alternatively, EPA has distinguished among sources within a category, for instance fossil fuel-fired boilers, for which EPA has subcategorized on the basis of fuel types (e.g., coal, oil, natural gas).

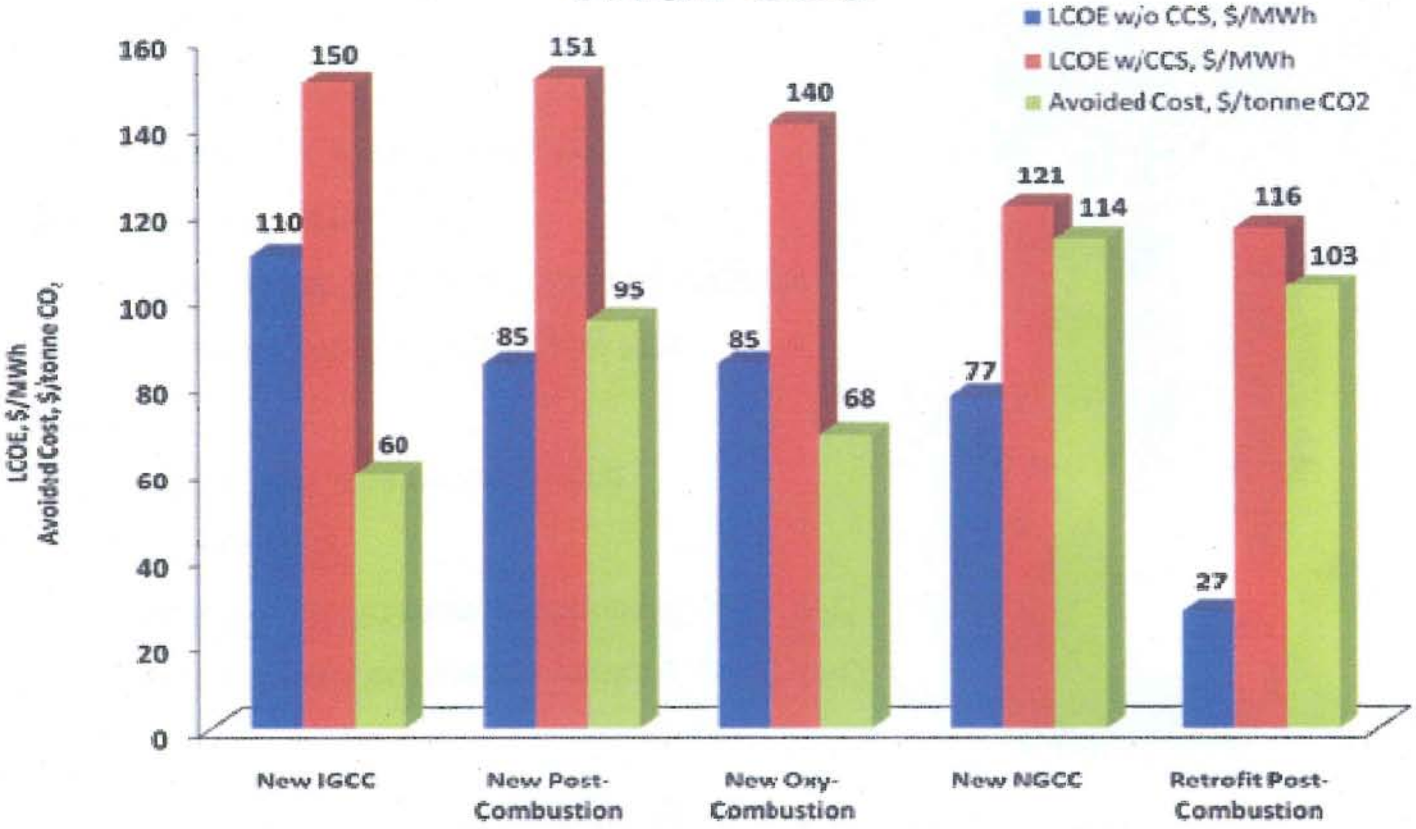


Source: From the 2010 Carbon Sequestration Atlas of the United States and Canada – Third Edition (Atlas III)
http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/2010AtlasIII_SECARB.pdf



Source: From the 2010 Carbon Sequestration Atlas of the United States and Canada – Third Edition (Atlas III)
http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/2010AtlasIII_SECARB.pdf

Comparison of Cost Metrics for Different Types and Configurations of Power Plants Equipped with CCS



The figure above shows the levelized cost of energy (LCOE) ranges depending upon the type of facility and whether the application is for a new plant or a retrofit of an existing plant. "New Post-Combustion" represents a new supercritical pulverized coal plant and the "Retrofit Post-Combustion" represents the existing fleet of power plants.

Source: Figure 2-6. From the DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap (DEC. 2010)
http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf

Deployment Barriers for CO_2 Capture On New and Existing Coal Plants Today

1. **Scale-up**
   - Current Post Combustion capture ~200 TPD
   - 550 MWe power plant produces 13,000 TPD
2. **Energy Penalty**
   - 20% to 30% less power output
3. **Cost**
   - Increase Cost of Electricity by 80%
   - Adds Capital Cost by $1,500 - $2,000/KW
4. **Regulatory framework**
   - Transport — pipeline network
   - Storage
5. **Economies of Scale**
   - Land, power, water use, transportation, process components, ...

NATIONAL ENERGY TECHNOLOGY LABORATORY

From the presentation "The U.S. Department of Energy's Carbon Dioxide Capture RD&D Program" given at the2011 NETL CO2 Capture Technology Meeting (Aug. 22 –Aug. 26, 2011 in Pittsburgh, PA) by Jared Ciferno, Technology Manager, Existing Plants Program

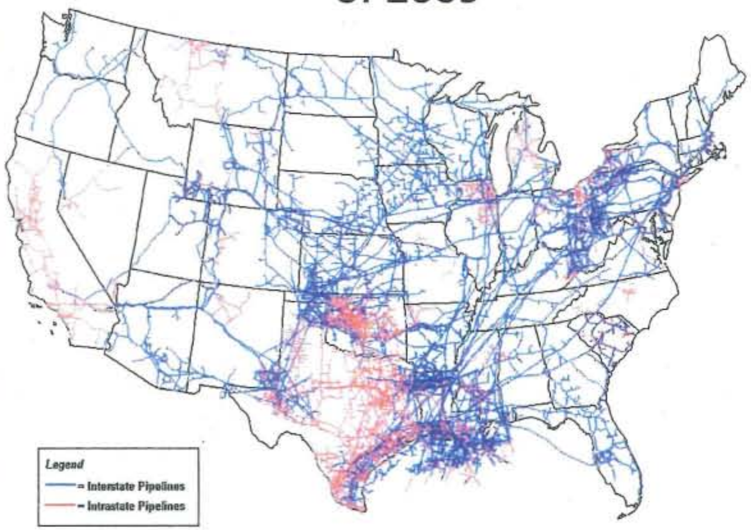
Source: http://www.netl.doe.gov/publications/proceedings/11/co2capture/presentations/1-Monday/22Aug11-Ciferno-NETL%20CO2%20Capt%20Program.pdf

Pipelines

Current CO2 Pipelines in the United

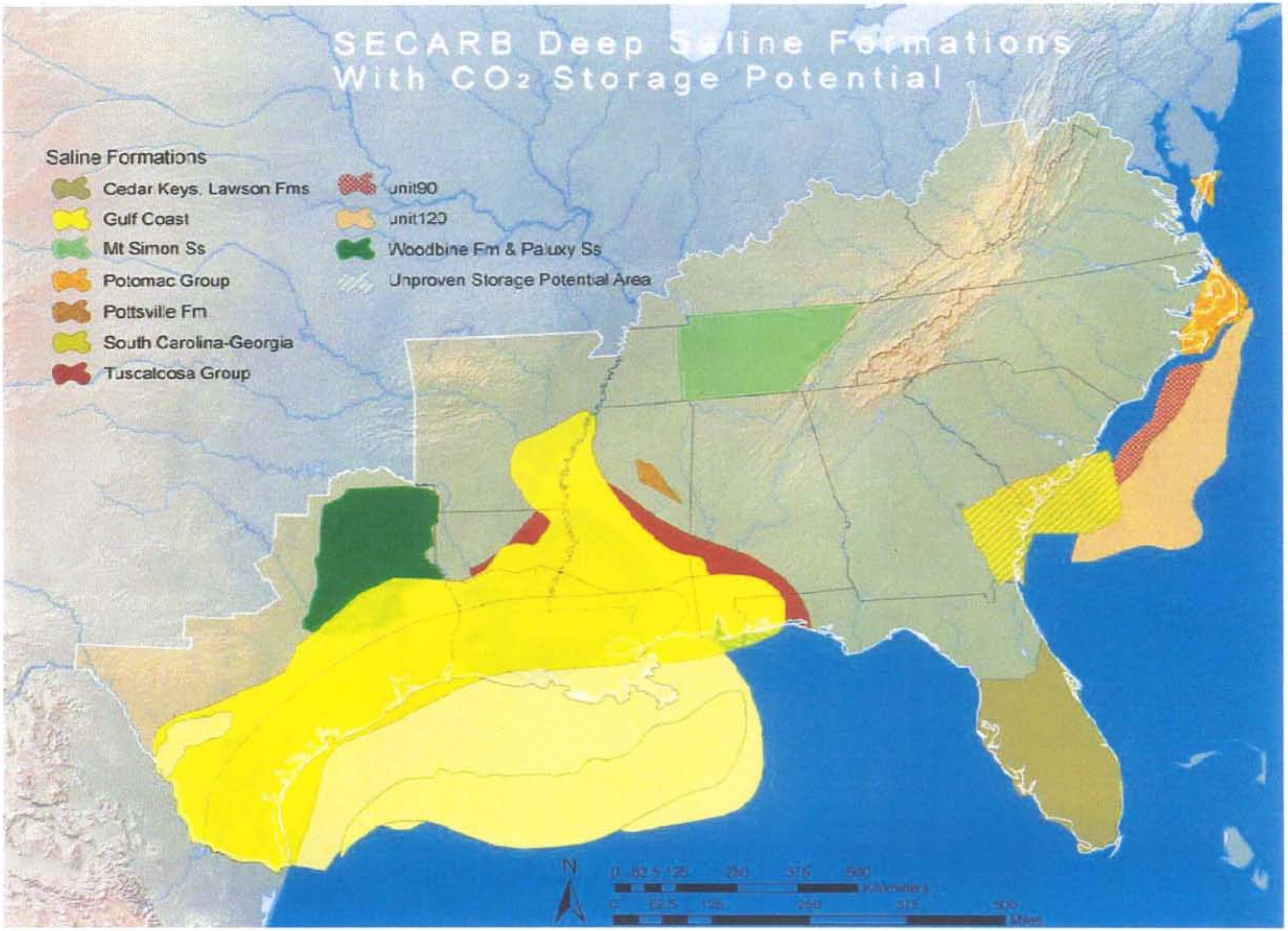
Source: Figure 3-4 From the DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap (DEC. 2010)
http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf

U.S. Natural Gas Pipeline Network as of 2009



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Source:
http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/ngpipelines_map.html



Source: From the 2010 Carbon Sequestration Atlas of the United States and Canada – Third Edition (Atlas III)
http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/2010AtlasIII_SECARB.pdf

Potential U.S. Geological Storage Formations

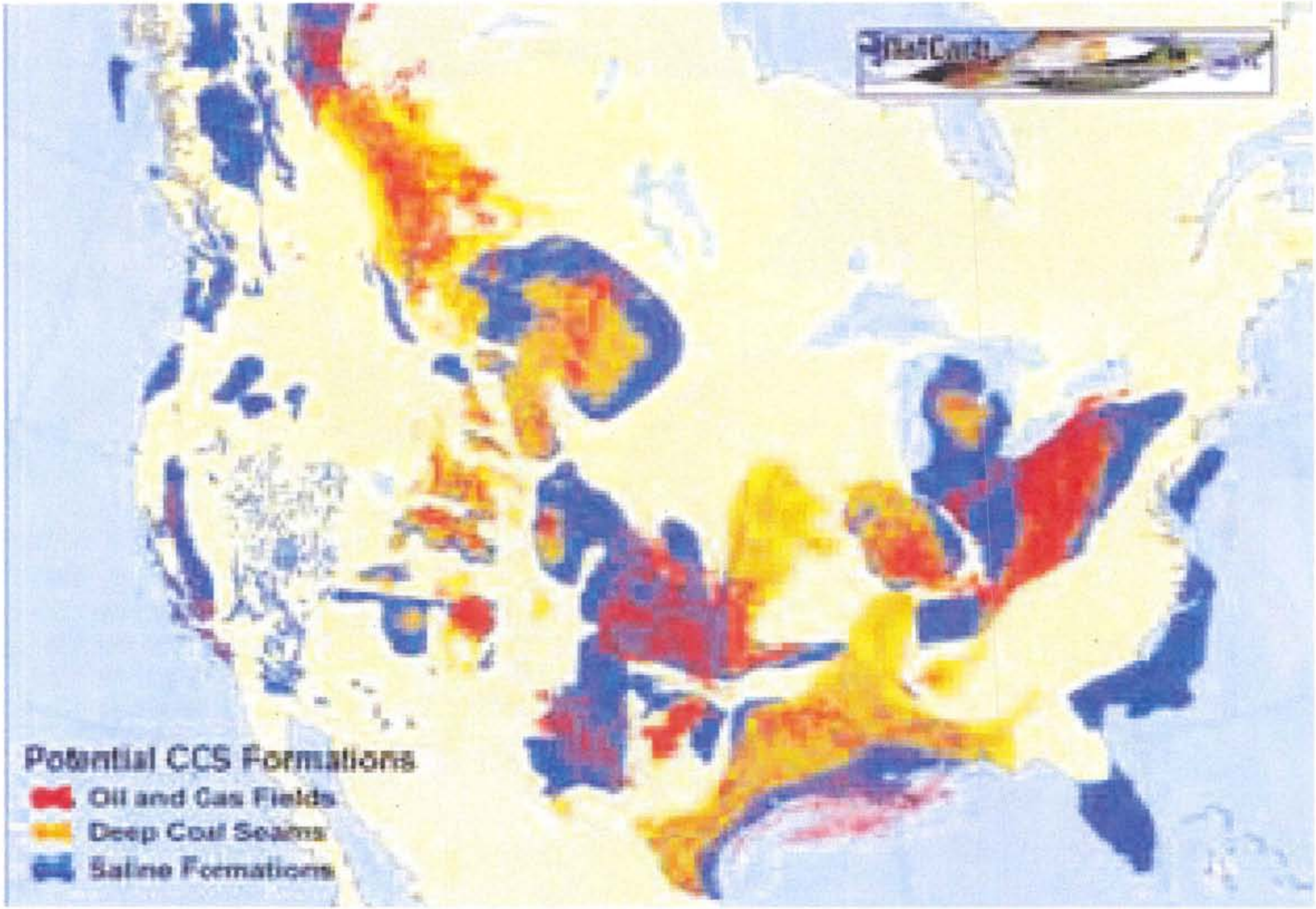


Figure 1-8 From the DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap (DEC. 2010)
Source: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

SOUTHERN COMPANY'S RESPONSE
TO
EPA'S PLANNED RULEMAKING FOR GHG NSPS FOR FOSSIL FUEL FIRED POWER PLANTS

Docket ID: EPA-HQ-OAR-2011-0090

Southern Company
600 North 18th Street
Birmingham, AL 35203
March 18, 2011

Southern Company appreciates the opportunity to respond to the U.S. Environmental Protection Agency's (EPA) planned rulemaking for greenhouse gas (GHG) new source performance standards (NSPS) for fossil fuel fired power plants.

Southern Company is one of the largest generators of electricity in the nation; serving both regulated and competitive markets across the southeastern U.S. Southern Company participates in all phases of the electric utility business with more than 42,000 megawatts of electric generating capacity and more than 27,000 miles of transmission lines. Southern Company provides electric service to over 4.4 million retail customers through its subsidiaries Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. In addition, Southern Power, the Company's competitive wholesale generation business, is among the largest wholesale energy providers in the Southeast, meeting the electricity needs of municipalities, electric cooperatives and investor-owned utilities. Other major subsidiaries include Southern Renewable Energy, which develops and invests in renewable energy projects; Southern Nuclear, the licensed operator of Southern Company's three nuclear generating plants; SouthernLINC Wireless, a communications network with about 300,000 subscribers; and Southern Telecom, a fiber optic wholesaler in the Southeast.

Southern Company is also a member of the Utility Air Regulatory Group (UARG). Southern Company herby endorses and incorporates by reference UARG's comments in this matter. Importantly, Southern Company also endorses the positions taken by UARG and aligned petitioners in various litigated matters regarding the regulation of GHGs under the Clean Air Act (CAA), and these comments are not intended to conflict with the resolution of those legal issues as advocated by UARG and aligned petitioners in those matters.

I. Proposed Settlement Agreement Regarding a Rulemaking on Proposed CAA Section 111 Standards for GHG Emissions from Electric Utility Generating Units

The proposed settlement agreement between the State of New York, et al. and the EPA, notice of which EPA provided in the Federal Register on December 30, 2010, requires EPA to issue a proposed rule establishing NSPS for GHG emissions from new and modified electric utility generating units (EGUs) by July 26, 2011. Additionally, by July 26, 2011, EPA would need to issue a proposed rule that would set guidelines for states to develop GHG emission standards for existing EGUs. This deadline is a meager 4 months from now. Under the proposed settlement agreement, EPA would also be obligated to finalize these rules by May 26, 2012, a short 10 months after proposal.

Southern Company is deeply concerned about the aggressive rulemaking schedule contained in the proposed settlement agreement and urges EPA to withdraw or withhold its consent to the proposed settlement agreement in order to permit a more reasoned and thorough review of these important issues.

EPA needs to look no further than the recent issues surrounding the regulation of hazardous air pollutant emissions from industrial boilers to determine that binding itself to short and inflexible timelines through settlement agreements and consent decrees does not bode well for achieving an efficient and reasoned rulemaking. Due to stringent deadlines associated with the industrial boiler rulemaking, EPA requested a 15 month rulemaking extension by the U.S. District Court for the District of Columbia, to enable EPA to re-propose and finalize the rule. EPA felt this extension was necessary in order "to develop workable rules that can be implemented effectively and that can withstand judicial review."[1] The U.S. District Court for the District of Columbia denied EPA's request for an extension and only provided EPA with an additional month to finalize the industrial boiler rule. On February 21, 2011 EPA finalized the industrial boiler rule and due to the District Court's denial of the 15 month extension had to immediately announce that: "[t]he Agency is in the process of developing a proposed reconsideration notice that identifies the specific elements of the rules for which we [EPA] believe further comment is appropriate and any provisions that we [EPA] propose to modify after fully evaluating the data and comments already received."[2] Given that developing NSPS for GHG emissions from new and modified EGUs and guidelines for states to develop GHG emission standards for existing EGUs is a complicated and controversial issue that has never been done for any source category and given the lack of flexibility EPA likely will be faced with if it consents to the proposed settlement agreement, EPA should withdraw or withhold its consent. Implementing the aggressive rulemaking timeline found in the proposed settlement agreement will not provide EPA the time necessary to adequately develop, collect, and review information, such as public comments, vital to the rulemaking process.

Given more time, EPA would be in a position to release an advanced notice of proposed rulemaking (ANPR) and complete a thorough and reasoned regulatory impact assessment of all aspects of the rulemaking, including the guidelines for states to develop GHG emission standards for existing EGUs. Additional time would also provide EPA with a better opportunity to consider how the promulgation of NSPS for GHG emissions fits within EPA's overall regulatory scheme. The interaction between NSPS for GHG emissions and the numerous other regulatory initiatives that will impact electric generators needs consideration. Impacts of EPA's current regulatory agenda on the ability of the currently affected fossil generator fleet to both comply with new environmental rules, that tend to negatively affect efficiency, and any GHG rules that would expect improvements in efficiencies, needs detailing. Widespread impacts are expected to result from EPA's cumulative air, coal combustion byproducts, water, and GHG regulatory initiatives. As part of its analysis EPA needs to complete a comprehensive regulatory impact assessment in order to develop a reasoned rulemaking.

II. GHG NSPS Should Not Include CCS Because It Is Not Adequately Demonstrated

[1] Sierra Club v. Jackson. Case No. 1:01-cv-01537-PLF, Document 136-2, Filed 12.7.2010.

[2] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers; Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units: Notice of Reconsideration, 2.21.2011.

Any performance standard established by EPA must be based on technologies that are adequately demonstrated. Currently, there are no GHG control technologies demonstrated at commercial scale. A standard cannot be set based on a technology that may be adequately demonstrated at some future time. Carbon capture and storage (CCS) is an example of a technology that cannot be used to set a GHG NSPS. CCS is not an adequately demonstrated carbon dioxide (CO_2) control technology for EGUs. Each piece of the CCS process – capture, transport, and storage – has been demonstrated at some capacity, however, CO_2 capture, transport, and storage have not been integrated at commercial scale on an EGU. The integration of these processes on an EGU could result in operational issues and other unknowns, which need to be investigated and determined through additional research. Southern Company bases this conclusion on its industry leading research activities associated with CCS technologies.

In Session 1 of EPA's listening sessions on GHG standards for fossil fuel fired power plants and petroleum refineries, the EPA Assistant Administrator for Air and Radiation Regina McCarthy noted that: NSPS is not a technology forcing standard and is not designed as a dramatic tool. The Assistant Administrator also stated that: it is very clear that CCS is not commercially available and that there are costs issues regarding the technology. Southern Company agrees with and supports this statement. For these reasons and other reasons included in these comments, any performance standard established by EPA should be based on technologies that are adequately demonstrated and not on technologies that need further development, such as CCS.

Past NSPS revisions for NOx and SO_2 prove that EPA's precedent for establishing a particular technology as adequately demonstrated requires a significant level of full scale EGU installations. In 1998, EPA revised the performance standards for NOx emissions for both utility and industrial steam generating units to reflect the performance of the best demonstrated technology. EPA determined that flue gas treatment technologies, particularly selective catalytic reduction (SCR), represented the best demonstrated technology for NOx emissions reduction. EPA based this determination on the presence of "at least 212 worldwide SCR installations on coal-fired units, which cover different types of boilers subjected to varying operating conditions and firing a variety of coals." EPA also noted that "[p]lants in Europe have been continuously using SCR for over 10 years" (63 FR 49442 - 49455).

Additionally, in 1979 EPA revised the 1971 NSPS for SO_2 for coal-fired electric generating plants. The 1979 revision retained the 1971 performance standard but added a requirement for a 70 to 90 percent reduction in emissions, depending on the sulfur content of the coal. At the time, this requirement could be met only through use of a flue gas desulfurization (FGD) system. Prior to the 1979 revised NSPS for SO_2 and between 1973 and 1978, FGDs were installed on about 50 units in the U.S. representing about 20 GWs.[3]

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[3] Parker, Larry, Peter Folger, and Deborah D. Stine. "Capturing CO_2 from Coal-Fired Power Plants: Challenges for a Comprehensive Strategy." CRS Report for Congress – Order Code RL34621. August 15, 2008.

Integrated CCS technologies are nowhere near the deployment level of SCRs and FGDs when EPA determined those technologies as being an adequately demonstrated technology for NOx and SO_2 NSPS. Thus, CCS should not be included in EPA's GHG NSPS.

III. Southern Company is a Leader in Carbon Capture and Storage Technology Research

Southern Company is a leading researcher in CCS technologies for EGUs. According to the Interagency Task Force on CCS, "CCS is a three-step process that includes the capture and compression of CO_2 from EGUs or industrial sources; transport of the captured CO_2 (usually in pipelines); and storage of that CO_2 in geologic formations, such as deep saline formations, oil and gas reservoirs, and unmineable coal seams."[4] Southern Company's research involves each step of the CCS process individually and the integration of all three steps. As noted above, CCS technologies have not been integrated at commercial scale on an EGU. A description of Southern Company's CCS research is below. These descriptions highlight the depth to which Southern Company is researching CCS technologies, and they uncover the vital need for additional research and technological development to move the CCS technology from the demonstration/pilot scale to the commercial scale for EGUs.

Southern Company's research projects include the National Carbon Capture Center (NCCC) which is a focal point of the U.S. Department of Energy's (DOE) efforts to develop advanced technologies to reduce GHG emissions from coal-based power generation. It is a neutral test site focused on conducting research and development to advance emerging CO_2 control technologies for effective integration into commercial coal-fired power plants, including integrated gasification combined cycle plants and conventional pulverized coal plants. It will test and evaluate CO_2 control technologies including CO_2 capture solvents, mass-transfer devices, low cost water-gas shift reactors, scaled-up membrane technologies, and improved means of CO_2 compression. It is managed and operated by Southern Company and located at the Power Systems Development Facility in Wilsonville, Alabama. In addition to DOE and Southern Company, partners include American Electric Power, the National Energy Technology Lab, EPRI, Luminant, Peabody Energy, Arch Coal Inc., and Rio Tinto.

Southern Company also participated in a pilot CO_2 injection project undertaken at Mississippi Power's Plant Daniel by the Southeast Regional Carbon Sequestration Partnership (SECARB). This project involved drilling an injection well and an observation well into the Tuscaloosa Formation in South Mississippi. Approximately 3,000 tons of CO_2 were injected into a saline formation approximately 8,500 ft underground. The injection was completed in the fall of 2008 and monitoring completed in 2010. Another one of Southern Company's research projects is a pilot injection project in the Black Warrior Basin coal seam which involves injecting 240 tons of CO_2 into coal seams at depths ranging from 940 feet to 1,800 feet. The project began in 2009 with the injection operations finalized in 2010. Monitoring will continue for several years to evaluate the methane recovery potential from the injection.

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[4] "Report in the Interagency Task Force on Carbon Capture and Storage," August 2010.

Southern Company is also researching the geologic storage capacity and injectivity of certain sites and analyzing seal integrity and containment using laboratory analysis and reservoir simulation. Development of protocols for assessment of seal layer integrity and analysis of cap rock samples from geologic formulations under consideration for sequestration of CO_2 is also being researched.

Additionally, Southern Company, in conjunction with EPRI, is researching the impact CO_2 has on shallow groundwater. The project will evaluate the potential geochemical impacts of CO_2 in drinking water aquifers. The project will take place at Mississippi Power's Plant Daniel. Site characterization has been performed, and the test is scheduled for 2011.

Southern Company's affiliate Mississippi Power plans to construct Plant Ratcliffe, an air-blown Integrated Gasification Combined Cycle demonstration project that will allow for pre-combustion capture and storage of 65 percent of the demonstration project's CO_2 emissions. Plant Ratcliffe is a DOE Clean Coal Power Initiative demonstration project. The demonstration project will utilize a coal-based transport gasifier which has a fuel-flexible design projected to have higher efficiency and lower capital and operating costs than the currently available oxygen-blown entrained-flow gasifiers. The demonstration project will be built in Kemper County, Mississippi and generate electricity using Mississippi lignite.

Southern Company is also constructing a 25 MW slip stream amine post-combustion capture demonstration plant at Alabama Power's Plant Barry. Construction activities are scheduled for completion in 2011 with plant start-up to take place shortly thereafter. The project will provide CO_2 for the DOE regional sequestration partnership SECARB phase 3 large volume sequestration demonstration project. The SECARB project includes drilling two injection wells and two observation wells into the Paluxy saline formation located geologically above the Citronelle Oil Field in South Alabama. The project will inject 100,000-150,000 tons of CO_2 per year for up to four years with monitoring for an additional four years. The project will also construct and operate a twelve mile pipeline that will connect Plant Barry to the injection site. The project will evaluate effective monitoring and verification protocols for geologic sequestration, address regulatory and permitting issues, and cultivate public education and outreach internally and externally. It will also be one of the first projects in the world to study, at demonstration scale, the integration of CO_2 capture operations at a coal-fired power plant with pipeline transportation and saline reservoir injection.

Based on Southern Company's extensive research, CCS is not an adequately demonstrated CO_2 control technology for commercial scale EGUs. Each piece of the CCS process – capture, transport, and storage – has been demonstrated at some capacity, however, CO_2 capture, transport, and storage have not been integrated at commercial scale on an EGU. The integration of these processes on an EGU could result in operational issues and other unknowns. Additionally, there are unresolved legal issues associated with CCS that need to be addressed before CCS can be widely deployed. These issues include pore-space ownership and long-term liability. Some states have enacted laws governing these issues, but they vary. This is a problem for projects that operate in states without these laws and for projects that cover multiple states.

Also, CCS is different from other control technologies, because it may involve a third party. For example, if CO_2 storage is going to be done through enhanced oil recovery (EOR), more than likely, the power generator will have to enter into a contract with a third party to take the CO_2 and responsibility for demonstrating storage. If there are problems with the contract or if the third party dissolves after some time, the power generator will be at risk unless it can find someone else to take its CO_2.

Once again, these descriptions highlight Southern Company's efforts to research CCS technologies, and they demonstrate the vital need for additional research and technological development to move the CCS technology from the demonstration/pilot scale to the commercial scale for EGUs.

IV. Guidelines for States to Develop GHG Emission Performance Standards for Existing EGUs

EPA should provide states with as much flexibility as possible in establishing guidelines for developing GHG performance standards for existing EGUs. In developing guidance, EPA should:

- Recognize differences in different fuels and combustion technologies;
- Recognize differences in unit types, sizes, and system demands;
- Recognize natural degradation in efficiency over time in all units;
- Recognize the trade-offs between a) decreased unit efficiencies due to traditional pollutant controls and the effort to incorporate renewable energy sources to a utility's portfolio and b) the higher unit efficiencies that EPA may seek in the effort to lower GHG emissions;
- Consider fleet-wide approaches to achieving performance standards;
- Address the possibility that GHG efficiency projects can potentially trigger pre-construction permitting requirements under new source review (NSR) and prevention of significant deterioration (PSD) programs.

V. Reliability and Affordability Crisis for Electricity in the U.S.

EPA is developing a number of regulatory initiatives that will significantly impact the electric utility industry. These potential regulatory initiatives include the proposed settlement agreement's directive to establish NSPS for GHG emissions from new and modified EGUs and guidelines for states to develop GHG emission performance standards for existing EGUs. A number of studies have been released detailing the impacts these regulatory initiatives may have on the reliability and affordability of U.S. electricity. Each study's scope is different. Some studies maintain a narrow focus (i.e., analyzing regulatory initiatives individually or only analyzing the combined impacts of a couple initiatives) while others take a more comprehensive approach (i.e., analyzing the cumulative impacts of the majority of EPA's regulatory initiatives).

The Edison Electric Institute's (EEI) analysis prepared by ICF International, titled "Potential Impacts of Environmental Regulation in the U.S. Generation Fleet," is the most comprehensive analysis of EPA's regulatory initiatives to date. ICF International modeled the combined impacts of EPA's potential air, coal combustion byproducts, water, and GHG regulations.[5] The study is the culmination of a year-long effort and represents a collaborative attempt to synthesize alternative approaches suggested by EEI's membership for the selection of modeling inputs. These inputs include expected natural gas prices and the costs for new technology; scenarios about the potential regulations themselves (i.e., what regulation will apply, and the timing and stringency of those regulations); and sensitivities for modeling, including variation in natural gas prices, technology choices, and regulatory requirements. The report summarizes the potential impact for unit retirements, capacity additions, pollution control installations, and capital expenditures at the national and regional levels under a variety of potential scenarios.

The EEI analysis shows that when the combined impact of EPA's regulatory initiatives are analyzed, over 150 GWs of coal, half of the U.S. coal fleet, are at risk of being unavailable in 2015 for needed energy and required reliability due to insufficient time to install controls or replacement generation. Under this analysis, nearly 80 GWs of coal would retire by 2015 and the remaining coal would be subject to an unachievable retrofit schedule. These retirements and retrofits create the need to spend about $300 billion in the next five years, over two-thirds of which is for replacement generation. These circumstances lead to generation shortages and a rapid run-up in prices creating a reliability and affordability crisis. Careful consideration needs to be given to these impacts if EPA decides to proceed in developing NSPS for GHG emissions from new and modified EGUs and guidelines for states to develop GHG emission performance standards for existing EGUs.

VI. Conclusion

As discussed above, it is clear that EPA does not have sufficient time to develop an efficient and reasoned proposal by July 26, 2011 on very complex issues that could have far reaching and long-term impacts on how entities generate electricity in the U.S. EPA needs to pursue a more reasoned and thorough rulemaking approach that pursuant to a rulemaking schedule will allow EPA to appropriately consider the complexities of establishing an NSPS for GHG emissions from EGUs. At a minimum, EPA should allow time to conduct an ANPR to assist in gathering the necessary data needed to develop a proposal for such a rulemaking. An ANPR would also allow EPA more time to comply with Executive Order No. 13563 Improving Regulation and Regulatory

[5] Air regulations include: EGU MACT, Air Quality Standards (Clean Air Transport Rule, Ozone, Particulates, SO_2, NO_2) and Regional Haze. Coal Combustion Residuals include consideration of the currently proposed rules. Water includes consideration for the water intake structure (316(b)) regulations being developed. GHGs include consideration for the regulatory requirements currently under development and the uncertainty of the future of legislative requirements.

Review, other obligations under the Regulatory Flexibility Act, and to better align interactions with other pending rulemakings affecting EGUs.

Further, any performance standard established by EPA must be based on technologies that are adequately demonstrated. A standard cannot be set based on a technology that may be adequately demonstrated at some future time. CCS is an example of a technology that cannot be used to set a GHG NSPS. CCS is not an adequately demonstrated CO_2 control technology for EGUs. Southern Company bases this conclusion on its industry leading research activities associated with CCS technologies. EPA must also consider the impact their current regulatory agenda has on the ability of the currently affected fossil generator fleet to both comply with new environmental rules that tend to negatively affect efficiency and any GHG rules that would expect improvement in efficiencies. Additionally, when establishing guidelines for developing GHG performance standards for existing EGUs, EPA should provide states with as much flexibility as possible. Finally, EPA should consider and minimize the cumulative effects of EPA's regulatory initiatives affecting EGUs. If appropriate consideration is not given to the cumulative impacts of these initiatives, generation shortages and a rapid run-up in prices creating a reliability and affordability crisis are likely to result.