EPA's Responses to Public Comments on EPA's *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units*
December 2011

Volume 2 of 2

Comments, letters, and transcripts of the public hearings are also available electronically through h*ttp://www.regulations.gov* by searching Docket ID *EPA-HQ-OAR-2009-0234.*

FOREWORD

This document provides the EPA's responses to public comments on the EPA's Proposed *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*. The EPA published a Notice of Proposed Rulemaking in the Federal Register on May 3, 2011, at 76 FR 24976. The EPA received comments on this proposed rule via mail, e-mail, facsimile, and at three public hearings held in Chicago, Illinois; Atlanta, Georgia; and Philadelphia, Pennsylvania, in May 2011. Copies of all comments submitted and transcripts for the public hearings are available at the EPA Docket Center Public Reading Room. Comments, letters, and transcripts of the public hearings are also available electronically through *http://www.regulations.gov* by searching Docket IDs *EPA-HQ-OAR-2009-0234* (NESHAP action) and *EPA-HQ-OAR-2011-0044* (NSPS action).

This document contains responses to comments on the NESHAP only; responses to comments on the NSPS action are in a separate Response to Comments document. Due to the size and scope of this rulemaking, the EPA summarized a limited amount of major comments in the preamble of the final rule. This document contains a summary of all significant comments provided by each commenter extracted from the original letter or public hearing transcript.

Appendix A of this document provides a list of public hearing speakers and their affiliation. Appendix B of this document provides a list of commenters and their affiliation along with the associated document control number (DCN). For each comment, the DCN is provided along with the comment summary. For purposes of this document, the text within the comment summaries was provided by the commenter(s) and represents their opinion(s), regardless of whether the summary specifically indicates that the statement is from a commenter(s) (e.g., "The commenter states" or "The commenters assert"). The comment summaries do not represent the EPA's opinion unless the response to the comment specifically agrees with all or a portion of the comment. In some cases the same comment was submitted by two or more commenters through submittal of a form letter prepared by an organization, by the commenter incorporating by reference the comments in another comment letter, or by the commenter providing identical or similar language independently. Rather than repeat these comment excerpts for each commenter, the EPA has listed the comment excerpt only once and provided a list of all the commenters who submitted the same form letter or otherwise incorporated the comments by reference in Tables 9A-1 through 9A-21 and 9B-1 through 9B-5 of section 9 of this document and Table 10-1 of section 10 of this document, respectively.

Several of the EPA's responses to comments are provided immediately following each comment summary. However, in instances where several commenters raised similar or related issues, the EPA has grouped these comments together and provided a single response after the last comment summary in the group. In some cases, the EPA provided responses to specific comments or groups of similar comments in the preamble to the final rulemaking. Rather than repeating those responses in this document, the EPA has referenced the preamble or the appropriate technical support document for a description of the analysis included in the final rule.

As both the NESHAP and NSPS actions were included in the same proposal package, many commenters submitted comments to this rulemaking docket that were specific to the NSPS action. Some commenters submitted a single DCN with comments on both rules, while others submitted a separate DCN specific to each action. Many commenters submitted identical comments to both dockets. In order to reduce duplicative comments, we have removed from this document comments associated with the NSPS action. For this reason, the EPA encourages the public to read the Response to Comment document prepared for the NSPS action.

TABLE OF CONTENTS

CHAPTER 5: COMPLIANCE WITH TESTING/MONITORING/RECORDKEEPING AND REPORTING

5A01 - Testing/Monitoring: Stack Test Methods

Commenters: 17174, 17191, 17402, 17621, 17623, 17675, 17681, 17696, 17716, 17725, 17729, 17730, 17731, 17747, 17754, 17758, 17767, 17770, 17775, 17790, 17795, 17800, 17807, 17808, 17820, 17821, 17868, 17877, 17878, 17880, 17881, 17975, 18014, 18015, 18021, 18025, 18034, 18428, 18498, 18539, 18935, 18963, 19033, 19536, 19537, 19538, 18932, 18023

1. Comments related to alternative compliance test methods.

Comment 1: Commenter 17775 states that the EPA should allow use of Method 5B and 29 to demonstrate compliance with the PM limits under the stack testing option. Rather, the commenter asserts, the EPA proposes to allow use of Methods 5, 5D (required for positive pressure FFs), or 17 (Proposal Table 5). The commenter states that sources performing calibrations of PM CEMS under Performance Specification (PS) 11, on the other hand, are also allowed the option of using Method 5B - Determination of Nonsulfuric Acid Particulate Matter Emissions from Stationary Sources. The commenter states that Method 5B was specifically developed to determine primary filterable PM emissions from sources with wet scrubbers and is routinely allowed for stack testing under federal regulations. (40 CFR part 60, subparts D (section 60.46(b)), Da (section 60.50Da(e)(1)), Db (section 60.46b(d)(2)), Dc (section 60.45c(a)(2)) and part 63, subparts QQQ (section 63.1450(b), UUU (section 63.1579 and tables).) The commenter asserts that the EPA should allow use of Method 5B or explain why the method is not appropriate for demonstrating compliance with the proposed limits. The commenter asserts that although the agency's specification of a filter temperature for Method 5 (320° F + 25) achieves some of Method 5B's objective, there is no basis for not allowing sources to use a promulgated test method specifically designed for that purpose. According to the commenter, prohibiting use of Method 5B could prevent some sources from using tests under subpart UUUUU to meet other testing requirements without obtaining approval for use of a higher Method 5 filter temperature in lieu of using Method 5B. Moreover, according to the commenter, evaluation of filterable PM data from the agency's 2010 ICR database reveal an inconsistency between Method 5 and Method 29 results. The commenter attaches a discussion of and findings on this issue. To the extent the EPA proposes or promulgates a PM limit that is based in any way on filterable PM results from Method 29, commenter asserts that the EPA must provide EGUs the option to use Method 29 for any PM testing.

Comment 2: Multiple commenters (17681, 17716, 17725, 17767, 17790, 17795, 17800, 18014) request that the final rule include the following reference methods in Table 5:

1. EPA Method 2H,
2. Conditional Test Method 41 (wall effects adjustment for flow),
3. EPA Method 26A (HCl - option for dry stacks),
4. EPA Method 320 (HCl – FTIR option),
5. EPA Method 5B,
6. EPA Method 17 (total, filterable PM), and
7. The table should indicate that Method 2 (or equivalent) need only be used if necessary to calculate output-based emissions.

Response to Comments 1 and 2: The final rule has been amended to allow the use of EPA Methods 2H, 26A and 320 and clarify the requirement of Method 2 (or equivalent) only as necessitated by the calculation of the emission limit. The basis for the filterable PM emissions limit in the final rule is EPA Method 5 with a filter temperature of 320° F and sample desiccation at temperatures up to 220º F for up to 3 hours. While Method 5B also specifies a filter temperature of 320º F, Method 5B includes an additional extended (6 hour) heating of the filter in the laboratory to remove particulate matter that would volatilize at 320º F including condensed sulfuric acid. This additional analytical step renders the method unusable for determining compliance with a limit based on Method 5 procedures. As for using Method 17, we did not cite the method in the rule but would entertain a request for site-specific alternative method approval to use Mehtod 17 in lieu of Method 5. A condition of approval is that the stack gas temperature at the sampling location remains no greater than 320º F during the performance testing.

Comment 3: Several commenters (17767, 17790, 17795, 17800, 17821) state that proposed use of Method 5 rather than Method 5B in wet stacks is inconsistent with NSPS (e.g., section 60.46(b), section 60.50Da(e)(1), section 60.46b(d)(2), and section 60.45c(a)(2)) and inconsistent with part 63(e.g., section 63.1450(b) and section 63.1579), and the commenters request that the final rule specify the option to use Method 5B in wet stacks for compliance tests and PM CEM certifications consistent with PS-11. Commenter17795 acknowledges that the filter temperatures listed in Table 5 are consistent with Method 5B but points out that filter desiccation temperatures per the proposal would occur at M5 temperatures (220 °F). Commenter 17795 states that absence of Method 5B from the proposal creates a problem complying with section 3.20 of PS-11, which defines "reference method" as the method defined in the applicable regulation, but the method listed in proposed Table 5 is a hybrid method. Commenter 17795 states that inclusion of Method 5B is critical to certification of PM CEMS because all wet particulate monitors use some type of heated cyclone to vaporize water droplets before analyzing the gas sample, and the temperature of these cyclones is set to be consistent with the reference method filter temperature. However, according to this commenter, in order to obtain a final filter weight the reference method filters must be desiccated, to a constant weight, and proposed Table 5 specifies Method 5, which by default would require filter desiccation at 220 °F. According to this commenter, since the PM CEMS sampling process occurs at temperatures above the acid dew point, Method 5B should be followed to allow filters to be desiccated at the same temperatures as sample collection to minimize inaccuracies for wet PM CEMS correlations. Commenters (17795, 17800) also believe that making the MACT standard consistent with the NSPS program and SIP programs will allow the use of a single stack test to satisfy multiple regulatory requirements and save time, resources, and costs. Commenter 17725 recommends that the EPA also allow 40 CFR Part 60 Method 2H-Determination of Stack Gas Velocity Taking into Account Velocity Decay Near the Stack Wall as a valid method for all pollutant types listed in Table 5 to subpart UUUUU of part 63 performance stack testing requirements. The commenter notes that they utilize Methods 2, 2F, 2G, and 2H for annual volumetric flow monitoring as required across the fleet.

Response to Comment 3: The final rule does not require the certification of the PM CEMS by PS-11. However, in the event a source wants to be able to use a PM CEMS as a direct method of determining compliance with the filterable PM emission limits in the final rule, the final rule allows for this option. Please see the final rule preamble for further discussion.

Comment 4: Commenter 17775 requests that the agency clarify that use of certain methods (Methods 2, 2F, 2G, and 4) are optional because proposed Table 5 lists Methods 2, 2F or 2G as the required methods to determine the velocity and volumetric flow rate of the stack gas when testing for PM, HCl, and Hg, and lists Method 4 to determine moisture content for all pollutants, but in some cases, use of these methods may not be necessary, or reasonable, because all of the methods specified in Table 5 for concentrations of those emissions also provide measurements of velocity and flow. Likewise, according to the commenter, the methods used to determine pollutant concentrations (e.g., Methods 5, 23, and

26A) also determine stack moisture. The commenter states that the agency should make use of those methods optional and allow the EGU to determine which method is more appropriate for the specific test.

Response to Comment 4: The final rule has been amended to clarify that only methodology or equations required for the specific emission limit will be required.

Comment 5: Commenter 17808 recommends measures be incorporated in the final rule to avoid running a unit simply to conduct a stack test similar to the approach used in part 75 for defining an operating quarter and a unit operating hour. Specifically, the commenter recommends incorporation of the provisions of 40 CFR 72.2 defining a "QA operating quarter" as "a calendar quarter in which there are at least 168 unit operating hours (as defined in this section) or, for a common stack or bypass stack, a calendar quarter in which there are at least 168 stack operating hours (as defined in this section)." According to this commenter, a unit operating hour would be defined as a clock hour during which a unit combusts any regulated fuel, either for part of the hour or for the entire hour. The commenter recommends that these definitions apply specifically to the regulated fuels under the EGU MACT rule (e.g., coal and liquid oil), because by requiring a minimum level of operation to trigger stack testing requirements, no unit will be operated simply for the sake of testing.

Commenter 17808 recommends an additional, alternative method for demonstrating continuous compliance for Hg when a unit qualifies for LEE status. As an alternative to conducting monthly fuel tests, the commenter proposes that owners/operators of a LEE unit have the option to conduct an annual Method 30B performance test to demonstrate that its emissions are less than 10 percent of its applicable Hg emissions limit or less than 22.0 pounds per year. If a LEE unit exceeds LEE limits, the commenter proposes that the unit revert back to more frequent performance tests (e.g., quarterly, as recommended above). Under this commenter's proposal, in the subsequent year, if the unit can, again, demonstrate LEE status through reduced utilization or a lower emission rate, it would return to annual stack tests under the LEE provisions. The commenter recommends this alternative, annual stack testing instead of monthly fuel testing, to balance the need for accurate emissions data with reduced compliance costs for those units emitting at a fraction of the proposed standards. Also, in order to avoid having companies run units simply to conduct stack testing, the commenter proposes that LEE units have the flexibility to schedule their annual performance tests at any time during a 12-month cycle because some of these LEEs may be smaller units with low capacity factors and may go several months without operating. The commenter believes that allowing flexibility in scheduling stack tests will avoid unnecessary HAP emissions and reduce costs for these units operating well below the proposed standard and believes this compliance option would allow companies to align testing under this rule with existing state testing requirements.

Response to Comment 5: The EPA agrees with the comments. The final rule has been amended to waive testing requirements in a quarter when the unit operates for less than 168 hours, but the source must under any circumstances test at least once per year.

Comment 6: Commenter 17747 states that they would also like to see the Method 29 monitoring options (Method 29 testing every 2 months or every month depending on PM control) retained. The commenter believes that this gives plant operators additional control options and flexibility in achieving emissions limits.

Response to Comment 6: The final rule has been amended to allow compliance with the non-Hg metals limit with quarterly Method 29 testing.

2. Comments related to testing period (clarification etc.).

Comment 7: Commenter 17868 states that the final rule should clarify the required testing period in proposed section 63.10005(k) which specifies 28 to 30 days, but proposed Table 5 specifies 30 days.

Response to Comment 7: The EPA has clarified this issue in the final rule. The required testing period is 30 days**.**

Comment 8: Commenter 18539 states that it is not clear in the proposal whether the EPA intends to require one performance test every 5 years for all surrogates. For example, asserts the commenter, proposed section 63.10005(d)(4) states that initial compliance for coal-fired units with FGD technology and SO_2 CEMs is determined using the average hourly SO_2 concentrations during the first 30-day operating period, and section 63.10005(d)(5) states the same for PM CEMs. However, according to the commenter, pages 25051 and 25051 of the preamble and section 63.10005(a) indicate that PM, metals, SO_2, and HCl compliance tests are required initially and every 5 years. According to the commenter, section 63.10005(a) states that "[I]f you use a continuous monitoring system that measures a surrogate for a pollutant (e.g., an SO_2 monitor), you must perform initial emission testing during the same compliance test period and under the same process (e.g., fuel) and control device operating condition of the pollutant and surrogate, in addition to conducting the initial 30-day performance test." Additionally, the commenter states, section 63.10006(a) and (b) state that PM and non-Hg metal HAP, and SO_2 and HCl emissions testing, respectively, is required at least every 5 years. The commenter requests that the EPA clarify the intent of the stack testing requirements and give appropriate time to comment on this requirement.

Response to Comment 8: The final rule has been amended to only require testing and/or monitoring for the specific emission standard with which the source complies (either the direct emission limit, such as HCl, or the alternate equivalent standard, such as SO_2).

Comment 9: Commenter 17775 requests that the agency clarify the required testing period because proposed section 63.10005(k) refers to a 28-30 operating day performance test and proposed Table 2 similarly requires "LEE testing for 28-30 days." However, according to the commenter, proposed Table 5 requires conversion of emission concentrations to "30 boiler operating day rolling average lb per MMBtu emission rates or lb/MWh emission rates" (proposed Table 5 (4.f.)). According to the commenter, if the EPA intends to allow use of 28 days of sorbent trap data (i.e., two 14-day sorbent traps) to determine the "average Hg concentration" for the performance test, the EPA should make clear in Table 5 that the values in Table 5 can be derived from 28 days of data.

Response to Comment 9: The final rule has clarified this issue. The required testing period is 30 days.

3. Comments related to operating parameters and fuel limits set during testing.

Comment 10: Commenter 17775 requests clarifications regarding the proposal's stack testing options for HAP metals because it is not clear to the commenter whether the agency intended the operating parameters and fuel input limits in proposed section 63.10011(b) to apply, because on its face, the requirements of section 63.10011(b) appear to apply to all EGUs, regardless of the compliance option. However, according to the commenter, that result is not consistent with the agency's expressed intention. For example, the commenter asserts, in the preamble the EPA says that such operating parameters do not apply and cites 76 FR 25,029/3 ("*Except for liquid oil-fired units,* . . . we are proposing that you monitor during initial performance testing specified operating parameters) (emphasis added). However, the commenter states, similar to LEEs, the EPA also suggests that liquid oil-fired units must meet maximum fuel input limits as an operating limit (citing 76 FR 25,030/2). According to the commenter, the EPA must make clear in section 63.10011(b) what operating limits apply and issue a proposal explaining why. The commenter states that if the maximum fuel input limits in section 63.10011(b) apply to liquid oil-fired EGUs opting to demonstrate compliance using stack testing, the EPA should make clear that EGUs combusting a single fuel type are not required to make any determination regarding that fuel under section 63.10011(b)(2)(i) and (3)(i) (requiring determination that the fuel type or mixture has the highest content of Hg and of non-Hg HAP metal) and that EGUs using supplemental fuels qualify as single fuel EGUs. The commenter states that although the EPA has attempted to address that issue for liquid oil-fired EGUs in section 63.10005(c)(4) and section 63.10011(c)(1), those provisions apply only to liquid oil-fired EGUs complying through fuel analysis.

Comment 11: Commenter 18023 states that the agency must clarify that operating limits and fuel limits do not apply to sources using CEMS for compliance because the commenter assumes that the purpose of the operating limits is to demonstrate compliance between regularly scheduled performance tests at units that are not otherwise continuously monitoring compliance; however, the proposed rule is not clear on this point. The agency should therefore specify that the operating limits (including the operating load limit) and fuel limits apply only to units using stack tests to comply.

Comment 12: Commenter 17775 states that the final rule must clarify the operating limit requirements for control devices and the single fuel EGU requirements for establishing a maximum fuel input for chlorine under section 63.10011(b)(1)(i).

Comment 13: Commenter 17878 states that for units not equipped with CEMS it is appropriate to have an alternative approach to assure compliance for the periods between stack tests. The EPA proposes to set enforceable operating limits based on control device parameters measured during performance testing creates what is effectively a second and more stringent standard. According to the commenter unit operators will utilize control equipment that is designed to provide a margin of compliance that provides flexibility for the source to account for small variations in control equipment performance and fuel characteristics. The result will be "over-compliance" during a periodic stack test, and this is normal. If operating conditions reflecting this stack test period are then used as a measure of ongoing compliance, then those expected variations, which do not exceed an emission limit, would become violations.

Comment 14: Commenter 17868 states that the EPA should re-evaluate the proposed operating parameter requirements.

Response to Comments 10 - 14: The final rule has removed the requirements for operating and fuel limits, except where a source: (1) opts to use a PM CPMS to monitor compliance; or (2) for a liquid oil-fired unit, adopts a source-specific monitoring plan to collect, record, and report on appropriate operational parameters in addition to conducting quarterly performance tests. In addition, the EPA notes that the final rule allows a source to monitor fuel moisture data to demonstrate compliance with the HCl and HF standards for liquid oil-fired units (fuel moisture must be no greater than 1.0%). The details of these options are discussed in the preamble to the final rule and elsewhere in this response to comment document. There are no operating parameter requirements in situations where a source determines compliance with an emission limit using a CEMS.

4. Comment related to use of short term stack test and fuel samples to set 30-day standards.

Comment 15: Commenter 17402 states that the EPA should not penalize facilities with low emissions by setting both fuel content and operating limits based on average performance during stack tests because this methodology effectively sets lower standards. Instead, according to the commenter, the EPA should set fuel content limits based on the source's contaminant removal effectiveness, so that a source can use a range of fuels as long as the standard is met. Commenter 17729 is an affected source operator who discusses stack test results for non-Hg metals and total PM at a unit that will be subject to the proposed MACT standards. Commenter 17720 states that the stack test data collected in 2010 in response to the EGU MACT ICR reflected compliance with the proposed standards during the 4-hour steady state tests, but this source operator states that such steady state tests do not indicate if continuous compliance is achievable at this source. Commenter 17623 states that the proposed limits for PM do not allow for variability because they are based on the particular conditions during one stack test for CPM, and the commenter believes that when setting a MACT standard, variability must be taken into account. The commenter adds that since each stack test is time-consuming and costly, the EPA cannot expect facilities to feasibly perform numerous stack tests.

Response to Comment 15: The final rule has removed the requirements for operating and fuel limits with the exceptions noted in Response to Comments 10-14, above.

5. Comments related to concerns about use of Method 202.

Comment 16: Commenter 18014 states that despite Method 202 being revised to include a nitrogen purge and an initial dry impinger (which is quickly wetted with condensation from the flue gas) to reduce these artifacts, the remaining SO_2-related artifacts can be significant at low levels. According to the commenter, because of the bias, extending the run time does not necessarily improve the accuracy or detection limit since it simply provides more time for the artifacts to form and, thus, tends to defeat the purpose of adding the purge/dry impinger. According to the commenter, recent studies have shown the SO_2-related artifact formation to be particularly acute if there is any NH_3 in the flue gas (e.g., slip from an SCR for NO_X control), which again is not related to primary particulate and certainly not related to metal HAP in any way.

Comment 17: Commenter 17402 expresses concerns that condensable PM reference Method 202 is unproven and variable and should be improved, because the commenter has reviewed many reports on Method 202 and OTM 28 and has carried out Method 202 testing programs. The commenter asserts that even with the recent improvements to Method 202 there are concerns about condensable PM formation and creation of pseudo particulates. The commenter references recently completed Method 202 stacks tests on a number of units using the same coal, and observations that the condensable PM fraction ranged from 7% to 75%. This commenter relays plans to install Trona FGD controls to reduce HCl and to further reduce condensable PM but expresses concerns that Method 202 may not properly quantify actual reductions. Commenter 17402 also relays plans to commission nine SNCR systems and associated concerns about ammonia slip reactions with dissolved SO_2. Commenter 17402 encourages the EPA to continue research & development (R&D) on refined test methods to measure condensable PM, with the goal of achieving a more reliable standard in time for the initial MACT compliance date; however, the commenter believes that given the benefits of reducing condensable PM, the EPA should not let testing uncertainty prevent the implementation of the total PM standard. Commenter 17402 refers to the EPRI CEMS Users Group in Chicago, IL on June 8, 2011 and a presentation given by Clean Air Engineering ("CAE") entitled "Description of a Potential Pseudo CPM Formation Mechanism in New EPA Method 202" for a CFB boiler equipped with an SNCR. The paper concluded that due to its high affinity for water, free NH_3 in the gas stream will be absorbed in the aqueous layer of the Method 202 impingers and will react with SO_2 to form either ammonium sulfate or bisulfate. According to commenter 17402, CAE recommended that ammonium sulfate or bisulfate formed in the Method 202 dry impingers should be considered an artifact and the commenter quoted CAE's suggestion that "the EPA should acknowledge that significant positive biases related to the interaction of SO_2-NH_3-H_2O can occur in the new M202, and should also allow for quantification and correction" of this artifact using procedures prescribed by CAE or the EPA should modify Method 202 to reduce or eliminate the bias. Commenter 17402 states that subtracting the inorganic condensable PM from Method 202 and adding the inorganic condensable PM from CTM-013 (controlled condensation) was one of the steps included in the proposed procedure.

Comment 18: Commenters 17725 and 18498 state that using only filterable particulate (in conjunction with SO_2 or HCl for selenium) as a surrogate for non-Hg metals from coal combustion would avoid various problems associated with including condensable particulate as part of the standard. According to the commenters one of the fundamental problems with using Method 202 for condensable PM measurements is that the results are overwhelmingly driven by sulfate and nitrate compounds, which have nothing to do with metal HAP emissions. According to the commenters, Method 202 is also problematic because of its high bias tendencies; the method is intended to provide a measure of condensable "primary particulate," which is not PM at stack conditions but which condenses upon cooling and dilution in the ambient air to form PM, as opposed to "secondary particulate," which forms later as different compounds react and combine in the atmosphere over time. The commenters acknowledge that one might argue over the merits of requiring sources to include condensable PM as part of a measure to control ambient particulate/haze but assert that Method 202 is prone to biases due to SO_2 artifact formation (again, something that has nothing to do with metal HAP) that make the results especially unreliable in conjunction with the long run times proposed under this rule. According to the commenters, while Method 202 was revised to include a nitrogen purge and an initial dry impinger (which is quickly wetted with condensation from the flue gas) to reduce these artifacts, the remaining SO_2 related artifacts can be significant at low levels. Also, according to the commenters, because of the bias, extending the run time does not necessarily improve the accuracy or detection limit since it simply provides more time for the artifacts to form and, thus, tends to defeat the purpose of adding the purge/dry impinger. The commenters state that recent studies have shown the SO_2-related artifact formation to be particularly acute if there is any NH_3 in the flue gas (e.g., slip from an SCR for NO_X control), which again is not related to primary particulate and certainly not related to metal HAP in any way and cite Bionda, J. and Evans, S., Description of a Potential Pseudo CPM Formation Mechanism in New EPA Method 202, 2011 EPRI CEM Users Group Conference, Chicago, Illinois (June 8-10, 2011).

Comment 19: Commenter 17821 states that although the revisions of Method 202 finalized in 2010 have been demonstrated in the laboratory to reduce sulfate and other artifact formation, the EPA's data show that it does not completely eliminate the high bias associated with the test method: "EPA reported experimental results that showed the dry impinger modification to Method 202 reduced sulfur dioxide artifact formation by more than 90%." See Method 202 Assessment and Evaluation for Bias and Other Uses Evaluation of Stakeholder Recommendations August 4, 2006 through April 17, 2007.

Comment 20: Commenters 18935 and 18034 note that the new version of Method 202 published in December 2010 is substantially different from Method OTM 28, which was used to generate ICR data. The commenters express concern that the proposed rules have been developed from a dataset derived from slightly different methodology than that which will be used to demonstrate compliance with the proposed rules. Given the different train configurations and operating temperatures, the commenters suspect that OTM 28 data are not directly comparable to Method 202 and therefore sources may have difficulty planning or demonstrating compliance without substantial comparative testing.

Comment 21: Commenter 17820 states that Method 202, recently finalized by the EPA to measure condensables, is still prone to biases due to SO_2 artifact formation that has nothing to do with metal HAP and makes resulting PM measurements questionable.

Response to Comments 16 - 21: The final rule does not require the measurement of condensable PM as a part of an alternate equivalent standard for non-Hg metals, so we need not address these comments.

6. Comments related to frequency of stack testing.

Comment 22: Commenter 17775 states that the EPA must clarify the Hg testing requirements. The commenter states that in the preamble, the EPA states that additional performance tests for Hg are conducted "at least annually." (Proposal Preamble, 76 FR 25,029/3). The commenter agrees that Hg testing should not be required any more frequently than annually. However, according to the commenter, there is no reference to this annual testing in the proposed rule. Instead, according to the commenter, the rule requires testing either monthly, or every other month, for "individual or total HAP metals" and cites Proposal section 63.0006(f) and (g). The commenter states that the agency should revise its proposal to reduce all stack testing to no more frequently than annual. According to the commenter, there is no reason to require Hg testing in addition to "individual or total HAP metals" testing.

Response to Comment 22: In the final rule, annual Hg testing is required as part of demonstrating the continued applicability of the LEE provisions for a unit that qualifies as an LEE for Hg. For units with Hg CEMS or sorbent trap monitoring systems, Hg performance tests are not required on an annual basis, although the monitoring systems will be subject to ongoing QA, including RATA tests.

Comment 23: Several commenters (17730, 17775, 17808) express concerns about the number of stack tests required under the proposal's stack testing compliance options. Commenter 17808 expresses concerns about the monthly or bi-monthly stack testing requirements in the proposed rule for units not measuring emissions continuously. For example, the commenter notes, liquid oil-fired EGUs would be required to test for all HAP metals on a monthly basis if they do not have a PM control device installed, or once every two months if they do have a PM control device. Additionally, the commenter notes, they would need to test for HCl and HF on a monthly basis because there are no controls currently installed for addressing these pollutants at oil-fired EGUs. According to the commenter, coal-fired EGUs would face similar obligations. Commenter 17808 believes that the proposed frequency of testing will place a significant cost burden on plant operators. According to the commenter, stack testing can also be unsafe for testing personnel during harsh weather conditions, particularly the cold winter months. Finally, according to the commenter, inflexible testing schedules may induce units to run solely for testing purposes, leading to increased emissions. In addition to company costs and staff time, the commenter notes that state-level environmental regulators may need to be on site to witness the tests and expresses concerns that the large number of units affected by the rule and the proposed testing frequency could make staff availability a significant issue. The commenter is also concerned that this could result in delayed compliance testing or not being able to dispatch a unit (that has not been able to schedule required compliance tests). In an effort to balance these concerns with the need for reliable compliance demonstrations, the commenter recommends that all stack testing requirements be no more frequent than quarterly under standard operation (i.e., unless boiler operations or characteristics are substantially altered, in which case initial testing should be repeated). The commenter believes that quarterly stack testing in combination with parameter monitoring should be enough to ensure that a unit is operating within the required limits because quarterly testing would capture seasonal variations in operation while not unnecessarily repeating tests at the same conditions. Commenter 17730 characterizes the proposed monitoring option for sources not using CEMS as excessive and overly burdensome because the commenter believes the requirement to conduct stack testing either monthly or bi-monthly is a very expensive and time consuming operation, especially when testing at the very low levels necessary to comply with the proposed MACT standards. The commenter states that the sampling times that will be necessary to collect enough sample volume to record values over the method detection limits will require extended hours of testing operations, and the extended hours of testing further increase compliance costs. Commenter 17730 believes that compliance with monthly stack testing requirements will put sources in a nearly continuous mode of stack testing. The commenter recommends that the agency consider requiring stack testing on an annual basis combined with an appropriate level of parametric monitoring and defined operating limits because such requirements are adequate to ensure compliance and to protect public health and the environment. Commenter 17775 also expresses concerns with the proposal's stack testing options for HAP metals with respect to the frequency of repeated stack tests and states that the EPA has provided no rationale or data for the proposed frequency of stack testing or accounted for the cost of such frequent testing in its proposed ICR. The commenter references the EPA's supporting statement for the February 2011 proposed ICR describing the existing source requirement as testing with Method 29 initially and every 2 years thereafter. [EPA-HQ-OAR-2009-0234-3031 at Tables 1a, 1b, 1c.] However, the commenter interprets the statement as assuming that no source will perform anything other than initial testing. The commenter states that the proposed frequency of testing is by definition arbitrary and capricious and contends that EGUs demonstrating initial compliance through stack testing and confirming compliance by monitoring and responding to appropriate operating parameters should not need to conduct additional stack tests more frequently than annually, unless the EGU's fuel type or controls change. The commenter contends that such frequent testing adds nothing but cost and states that the agency points to no other variables to justify such frequent testing. The commenter acknowledges that the proposal allows some provisions for reduced testing, but counters that the 50 percent criteria for qualify for these provisions makes them too restrictive to be useful.

Comment 24: Comment 18498 states that the frequency of the additional performance testing requirements is not consistent with the expected variability in stack emissions. Units without add-on control systems are required to complete stack tests less frequently than units with add-on control systems. According to the commenter, for units without add-on control systems, the emissions of HCl, HF, and non-Hg metals are most closely tied to fuel characteristics. In lieu of requiring more frequent performance tests if a source chooses to use the alternate standards for certain subcategories, the commenter recommends periodic fuel analysis to determine if a significant change has occurred since the previous performance test. According to the commenter, if there is a significant change of fuel HAP concentrations then additional emissions testing might be warranted but the source's expected removal efficiency should also be taken into consideration to minimize unnecessary testing. The commenter believes that annual performance testing is sufficient to demonstrate proper operation of control devices and has historically been sufficient.

Comment 25: Commenter 18498 states that because many liquid oil-fired sources operate infrequently and only during peak demand periods for liquid oil-fired sources, the proposed testing magnifies the burden of frequent testing. The commenter notes in the preamble the EPA found that for liquid oil-fired units, no correlation was found between non-Hg metallic HAP emissions and PM emissions or the operation of PM control devices. As such, according to the commenter, the emissions of HCl, HF, and non-Hg metals are most closely tied to fuel characteristics and thus it would be more meaningful to assess fuel characteristics and use that information to determine whether additional emission testing is needed.

Comment 26: Commenter 18025 states that they support the proposal to allow existing sources the option to comply with input- or output-based standards, and recommend that the EPA maintain this flexibility in the final rule. However, the commenter believes that the proposed compliance demonstrations are unnecessarily frequent, and recommend quarterly testing for all HAP. According to the commenter, quarterly testing provides the necessary performance guarantee, while balancing the substantial costs of stack testing.

Response to Comments 23 - 26: In response to comments, the final rule has been amended to include quarterly periodic testing and retains the option to comply with input-or output based standards for existing units. For liquid oil-fired units that use the quarterly performance test option, the source will also need to develop a site-specific monitoring plan to ensure that operations between tests remain consistent with the operations during the performance test. Please see the final preamble for further discussion.

Comment 27: Commenter 17880 supports the requiring of coal-fired, IGCC and solid oil-derived fuel-fired units to conduct HAP metals and PM testing at least every 5 years, using the current process outlined by EPA Methods 29, 5, and 202. Additionally, the commenter states, units that have elected to comply with the HAP metals emission limits instead of total PM emissions limits would be required to conduct total or individual HAP emissions testing every 2 months to demonstrate continuous compliance.

Comment 28: Commenter 17191 states that for IGCC units, the proposed rule requires either use of PM CEMS or Method 29 stack testing and that Method 29 is required every 2 months if PM controls are installed or every month if no PM controls are installed. The commenter requests that this requirement be clarified to indicate that the "PM controls" can be pre-combustion controls such as the gasification process for IGCC units because traditional post-combustion PM controls are not used in IGCC systems. Commenter 17191 states that PM is captured "upstream" of the combustion turbine in the gasification phase and that such a design configuration should not be used to require monthly stack testing under the Method 29 compliance option.

Response to Comments 27 - 28: In the final rule, if a PM CPMS is used, the source must reestablish the operating limit by conducting a test every year, not on a 5-year basis. This approach recognizes that the operating limit associated with the PM CPMS is a surrogate operational requirement that does not provide the same degree of assurance as a direct measurement of the emissions limit, and needs to be re-established over time. With respect to the frequency of tests where continuous monitoring is not used to demonstrate compliance, the final rule does not distinguish between units with or without controls, so the concerns on how to classify IGCC combustion controls are inapplicable.

7. Comments related to derating units.

a. Compliance Plans to temporarily derate units while air pollution control upgrades are completed.

Comment 29: Commenter 17402 states that the EPA should clarify that stack testing may be performed at loads where facilities can meet all emissions and operating parameters because some upgrades required to meet certain MACT standards may not be fully operational as of the compliance deadline, and the commenter believes that compliance prior to completion of air pollution control upgrade projects can only be achieved by operating such units at reduced load. Commenter 17402 requests that the EPA clarify that "maximum normal operating load" under the proposed performance test guidelines can include short-term, full-load operating restrictions if such generating load restrictions are necessary to ensure compliance in advance of completion of air pollution control upgrades. Commenter 17402 notes that in proposed section 63.10007(c), the EPA specifically allows for the conducting of tests at "differing operating limits," implying that the EPA expects the operating load to be somewhat flexible, and the commenter states that the EPA should not require operations during a performance test which the operator knows will cause a violation. Instead, the commenter requests that the final rule allow operators to choose an interim compliance operating level for up to 3 years so that the operating limits set based on the most recent performance test well temporarily limit maximum capacity to 110% of the operating load achieved during the most recent performance test.

Commenter 17402 additionally requests provisions in the final rule that would allow facilities that choose to restrict load (while air pollution control upgrades are installed) to resume operations at the pre-MACT, full-load capacity upon demonstrating compliance at the true maximum capacity during a periodic performance test. The commenter notes that the EPA has supported interim control strategies previously, including voluntary capacity reductions.

Response to Comment 29: The EPA believes the proposed and final rules already provide for this type of flexibility. If a source adopts a derate restriction as a condition of its federally enforceable operating permit for a source, then testing at full load for that source would be conducted in accordance with the terms of the permit as to what full load means. As part of modifying the permit to lift the restriction, the EPA would anticipate that testing to demonstrate compliance with this rule would be part of the action that a source would need to take in order to demonstrate compliance.

b. NSR implications of interim MACT compliance strategies involving derates.

Comment 30: Commenter 17402 requests, regarding temporary measures to administratively derate a unit to a generating capacity that can comply with MACT standards while air pollution control upgrades are installed, that the EPA provide clarification on the implications of such a compliance strategy under the NSR program. The commenter believes that once the emissions controls are installed and fully operational and the facility ends the voluntary capacity reduction, prevention of significant deterioration (PSD) or NSR should not be triggered provided that there is no significant increase in emissions from 2 consecutive calendar years of operations prior to the interim control strategy's implementation. According to the commenter, since "baseline actual emissions" are defined as any consecutive 24-month period from the 5 years prior to the start of construction, an operator could reasonably choose 24 months from the period preceding the interim control strategy's voluntary capacity reduction, provided that construction started within 3 years of the interim control strategy implementation. The commenter states that "increase" is defined as the difference between baseline and potential annual emissions, where potential is the maximum projected emissions in any of the next 5 years. As a result, according to the commenter, with a properly designed control upgrade, a facility's operating capacity before and after the interim control period would be identical, and the emissions in question would decrease. Given the clear emissions reductions, and conformity with existing regulations, the commenter requests that the final rule confirm that the use of an interim control strategy of voluntary capacity reductions will not result in triggering NSR or PSD requirements.

Response to Comment 30: PSD permit implications of the derate strategy mentioned by the commenter would be addressed in accordance with the implementing regulations and accompanying guidance for the NSR program as in effect at the time of such compliance approach taken by the source. Those implications are not part of this rulemaking, and the EPA will respond to specific questions and requests for guidance on a case-specific basis under the normal procedures established for issuing guidance and policy interpretations under the NSR program.

8. Comment related to bypass requirements – CEMS.

Comment 31: Commenter 17675 states that the requirement in section 63.10010(a)(4) for installing, operating, and maintaining a complete CEMS system on a bypass stack is not appropriate for EGUs that only use the bypass stack for a short time during startups and shutdowns because such a requirement is excessive, unnecessary, and difficult to maintain in a state of readiness for a few hours of usage on an occasional basis. The commenter believes that alternative monitoring methods such as data substitution techniques similar to those used in 40 CFR part 75 or fuel sampling for Hg during startups and shutdowns must be allowed rather than requiring installation of a duplicate and seldom utilized CEMS system for a startup bypass stack.

Response to Comment 31: The EPA has modified the bypass stack monitoring requirements. Under 40 CFR Part 75, the EPA allows the use of a maximum potential concentration value on a bypass stack. That approach works within the broad context of an emissions trading program but does not work when evaluating compliance with a specific emission limit over a shorter period. Thus, the final rule provides two other options for a source. One is to monitor the bypass stack consistent with the proposed rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime. In general, this is consistent with the EPA's approach to startup and shutdown periods, in that we treat those periods as subject to a work practice standard. That generally obviates the need to monitor the bypass stack as the emission limit does not apply during the periods when the source is most likely to operate a bypass stack. Use of a bypass stack at times when the source is operating and the emission limit applies (i.e., other than startup or shutdown periods), will mean a failure to monitor emissions at all times in accordance with the rule.

9. Comments related to duplicative testing.

Comment 32: Several commenters (17820, 17868, 18014) state that the EPA is requiring stack tests for both the pollutant and surrogate and that this requirement is superfluous. The commenters state that the EPA has established alternative limits for compliance for various HAP groups. For example, state the commenters, coal-fired units may choose to meet either the PM limit, the limits for individual metals, or a total non-Hg metals limit to establish compliance for metal HAP and may monitor SO_2 or HCl for acid gas HAP, and these options provide the sources with a measure of flexibility. According to one commenter, since limits for each pollutant (or surrogate) have been independently established to assure effective reductions in accordance with section 112 of the CAA, there is no need to test for both the pollutant and surrogate. The commenters indicate that a performance test should only be required for the pollutants and surrogates with which the source is choosing to show compliance.

Comment 33: Commenter 17775 believes that the EPA's proposed compliance demonstration, recordkeeping, and reporting requirements are flawed because the applicability of many provisions is unclear and the EPA fails to provide any rationale by which the provisions' basis and purpose might be discovered. The commenter states that for the first time in any MACT, and without explanation, the EPA proposes to require that EGUs exercising the option to comply with a surrogate emission limit also stack test for the corresponding HAP, and conversely, that EGUs opting to comply with a HAP limit stack test for the corresponding surrogate. According to the commenter, these duplicative testing requirements are inconsistent with the agency's legal and policy justifications for the use of surrogates and are otherwise unsupportable. The commenter states that for EGUs that opt to comply with a chosen emission limit using stack testing, the EPA (again without explanation) requires stack testing no less frequently than every other month, requires compliance with established "operating limits" on control devices, and requires compliance with fuel input limits. According to the commenter, the agency provides no rationale for the selected frequency of stack testing and fails to include the associated cost in its proposed ICR. According to the commenter, the requirements are unnecessary and inconsistent with the EPA's prior position on use of surrogates, numerous preamble statements claiming cost savings by use of surrogates, and the proposal to allow EGUs to choose whether to comply with a HAP limit or, where surrogates are proposed, the surrogate limit. The commenter states that where the EPA has demonstrated the appropriateness of use of a surrogate and selected an emission limit for that surrogate that is consistent with what the best sources achieve, there is no basis for also requiring the source to test for the applicable HAP. According to the commenter, the EPA says as much in the preamble, and the commenter cites portions of the preamble (including the following portions and language: the agency summarizes the D.C. Circuit decision in *National Lime Ass'n*, 233 F.3d 625: If these criteria are satisfied and the PM emission standards reflect what the best sources achieve -- complying with CAA section 7412(d)(3) --" EPA is under no obligation to achieve a particular numerical reduction in HAP metal emissions.'' We have considered this case in evaluating whether the surrogate standards we propose to establish in this proposed rule are reasonable. 76 FR 25,021/3. The EPA has satisfied the criteria for use of PM, HCl, and SO_2 as surrogates. See 76 FR 25,039/3, 25,040/1, 25,041/1.). According to the commenter, the same is true with respect to testing for surrogates. The commenter states that where the EPA has established an emission limit for a HAP that is consistent with what the best sources achieve, there is no basis for also requiring testing of a surrogate. Commenter further notes that in *National Lime Ass'n*, the EPA's position with respect to use of PM as a surrogate was that it "'achieves exactly the same level of HAP metal emissions limitations' as would be reached were the metals to be regulated directly," and that the "use of a surrogate 'eliminates the cost of performance testing to comply with numerous standards for individual metals" (citing F.3d at 637 (quoting 64 FR 31,916/3)). According to the commenter, the Court found the EPA's use of the surrogate reasonable (citing id. at 639). If the HAP limit and the surrogate limit provide equivalent control, the commenter asserts, there is no reason to test for both, at any frequency, and the EPA has not suggested any purpose. The EPA also has not required such duplicative testing in any other rule that relies on surrogates.

Commenter 1775 also asserts that requiring testing for both the HAP and surrogate is inconsistent with Tables 1 and 2, which, according to the commenter, establish surrogate emission limits as "alternatives" to HAP emission limits and vice versa. According to the commenter, requiring EGUs to test for HAP, when they have opted not to meet the HAP limit, or requiring EGUs to test for a surrogate, when they have not opted to meet a surrogate limit is completely unreasonable. The commenter states that the tests have no regulatory purpose under the proposed rule and the EPA's preamble summary identifies none. The commenter states that the EPA discussed the cost savings associated with using surrogates and refers to 76 FR 25,038; at 25,039; at 25,059.

Commenter 17758 also disagrees with the proposal's requirement to test for surrogates at units using the stack testing compliance option for non-Hg HAP metals and HCl, because according to the commenter, if a utility has chosen to demonstrate ongoing compliance by directly measuring the regulated HAP, it is superfluous to require any further testing of surrogates, and under the stack testing compliance option the agency should specify that performance tests only for methods necessary to measure the regulated HAP are required.

Comment 34: Commenters 17881 and 18428 state that where a surrogate is used the requirement to test for the applicable HAP is duplicative and should be removed. For example, according to the commenters, sources using PM as a surrogate for non-Hg HAP metals must perform metals testing in addition to stack testing for total PM and establishing a filterable PM limit and demonstrating compliance with PM CEMS, and similarly, sources using SO_2 as a surrogate for HCl must test for HCl in addition to the SO_2 CEMS performance test. Commenter 18428 notes that for EGUs that do not choose to use a surrogate, the EPA proposes to require testing for surrogates anyway. For example, notes the commenter, proposed section 63.10006(d) requires EGUs without PM CEMS, but with a PM control device, to perform annual tests for both PM and non-Hg HAP metals. Similarly, proposed section 63.10006(h) requires EGUs without SO_2 CEMS to conduct "all applicable performance tests" for SO_2 and HCl annually and, for units with SO_2 controls, to conduct SO_2 emissions testing "at least every other month." See also preamble, 76 FR 25,051. According to the commenter, where the EPA has demonstrated the appropriateness of use of a surrogate and selected an emission limit for that surrogate that is consistent with what the best sources achieve, there is no basis for also requiring the source to test for the applicable HAP. The commenter asserts that where a source chooses to comply with the HAP limit, testing for surrogates is unnecessary and unreasonable. The commenter also views both requirements as inconsistent with Tables 1 and 2, which, according to the commenter, establish surrogate emission limits as "alternatives" to HAP emission limits and vice versa. The commenter states that although the EPA describes these duplicative testing requirements in the preamble, the EPA provides no rationale to support them.

Comment 35: Commenter 18015 states that section 63.10000(c)(1) of the proposed rule provides that for all coal-fired and solid oil-derived fuel-fired units the initial performance testing is required for all pollutants. According to the commenter, this implies that for HCl, owners and operators would be required to conduct performance tests for both HCl and $SO_{2,}$ and for HAP metals, owners and operators would be required to conduct performance tests for both PM and all individual HAP metals. According to the commenter, this is inconsistent with the intent established in the preamble that facilities must conduct performance tests to demonstrate compliance with all applicable emission limits. According to the commenter, if a facility chooses to use PM as a surrogate pollutant and meet the PM limit set forth in Table 1 or 2, then that becomes the applicable emission limit, and the HAP metals emission limits are no longer applicable. The commenter asserts that this is supported by the fact that continuous compliance is based on PM CEMS or other PM-related compliance mechanisms. Conducting the additional emission tests for individual HAP increases the cost and labor time for no added benefit, according to the commenter, because the facility will be complying with the PM emission limit, not the individual HAP metals emission limits. Thus, states the commenter, initial compliance should only apply to the applicable emission limit and result in testing of only the surrogate pollutant, PM, not HAP metals.

Comment 36: Commenter 18034 states that proposed section 63.10006 requires coal-fired and solid-oil derived fuel-fired EGUs to perform testing for non-Hg metal HAP even if the source elects to use total PM as a surrogate for the non-Hg metal HAP limits. The commenter states that similarly, the same source categories are required to perform HCl testing even if the source elects to use SO_2 as a surrogate for HCl. Furthermore, the commenter states, on-going compliance for units that are not equipped with CEMS is through monthly or bi-monthly stack testing for pollutants that are the primary HAP when the source is using a surrogate limit for the HAP. According to the commenter, the preamble (76 FR 25029) states that the purpose of the stack testing is demonstrate compliance with all applicable emission limits; however, if a coal-fired EGU is using the PM surrogate option, the unit is not subject to the non-Hg metal HAP limits and a demonstration of compliance is not necessary. The same issue applies to an EGU using SO_2 as a surrogate for HCl, the commenter states. According to the commenter, the EPA provides no explanation for why the proposed rule requires sources to test for pollutants for which there are no applicable emissions limits. The commenter also asserts that section 63.10006 is inconsistent with the EPA statements in the preamble that use of the PM surrogate would eliminate costs associated with conducting performance testing for non-Hg metals (76 FR 25039). According to the commenter, these additional testing requirements provide no added compliance assurance for the rule and unnecessarily impose extensive burden on regulated sources as well as state agencies that are delegated enforcement authority for the NESHAP and responsible for overseeing required stack testing. The commenter asserts that if these overlapping testing provisions are inadvertent, then the EPA must revise the rule to clearly indicate that sources are not required to test or monitor for HAP when a surrogate limit for those HAP has been selected. However, states the commenter, if the EPA is intentionally requiring sources to test for HCl and non-Hg metal HAP even if the sources are using a surrogate limit and do not have to demonstrate compliance with the specific HAP, then the EPA must provide a reasoned justification for the additional testing and explain the intended purpose of the test results.

Comment 37: Commenter 17868 states that the EPA must remove the requirement for SO_2 performance testing. According to the commenter, proposed section 63.10006(h) and (i) include testing provisions for SO_2 for units without SO_2 CEMS. According to the commenter, the EPA must make clear that these provisions do not apply to EGUs complying through HCl stack performance testing. The commenter states that there is no basis for testing of the surrogate SO_2 at a unit that is complying with the HCl standard. In addition, according to the commenter, the proposed rule does not provide any procedure for SO_2 performance testing or an SO_2 emissions standard other than those applicable to units with SO_2 CEMS. The commenter states the EPA has no basis to require EGUs that choose to comply through stack testing to also install an SO_2 CEMS.

Response to Comments 32 - 37: In response to comments, the final rule has removed all requirements for testing of both the individual HAP and the surrogate. Facilities complying with a surrogate limit do not have to perform periodic testing for the corresponding HAP.

10. Comments related to non-Hg metal standards.

Comment 38: Commenter 17775 supports the proposed inclusion of an option for non-Hg HAP metals stack testing (i.e., Method 29) but contends that the proposed rule contains duplicative testing requirements under the non-Hg HAP metals stack testing option. The commenter believes that to make it a reasonable option, the final rule must reflect several adjustments:

1. First, the commenter believes the final rule must remove the requirement for annual PM testing under section 63.10006(d) because no justification is provided for this requirement. Furthermore, notes the commenter, proposed Tables 1 and 2 clearly provide sources the option of meeting either a PM or non-Hg metals limit. Testing for PM when that option has not been selected and no limit applies is nonsensical. The commenter concludes that requiring testing for a surrogate in addition to the regulated HAP is beyond the agency's authority.
2. The commenter believes that the EPA should re-evaluate the proposed operating parameter requirements because the operating parameters specified for non-Hg metal controls are not sufficiently connected to metals removal or sufficiently flexible to be used as enforceable limits. The commenter contends that secondary power is not directly related to PM removal and that pressure drop and liquid flow will vary with load. Moreover, according to the commenter, at the level of the proposed standard, metals control may not be very sensitive to liquid flow. The commenter states that the final rule must allow for adjustment of load-dependent operating parameters to account for load changes, and the final rule should use the operating parameters as indicators, not enforceable limits.
3. The commenter states that the final rule should make clear that EGUs combusting a single fuel type are not required to make any determination regarding that fuel under section 63.10011(b)(3)(i) (requiring determination that the fuel type or mixture has the highest content of non-Hg HAP metals)

and that EGUs using supplemental fuels qualify as single fuel EGUs. The commenter notes that although the proposal attempts to address that issue for liquid oil-fired EGUs in section 63.10005(c)(4) and section 63.10011(c)(1), those provisions apply only to liquid oil-fired EGUs complying through fuel analysis.

4. Commenters 17775 and 17868 state that the final rule should specify minimum detection limits for laboratory analyses and provide procedures for calculating combined concentrations of single metals and total non-Hg metals. According to Commenter 17775 the data collected in the 2010 ICR indicated the reported detection limits for laboratory analyses were highly variable even for data for the same metal and from the same laboratory. To determine compliance on a consistent basis, the final rule must specify minimum detection limits and a procedure for combining front and back half fractions to report total concentrations.

Response to Comment 38: We agree that maintaining low method detection levels is critical in demonstrating compliance with the applicable emissions limits for this MACT rule. We disagree that we can provide default values for method detection levels to use in determining compliance since there are many site-specific factors that can affect method detection levels for any one set of data. In achieving the most effective testing including method detection levels commensurate with compliance determinations, the tester must consider multiple technical and procedural choices and analytical laboratories used in any test program. There are some testing factors that we believe are appropriate for the rule to address including minimum sample volume and some specific analytical finishes; however, those required elements do not lead directly to maximum method detection levels. The EPA agrees about the need for a procedure to combine the front and back half fraction and has revised the final rule to address this concern. It is difficult to define maximum acceptable method detection levels that would adequately account for the myriad of test matrices, interference, various types of analytical finishes, and final analytical volumes that could very well be effective for all situations. Instead, the rule includes a requirement that specifies how to use method detection level information in calculating compliance with the emissions limits. The language in the final rule is similar to that found in the Mercury cell Chlor-alkali plant regulations (see § 63.8232(c)(1)). The source must use the test specific method detection level in calculating compliance with an emissions limit for any value measured and reported as below detection level.

On the other issue of method detection capabilities for fuel sampling and analyses, the removal of the proposed fuel input operating requirements in the final rule renders the concerns about identifying highest fuel mixture and supplemental fuels no longer relevant.

11. Comments related to HCl standard testing.

Comment 39: Commenter 17775 expresses the following concerns with the HCl stack testing option:

1. The commenter supports the proposed inclusion of an option for HCl stack testing. However, the commenter contends that to make it a reasonable option, the final rule must include several adjustments. First, the commenter states, the EPA must remove the entire requirement for SO_2 performance testing under this option because there is no basis for testing of the surrogate SO_2 at a unit that is complying with the HCl standard. In addition, the commenter states, the proposed rule does not provide any procedure for SO_2 performance testing, or an SO_2 emissions standard other than those applicable to units with SO_2 CEMS. The commenter states that the EPA has no basis to require EGUs that choose to comply through stack testing to also install an SO_2 CEMS.
2. Second, according to the commenter, the EPA should re-evaluate the proposed operating parameter requirements because the operating parameters specified for HCl are not sufficiently connected to

HCl removal or sufficiently flexible for use as enforceable limits. The commenter states that the EPA also must allow for adjustment of load-dependent operating parameters to account for load changes and should use the operating parameters as indicators not enforceable limits.

3. Third, according to the commenter, the EPA should make clear that EGUs combusting a single fuel type are not required to make any determination regarding that fuel under section 63.10011(b)(1)(i) (requiring determination that the fuel type or mixture has the highest chlorine content) and that EGUs using supplemental fuels qualify as a single fuel EGUs. The commenter states that although the agency has attempted to address that issue for liquid oil-fired EGUs in section 63.10005(c)(4) and section 63.10011(c)(1), those provisions apply only to liquid oil-fired EGUs complying through fuel analysis.
4. Fourth, the commenter re-iterates previously stated concerns about the frequency of stack testing required under the stack testing compliance option but relates the concerns to the HCl standard rather than HAP metals standard.

Response to Comment 39: The final rule has been amended to remove the requirement for testing of both SO_2 and HCl. Operational parameter requirements specified for HCl have been removed. The frequency of periodic testing has been reduced to quarterly testing. With the removal of the proposed fuel input operating requirements in the final rule, the concerns about identifying highest fuel mixture and supplemental fuels are no longer applicable.

Comment 40: Commenter 17807 states that preliminary HCI testing using Method 320 (FTIR) and Method 26 generally show a considerable disparity in the reported concentration of HCl. According to the commenter, Method 26A is reported to be approximately 5 to 10 times higher than Method 320. The discrepancy is considered significant despite sampling on different dates and taking into account variances in chemical composition of coal. According to the commenter, this data supports the high biases of chlorides from FGD systems running with high equilibrium chloride concentrations. Furthermore, asserts the commenter, the test results imply Method 26A may not be an appropriate test method for testing HCI emissions in wet stacks. The commenter suggests the EPA evaluate these discrepancies in wet stacks using Method 320. (See 17807-A1_Table_2_&_3.doc.)

Response to Comment 40: The EPA has amended the final rule to include the option for periodic HCl testing by Method 320.

Comment 41: Commenter 17696 states that coal-fired EGUs without an HCI CEMS should be allowed to reduce the frequency of HCI stack testing or fuel analysis if the EGU's initial performance test is less than 50% of the standard. According to the commenter, for coal-fired EGUs that do not install an HCl CEMS, proposed section 63.10006(k) and (l) require performance testing either monthly (for EGUs without an FGD) or every other month (for EGUs with an FGD). Commenter 17696 contends that for EGUs whose initial emissions stack test is less than 50% of the applicable HCl emission limit, monthly or bi-monthly performance testing for HCl is excessive, unnecessary and unduly burdensome. According to the commenter, EGUs that emit at such low HCl emission levels are able to do so as a result of the chlorine content inherent in their fuel. As long as there is no change in fuel, the commenter asserts, there is no expected change in the level of HCl emissions. The commenter suggests that an alternative approach for sources testing at less than 50% of the standard is to require subsequent performance tests less frequently, such as semiannually. Commenter 17696 also states that a 50% threshold would be consistent with the threshold for reduced frequency of monitoring in proposed section 63.10006(o) and states that operating parameters and fuel analysis demonstrating no material changes in the fuel supply are sufficient to assure compliance with the applicable HCl emission limit between semi-annual performance tests.

Response to Comment 41: The final rule has been amended to require quarterly HCl testing for sources not using an HCl/HF or SO_2 CEMS option. The EPA disagrees that one performance test at 50% of the emission standard would be adequate to ensure compliance. However, the final rule adopts a LEE provision for pollutants other than Hg that enables a source to move to annual testing if all tests for the applicable pollutant over a 3-year period are less than 50% of the emission limit.

Comment 42: Commenter 17754 requests that the EPA revise the compliance demonstration requirements applicable to EGUs achieving LEE status for Hg, and the commenter contends that the final rule should provide an additional compliance option for LEEs with Hg emissions below 50% of the applicable LEE threshold; according to the commenter, such very low emitting EGUs should be allowed to demonstrate continuous compliance through annual stack testing and should not be required to conduct monthly fuel analyses.

Response to Comment 42: The LEE threshold for Hg remains at the 10% threshold that the EPA proposed (or the total mass limit of <29 pounds per year, as requested by another commenter for consistency with existing state rules). However, there is no monthly fuel analysis requirement for units that qualify, but rather an annual test, consistent with the commenter's recommendation.

12. Comments about concerns with combined stack.

Comment 43: Commenter 18932 states that the use of combined stacks will undermine monitoring and enforceability because the stringency and practicable enforceability of an emission standard depends largely on the precision of its associated monitoring regimen. The commenter asserts that monitoring requirements that do not reflect appropriate averaging times based on applicable emissions or air quality standards do not assure continuous compliance with those standards. Similarly, the commenter states, to assure that each EGU meets all applicable MACT emission standards, the Utility Air Toxics Rule must specify monitoring requirements that will accurately measure and record the HAP emissions from each individual source. The commenter does not believe that the proposed rule will accurately measure and record emissions from individual sources and believes that the agency must clarify monitoring requirements in cases where multiple individual units co-located at a single facility exhaust through a combined stack. According to the commenter, this problem arises in two ways: (1) when multiple emission sources vent gases through separate flues that are physically located within the same stack; and (2) when multiple emission sources vent commingled exhaust gases through a common stack.

The commenter asserts that, first, there are many cases where multiple individual units exhaust through individual flues that are co-located within a combined stack. According to the commenter, the rule should make it clear that, in such cases, individual flues should be monitored separately, since there is no impediment to doing so. According to the commenter, the combined stack, in these instances, is simply the structural unit that encloses the flues, which are the separate, functional, exhaust gas emission points.

The commenter also asserts that there are many other instances where the exhaust gases generated by individual EGUs enter, commingle, and exhaust through a common stack. According to the commenter, to assure that each EGU that vents through a combined stack complies with applicable MACT standards, the EPA should require separate monitoring and reporting of each unit's HAP and surrogate emissions prior to the exhaust gases commingling in the stack, such as prior to the stack breeching. According to the commenter, a monitoring regime that does not require each source to separately monitor and report its HAP emissions will not assure that each covered EGU complies with all applicable MACT requirements. The commenter provides an example of monitoring emissions at both types of combined stacks.

Response to Comment 43: A common stack with individual flues (and no commingling of emissions from the individual units) will require monitoring and testing on each separate gas stream. Each flue would be the monitored or tested location at any unit that operates in such a manner. For the more typical common stack situation in which emissions from multiple units may be released through a single combined stack, the rule allows for either separate monitoring at the unit level or monitoring of the combined emissions. In the latter case, any failure to meet the standard at the combined location would be deemed a separate compliance issue for each individual unit to which the standard applies.

13. Comments about using total PM.

Comment 44: Commenter 17621 states that the use of total PM as a surrogate parameter for HAP metals is problematic due to shortcomings in the test methods for the two components of PM (filterable and condensable PM). According to the commenter, particulate monitors measure only the filterable portion of total PM, and the manual stack test methods for both filterable and condensable PM are of uncertain accuracy.

Commenter 17621 also states that the EPA's rationale for including condensable PM in the MACT limit to represent selenium is not supported.

Comment 45: Commenter 17877 states that the proposed total PM MACT is unworkable for several reasons. According to the commenter, while Method 5 is more accurate in the short run, it does not (and cannot) account for variations in filterable PM actual levels over a range of unit operating levels as would a less accurate PM CEMS. Optical, light scatter, and light extinction PM CEMS are not accurate enough to acquire meaningful values for developing a PM limit, but they could be used to determine variability. According to the commenter, Laser Beta Gauge or Tapered Element Oscillating MicroBalance (TEOM) PM samplers are much more expensive, but could be used to develop a body of data that is both accurate and inclusive of operating variability over long periods. The commenter is not aware that any such data was used to inform the development of the PM standard, but contends that this analysis should be performed on the 12% of existing units identified in the development of the PM surrogate for HAP metals.

Response to Comments 44 - 45: As discussed in detail in other sections of this document (see 4F01 responses), the requirement for total PM testing has been removed from the final rule.

14. Miscellaneous comments regarding testing.

Comment 46: Commenters 17621 and 17758 state there is a need to establish test methods that can measure the HAP or surrogates accurately at the actual stack gas concentrations. Commenter 17621 refers to an EPRI study that evaluated whether an accurate measurement could be obtained by most of the ICR laboratories at those emission levels using the standard methods required by the ICR (Appendix B; Method Sensitivity for ICR Data Usage and Compliance with Proposed MACT Limits). The commenter concludes that the method sensitivity is not adequate to quantify HAP or surrogates at many of the new unit limits that EPA is proposing. According to the commenter, the reason for this is that the EPA's floor procedure relied on outliers and did does not take into account method performance with actual stack gas samples.

Comment 47: Commenter 17725 states that in section 63.7520(d), the EPA minimum sampling time of 4 hours for each test method seems excessive for certain pollutants. The commenter recommends that the EPA re-evaluate the required sampling times for each method and/or provide alternative minimum sample volumes for each method, taking into account representative analytical detection limits and emissions standards that are properly adjusted for non-detect values.

Response to Comments 46 - 47: The EPA reviewed the minimum sample volumes required for the emissions limits and, based upon the present analytical capabilities, concluded that the sample volumes specified are appropriate. In the future, facilities with the capabilities to meet the stack detection limits in less than required volumes may request alternative test methods per 63.8(f).

Comment 48: Commenter 17731 states that the proposal to require "total PM and HAP metals testing during the same compliance test period and under the same process (e.g., fuel) and control device operating conditions at least once every 5 years" (citing 76 FR 25029/2), has not been justified given that it is highly unlikely an EGU could demonstrate compliance with the total PM limit while exceeding the individual PM and HAP metals limits.

Response to Comment 48: The final rule will not require testing of both the filterable PM emission limit and the corresponding HAP metals standard. The source will conduct the test that is applicable to the standard with which the source has elected to comply.

Comment 49: Commenter 19033 states that the Table 8 data recording requirements should match the sampling times specified in Table 7. The commenter states that for example, scrubber and ESP parametric data is mandated by Table 7 to be recorded at 15 minute intervals during each test run. Three test runs are then required. According to the commenter, since Table 8 requires that subsequent data is to be maintained in 12-hour block averages, it would seem the EPA wants each test run to last 4 hours. However, the commenter states, as examples, Table 2 specifies that each PM test run needs to collect a minimum of 2 dscm, and each HCl test run using Method 26A needs to collect a minimum of 0.75 dscm. The commenter doubts that it will take 4 hours to meet the minimum test run sample volume for either pollutant and therefore they recommend that Table 8 be amended from 12 hours to the time period required to perform three test runs.

Response to Comment 49: For the 12-hour block average limits discussed in this comment, the EPA notes that the final rule does not require data reporting of these parametric data. Generally, the only operating data reported under the final rule are PM CPMS data (see the final preamble and other responses pertaining to the potential for liquid oil-fired units to require operating parameter data in certain situations). The source will collect hourly data during the performance test, identify the highest hourly average during the test, and then record data during operations on an hourly basis and develop a rolling 30-day average of the PM CPMS data. There is no intent that the 30-day average represent the length of the Method 5 or 29 stack test.

Comment 50: Commenter 18963 states that if the EPA does not agree to revise the proposed rule to provide that if an owner/operator of an affected EGU elects to demonstrate compliance with total non-Hg HAP metals by using the PM surrogate, then such owner/operator is not required to conduct performance tests for PM and total non-Hg HAP simultaneously, the proposed rule must nonetheless be revised to avoid additional ambiguities. Specifically, according to the commenter, the proposed rule lacks clarity related to the requirement to conduct periodic emissions testing for HAP metals and total PM during the same compliance period and under the same process and control device operating conditions (citing76 FR 25,106). According to the commenter, the proposed rule fails to clearly address a facility's compliance status if it simultaneously conducts stack testing for HAP metals and PM during the same compliance period, and demonstrates compliance with the applicable standards for one of these two pollutants.

Response to Comment 50: The final rule has been amended to remove the requirement for testing total non-Hg HAP metals if the source elects to meet the filterable PM standard (and vice versa).

Comment 51: Commenter 18021 states that any performance testing of an EGU needs to be representative of the unit's actual operation. According to the commenter, EGUs ramp up and ramp down based on demand, and the performance testing needs to be based on a test plan that will, in the end, reflect the unit's actual operation. According to the commenter, that unit's specific test plan needs to make it possible to "certify" and have the documentation demonstrating that the EGU configuration, control devices, and material/fuel have remained constant since the prior performance test was conducted (section 63.10005(d)(1)(iii)). According to the commenter, this protocol would be consistent with section 63.1 0007(c). The commenter asserts that the flexibility to address normal operating conditions should be clearer. The commenter provides that if an affected unit chooses to establish limits for PM as a surrogate for metals and if the limit on PM were established based on a one-time test of three runs at maximum potential operating load, the affected source would be penalized at those units where over-controls were provided to allow for a compliance buffer.

Comment 52: Commenter 18015 opposes the proposed requirement for periodic compliance testing for several individual HAP for which the proposed rule designated a single surrogate. The commenter believes that demonstration of continuous compliance for that surrogate based on data collected with CEMS should assure compliance with the requirements for the individual HAP that surrogate represents.

Response to Comments 51 and 52: The agency agrees with the commenter that performance testing should be representative of an EGU's actual operation. For initial short term performance tests (e.g., manual three run tests), the rule specifies that emissions testing is to occur at maximum normal operating loads. The rule also reminds EGU owners or operators of the ability to conduct performance testing at loads other than maximum, in case alternate operating limits for those periods are desired. For the 30 day or other longer term performance testing averaging periods, the final rule does specify a minimum process operation but expects that measured emissions values to represent normal operations. As noted elsewhere in the responses to comments, emissions created during process startup and shutdown are not included in the compliance calculations. All other periods are considered normal process operations during which the emissions limits apply.

The final rule has been amended to remove the requirement for testing for both the HAP and a surrogate. for the final rule provides multiple alternative emissions limits and you will have to demonstrate compliance only with the limit for which you are demonstrating compliance.

Comment 53: Commenter 18015 states that a testing grace period, similar to the 40 CFR part 75 RATA grace period provisions, should be applied when a source is unable to complete the required testing by the deadline specified. Additionally, the commenter recommends that a grace period of 720 unit operating hours should apply to sources that are unable to complete performance tests within the allotted time period.

Response to Comment 53: The EPA agrees with the commenter that a grace period similar to the 40 CFR Part 75 RATA grace period provisions should be provided for RATA testing and these provisions have been added to Appendices A and B. The EPA disagrees that grace period provisions should be provided for the performance testing requirements in subpart UUUUU. The part 63 General Provisions section 63.7(a) provide for an extension of the performance testing deadlines only for situations beyond the source owner/operators control. The provisions for requesting such extensions and the procedures for implementing them are explained in greater detail in the "Clean Air Act National Stack Testing Guidance" released on April 27, 2009.

Comment 54: Commenter 17881 states that clarification is needed with respect to what it means to "conduct all applicable performance tests for PM (or SO_2) and non-Hg HAP metals (or HCl) during the same compliance test period" (citing section 63.10006). According to the commenter, while this statement may make limited sense for those units demonstrating compliance via a CEMS, EGUs relying upon manual sampling methods for the surrogate will not likely be able to conduct concurrent tests for the associated HAP(s) due to limitations on sampling port availability, possible interferences from multiple probes inserted at a given stack plane, etc.

Comment 55: Commenter 17881 questions how, when CEMS are being used to measure the surrogate (i.e., PM or SO_2), one would reconcile a 30-day compliance test period for the surrogate with the relatively short duration run times associated with manual sampling methods for non-Hg metals and HCl (citing section 63.10006).

Response to Comments 54 - 55: In response to comments, the final rule has removed all requirements for duplicative testing of a HAP and a surrogate. Facilities complying with surrogate standard do not have to perform periodic testing for the corresponding HAP.

Comment 56: Commenter 17881 states that as currently written, section 63.10006(e) requires that the fuel factor methodology and equations in sections 12.2 and 12.3 of Method 19 (40 CFR 60, Appendix A-7) be used to convert the results of the performance tests into units of lb/MMBtu of lb/TBtu, as applicable. According to the commenter, this section should recognize that such calculations need not be conducted if an EGU has chosen to demonstrate compliance with the mass per unit of electrical output emission limits.

Response to Comment 56: The final rule has been amended to clarify that only the methodology or equations required for the specific emission limit will be required.

Comment 57: Commenter 17881 states under Table 1 - Emission Limits for New and Reconstructed EGUs, that the run times specified for each constituent should be the lesser of 4 dscm or the duration required to capture a specified amount of PM. According to the commenter, the current volume equates to a run time of about 4 hours at a typical sample rate of 30 dscf/hr.

Response to Comment 57: The EPA does not believe a change is warranted. The run time is that needed to get at least 4 dscm. The commenter's suggestion would not change that because, using the commenter's phrasing the current wording is the same as "the lesser of 4 dscm or the duration required to capture a specified amount of PM [4 dscm]."

Comment 58: Commenter 17881 questions why (under Table 2 - Emission Limits for Existing EGUs, for Coal < 8300 Btu/lb, Total PM) the run time is different than the run time for existing units firing coals > 8300 Btu/lb when the PM emission limit is identical.

Response to Comment 58: The final rule has been amended to fix the clerical error.

Comment 59: Commenter 17881 states that (under Table 5- Performance Stack Testing Requirements for Non-Hg HAP Metals) the exhaust flow and moisture should only need to be determined if you are complying with the lb/MWh limit. According to the commenter, the O_2/CO_2 levels should only need to be determined if complying with the lb/MMBtu standard.

Response to Comment 59: The final rule has been amended to clarify that only the methodology or equations required for the specific emission limit will be required.

Comment 60: Commenter 17881 questions whether (under Table 5, for HCL and HF) 40 CFR part 60, Appendix F, Procedure 1 is really applicable to HCl and HF CEMS.

Response to Comment 60: Based on the comments received that support the use of part 75 reporting for CEMS, we have added an Appendix B to the rule to set the technical requirements for QA applicable to an HCl or HF CEMS if used under this rule. The procedures are largely similar to Appendix F as proposed but adapt those requirements to fit more closely with approaches taken under Part 75 so that the existing reporting infrastructure for Part 75 reporting can be easily adapted to support this rule.

Comment 61: Commenter 17881 states that (under Table 5) 40 CFR part 60, Appendix B, Performance Specification 6 conflicts with the QA requirements in part 63, subpart UUUUU, Appendix A for auxiliary measurements.

Response to Comment 61: The final rule will be amended to provide consistency with Table 5 and Appendix A.

Comment 62: Commenter 17881 states under Table 5, for Hg, (bullet a.) Method 20B (sic) contains alternate provisions for determining the number of sampling points as compared to Method 1.

Response to Comment 62: The final rule has been amended to allow the alternative provisions for sample point selection contained in Method 30B.

Comment 63: Commenter 17881 states that under Table 5, bullet f., the rule should also contain provisions for lb/MWh or lb/GWh conversions.

Response to Comment 63: This issue has been addressed in Table 5 and section 63.10007(e) of the final rule.

Comment 64: Commenter 17881 states that under Table 5, for the LEE testing, moisture and flow should only be required if you elect to show compliance with the lb/GWh limit or calculate annual mass using a flow CEMS, in which case moisture would be needed.

Response to Comment 64: The final rule has been amended to clarify that only the methodology or equations required for the specific emission limit will be required.

Comment 65: Commenter 17681 states that proposed section 63.10011(b)(3)(i) appears to require operators to determine the fuel mixture with the highest content of non-Hg HAP metals and asks if this determination requires distinction between types of coals (i.e., anthracite, bituminous, subbituminous, etc.) and between regions (i.e., Illinois Basin coal vs. Appalachian coal).

Response to Comment 65: The final rule no longer includes this provision.

Comment 66: Several commenters (19536, 19537, 19538) state that the EPA should strengthen monitoring requirements for acid gases because one plausible combination of monitoring and FGD controls is omitted from the proposal. Commenters state that no periodic performance testing and operating parameter monitoring are specified for units that use CEMS but have no controls.

Response to Comment 66: The final rule does not include the control device continuous parametric monitoring of the proposal and replaced that monitoring with greater reliance on CEMS for control acid gases and the PM CPMS for control of HAP metals and filterable PM. The rule also provides the option to use frequent manual performance testing with the premise the frequent testing (e.g., quarterly) will ensure that sources must maintain the process and control technologies in condition consistent with compliance performance on a continuous basis. This includes units that comply with emissions limits with no add on control devices. As for augmenting CEMS data with additional performance testing, we believe that CEMS data verified with periodic quality assurance testing and other quality control measures as required by the rule provide means sufficient to demonstrate compliance with the emissions limit on a continuous basis and independent of additional performance testing.

Comment 67: Commenter 17174 states that the term "maximum normal operating load," as used in section 63.10007, is not defined. According to the commenter, facilities use different fuels in different proportions, depending on many variables such as availability and cost. The commenter asserts that the EPA should provide a clear definition of maximum normal operating load or representative operating conditions in section 63.10042. According to the commenter, the EPA should also clearly define how a source that utilizes more than one fuel should comply with this requirement. The commenter states that there appears to be an inconsistency between the testing conditions specified in section 63.10007(c) and (f). According to the commenter, while section 63.10007(c) requires facilities to conduct performance tests at the "maximum normal operating load," section 63.10007(f) requires facilities to conduct performance tests under such conditions as the EPA Administrator specifies to the owner or operator based on "representative performance" of the affected source for the period being tested. (76 FR 25108)

Comment 68: Commenter 17770 states that there is a problem with setting an emission limit that must be achieved on a continuous basis using results from a periodic performance test. According to the commenter, a performance test is conducted according to prescribed conditions, i.e., steady state, full load conditions and provides a "snap-shot" of unit performance representative of those steady state conditions, and a performance test does not show how that the unit will operate under all conditions and at all levels of unit operation. The commenter states that typically, a unit will operate above or below the load conditions during which performance tests are conducted.

Comment 69: Commenter 18935 notes that the proposed minimum sample volumes for metals and HCl will probably not yield the required detection limits to establish compliance. According to the commenter, while a responsible emission testing firm will make source-specific calculations as part of test planning, the proposed sampling volumes may significantly skew the anticipated cost of and time associated with compliance testing. As a responsible emission testing service provider, the commenter encourages the EPA to present realistic sample volume and duration information so that sources can properly budget and prepare for compliance testing.

Response to Comments 67 - 69: The EPA reviewed, and adjusted as appropriate, the final emission limits and minimum detection levels so that the rule contains appropriate sample volumes and run durations.

Comment 70: Commenter 18021 states that the small degree of alternative requirements with Administrator's approval is built into the regulation but is concisely stated. The commenter requests elaboration in at least the preamble that recognizes the variability in design and operating characteristics of EGUs allowing consideration of alternatives supported with a demonstration during the performance tests is needed. The commenter requests that the EPA allow demonstration with CEMS and/or operating parameters in lieu of an emission test after the annual performance test during the first 2 to 3 years.

Response to Comment 70: While the agency appreciates the commenter's support for rule brevity, the agency does not believe the preamble needs to elaborate on an EGU owner or operator's ability via the general provisions in §63.8(f) to seek an alternate means of monitoring. The agency finds the last comment moot, as the rule no longer requires annual performance tests or operating parameter limits for those EGUs whose owners or operators choose to use CEMS.

5A02 - Testing/Monitoring: Averaging times for monitored pollutants

Commenters: 17621, 17623, 17627, 17638, 17681, 17689, 17702, 17705, 17714, 17716, 17718, 17725, 17730, 17736, 17740, 17757, 17758, 17767, 17774, 17775, 17796, 17798, 17800, 17807, 17820, 17873, 17881, 17885, 17902, 17904, 17909, 17925, 17926, 17927, 17928, 17929, 17930, 18014, 18018, 18034, 18037, 18421, 18443, 18498, 18539, 18644, 18831, 19032, 19041, 19114, 19121, 18023

1. Commenter supporting current or shorter averaging times.

Comment 1: Commenter 17926 supports and offers praise for the proposed averaging times in conducting Hg-related testing. According to the commenter, currently Montana utilizes a 12-month average in calculating the emissions of generating units. The commenter states that while Montana has Hg emissions limitations, the averaging times may allow for emissions spikes of Hg. According to the commenter, the proposed averaging times by the EPA, which are averaged on a rolling basis of 30 boiler operating days, will assure that facilities are adequately complying with emissions limits. The commenter also contends that a 30-day averaging time will help to assure that facilities are avoiding time periods with periodic spikes in emissions.

Response to Comment 1: The agency appreciates the commenter’s support for the rule’s averaging time for Hg.

Comment 2: Commenter 17929 states that compliance with the EPA’s standards for PM and Hg are not to be based on a single triplicate “independent sample” at a single “randomly select[ed] future test condition” where the EPA has claimed it wishes to provide 99 percent confidence, but rather continuous, integrative sampling every minute of every day and then averaging for a long-term, 30-operational-day period. According to the commenter, because the EPA is using a 30-day rolling average rather than a triplicate sample, the various measures that the EPA uses to account for variability in a triplicate sample are irrelevant and unnecessary. The commenter states that there is no rationale for an “n” of 3 test runs in the UPL equation, for an “s2” value, the variance in the single-point emissions data from the top units, or for a student’s t-statistic with a 99% confidence level. The commenter asserts that there is no rationale at all for the whole UPL calculation unless compliance is to be determined solely based on a single triplicate sample, which, the commenter asserts, it is not.

Response to Comment 2: The agency uses a number of statistical tools so that poorly performing or problematic sources can be identified. Basing emissions limits on the average result of three test runs and adjusting that result to account for most, if not all, false positive results, then setting a commensurate averaging time that accounts for brief, transient emissions spikes, focuses the agency’s resources on those poorly performing or problematic sources, instead of penalizing inadvertent occurrences.

Comment 3: Commenter 18421 states that the proposed procedures permit averaging of Hg levels on a rolling 30 boiler operating day basis, which could result in days when a given boiler is exceeding the NESHAP limit for Hg emissions. According to the commenter, the EPA should adjust the procedures for Hg CEMS to ensure continual compliance with the standards of the proposed rule.

Response to Comment 3: The agency disagrees with the commenter, for the procedures for Hg CEMS as well as Hg sorbent traps are designed to ensure continuous compliance with the rule. As mentioned in a previous response, establishing an averaging time that accounts for brief, transient emissions spikes focuses the agency's responses on those poorly performing or problematic sources, instead of penalizing inadvertent occurrences.

Comment 4: Commenter 17975 notes that emission limits for non-Hg metals are based on a 30-day rolling average that would include startups, shutdowns and maintenance events. Commenter 17975 goes on to state that the stack tests upon which the agency's PM standard is based do not reflect emission rates that can be achieved over a 30-day period because stack testing is usually designed to assure compliance with PM limits that must be met over a three-hour period. The commenter asserts that the agency's 2009 "Clean Air Act National Stack Testing Guidance," which applies to both MACT and NSPS, makes clear that stack testing to determine compliance with these short term limits should be conducted under conditions that "are most likely to challenge the emission control measures of the facility with regard to meeting the applicable emission standards."[1] The guidance further explains that stack testing should be conducted when boilers are operating at peak capacity, and using the dirtiest fuel that it can legally burn because stack testing under these conditions is designed to measure the maximum emissions that will occur within any three-hour period over the course of a year or more.[2] The commenter believes that actual emissions averaged over 30 days during periods when units are operating at lower capacity with cleaner fuels – are likely to be much lower.

Response to Comment 4: The comment is moot, as the rule no longer has numeric emissions limits applicable during periods of startup or shutdown.

2. Commenters supporting annual compliance periods rather than 30-day periods.

Comment 5: Numerous commenters (17623, 17627, 17714, 17716, 17736, 17757, 17774, 17800, 17873, 17885, 17902, 17909, 17930, 18018, 18037, 18498, 18831, 19032, 19041, 19114) state that the compliance period should be increased from a 30-day rolling average to a 12-month or 365-day rolling average.

Commenters 17623 and 17774 state that the EPA has authority under the CAA to use discretion to shape compliance periods and averaging times for MACT limits and suggest that the EPA use a 12-month rolling average compliance period rather than the proposed 30-day rolling average period, because a 12-month rolling average still requires compliance reporting every month but helps limit the number of violations resulting from normal seasonal variability in electricity use and associated emissions. Commenter 17774 notes that the EPA has used 12-month rolling averages in a number of other MACTs (e.g., boat manufacturing and magnetic tape).

Response to Comment 5: The agency disagrees with the commenters, noting that for this rule, an averaging period of 30 boiler operating days, as opposed to a 12-month or 365-day rolling average, is sufficient to account for normal variability, as well as other brief, inadvertent occurrences.

3. Support annual averaging due to SSM issues.

Comment 6: Multiple commenters (17714, 17627, 17718, 17757, 17800, 17925, 18831) state that the proposed rule requires utilities to meet emissions limits at all times including periods of startup and shutdown but that the ICR stack testing data did not include startups or shutdowns and that it is inappropriate to establish limits that include startups and shutdowns. Commenters 17714 and 18831

---

[1] EPA, Clean Air Act National Stack Testing Guidance 15, 16 (2009).
[2] Id.

recognize that the proposed 30-day rolling averaging compliance period is likely to be helpful in addressing the variability in emissions during normal operations, but commenters do not believe a 30-day period is sufficient to address inclusion of startup and shutdown emissions. Commenter 17714 states that absent sufficient stack testing data from real operations that include several periods of unit startup and shutdown across the range of units included in the affected source category, the averaging period should be increased to 365 days to accommodate periods of startup and shutdown.

Comment 7: Several commenters (17718, 17627, 17757, 18037, 18539) note that ICR data did not encompass the full range of operating conditions including changes in operating variables (i.e., pulverizers taken out of service, fuel variability causing changes in control equipment operations, etc.) that a unit experiences in the normal course of operation. According to the commenters, the EPA can alleviate some of the effect of variability on unit emissions that was not accounted for in the 2010 ICR testing by allowing annual averaging, while still achieving the same emission reductions.

Comment 8: Commenter 17925 states that while the EPA indicates the 30-day averaging time addresses concerns with startup, shutdown, and malfunction (SSM), according to some utility industry experiences, an unexpected period where more than one startup/shutdown cycle occurs will significantly impact compliance with MACT emission limits. According to the commenter, this is understood by considering the number of hours involved in a startup and the impact of treatment equipment coming to equilibrium with the changing temperatures, gas flow rates and pollutant loadings.

Comment 9: Commenter 17800 states that the utility industry has limited experience with some of the continuous monitoring devices that suggests such spikes can occur and may not be representative of stack gas concentrations. According to the commenter, the EPA should allow reasonable exemptions for startup, shutdown and malfunction conditions or lengthen the 30-day rolling averaging time. The commenter notes that the State of Illinois has adopted a Hg standard that is based on a 12-month rolling average.

Comment 10: Commenter 17736 states that a 30-day rolling average, especially if SSM periods are included, makes compliance nearly impossible. According to the commenter, a few hours of ESP downtime can destroy a 30-day rolling average. The commenter suggests that the use of a 12-month averaging period helps to ensure that compliance results will not be skewed by SSM periods. The commenter states that an annualized averaging period is equally effective in reducing the total emissions as is a 30-day period.

Comment 11: Commenter 17758 states that the EPA's assumption that providing a 30-day averaging period will smooth out any emissions increases associated with infrequent startup and shutdown periods is predicated on infrequent startup and shutdown periods of short duration. According to the commenter, the frequency and duration of startup and shutdown periods varies for different types of units and different fuels. The commenter states that the EPA's assumption that 30-day averaging addresses this is unsupported in the record by data from actual unit operations. Accordingly, asserts the commenter, the EPA has not demonstrated that 30-day averaging will enable affected units to comply with a continuously applied MACT standard.

Comment 12: Commenter 17774 notes that the use of a 12-month rolling average also assists regulated facilities in meeting what are extremely strict standards. For example, the commenter states, one of commenter's PM CEMS is installed on one of the most controlled units in their fleet, which utilizes ESP, wet FGD and SCR technology. According to the commenter, the data from these CEMS (see attachment to EPA-HQ-OAR-2009-0234-17774-A1.pdf) show that this unit will not consistently meet the proposed 30-day rolling average PM limit. The commenter states that although this unit typically operates below the proposed limit, there are numerous events (87 exceedances of a 30-day average in a 2-year time period) where unplanned shutdown/startup events and temporary spikes in PM emissions push the 30-day rolling average above the proposed limit. Similarly, the commenter notes that Hg CEMS, which are installed on two of their most controlled units using ESP, wet FGD, and SCR technology show that these units will not meet, on a consistent basis, the proposed 30-day rolling average Hg limit. (See attachment to EPA-HQ-OAR-2009-0234-17774-A1.pdf.) According to the commenter, while these units usually operate below the proposed limit, there are a number of events (93 exceedances of a 30- day average in a 2-year period) where unplanned startup/shutdown events and unpredictable short term spikes in Hg emissions push the 30-day rolling average above the proposed limit. It is commenter's experience that the cause of these Hg spikes cannot be attributed to any particular operating parameter or fuel characteristic that the commenter can reasonably control. The commenter supports a 12-month rolling average to allow for flexibility in compliance by accommodating unplanned startup/shutdown events and inevitable spikes in emissions while maintaining a high level of environmental integrity. According to the commenter, it also will help to limit noncompliance, and therefore promote overall adherence to the rule. The commenter asserts that such flexibility will assist in alleviating the very high burden imposed by the proposed Utility MACT.

Comment 13: Commenter 17873 states that averaging time is important in dealing with non-steady state operations and emissions during these periods should either excluded from the compliance determination, or the averaging period should be lengthened from a 30-day average to a 12-month rolling average, calculated monthly. The commenter offers an example of the practical importance of a longer averaging period when in 2007, Xcel Energy upgraded the Allen S. King Generating ("King") Plant. The commenter states that this upgrade included the installation of new pollution control equipment, modification of the plant heat rejection system, and improvements to the boiler and that the new control equipment consisted of a SCR reactor for NO_X control, a spray dryer absorber lime-based, FGD system for SO_2 control, and a pulse-jet cleaned fabric filter for additional PM control. According to the commenter, the cyclone-fired boiler burns subbituminous coal and is considered to have BDT equipment installed, and the King Plant's SCR and FGD systems require specific flue gas temperatures and the boiler to be at specific steam pressures in order to operate properly. According to the commenter, given this, King cannot operate the SCR and FGD during periods of startup when flue gas temperatures and steam pressures are lower than required. The commenter states that the plant's current permit limits require compliance based on lb/MMbtu of SO_2 and NO_X using a 30-day rolling average, and the commenter's experience provides strong evidence of the difficult many units will have in meeting emission units using that averaging approach. At King, the commenter found that permit limits can be met if there is only a single start-up within a given 30-day period, but additional start-ups significantly jeopardize compliance for both SO_2 and NO_X. According to the commenter, it is not uncommon for King and other similar units to experience more than one start-up within 30 days in cases of forced outages and even planned maintenance. The commenter states that it is unrealistic and unreasonable to require compliance with the proposed Hg, HCl, and PM limits on a 30-day rolling average basis.

Comment 14: Commenter 17904 notes that even one of its best performing units (Oak Grove Unit 1), a well-controlled unit, would likely not be able to achieve 100 percent compliance. According to the commenter, this is because the EPA's proposed standards have been set too stringently, even for these units that were put into commercial operation since 2009 and are equipped with the most advanced, commercially available controls. According to the commenter, operating conditions and fuel quality can vary over short time periods, and periods of startup and shutdown can also affect emission rates over short time periods. The commenter urges the EPA to establish longer averaging times to smooth out this variability. The commenter notes that the EPA has previously explained in response to interagency comments that its concern with a longer averaging period is that EGU owners may overspend on Hg control as the result of over-injection of sorbent or lack of sufficient maintenance. According to the commenter, apparently the EPA believes this would increase owner or operator risk of non-compliance and liability associated with non-compliance, because owners and operators would decide to only check control devices once per year. However, the commenter states the length of the compliance period is extremely unlikely to drive behavior that is not optimal for owner or operator control of emissions and costs. According to the commenter, it is in the best interest of these parties to both minimize the cost of control and to maintain compliance. Thus, the commenter states that the EPA's argument against an annual averaging period is not persuasive. According to the commenter, importantly, longer averaging times would simply help redress the variability issues. The commenter asserts that the EPA would only create the same variability problems if it promulgated standards with longer averaging times but at the same time applied its UPL variability analysis to set a lower numerical emissions rate.

Comment 15: Commenter 17774 states that despite the EPA's statements in the preamble that it will provide a measure of leniency with regard to instances of malfunction, they have serious concerns about the attendant uncertainty regarding how affected sources may be penalized. According to the commenter, in addition, even with a promise of reasonableness from the EPA, regulated entities could still be vulnerable to citizen suits. Although the commenter supports the EPA's proposal that not all malfunction events would necessarily result in a violation the commenter asserts that regulated facilities would still be subject to significant EPA and state discretion concerning such occurrences and would be forced to shoulder the burden of proving an affirmative defense. According to the commenter, these requirements distract from efficiently reducing emissions consistent with the EPA policy and as such, are not an acceptable approach to periods of malfunction.

Comment 16: Commenter 19121 states that it appears that the compliance averaging time for operational limits is substantially more stringent than for the numerical emissions limitations set under the proposed rule. According to the commenter, this will have the effect of further limiting operational flexibility. It will also negate the effect of blending in startup/shutdown events so that MACT limits can be met. The commenter states that although a given numerical limit could be met on a 30 boiler-operating day average, operating limits could not be met on 1-hour, 4-hour, or 12-hour periods blending the same events. According to the commenter, continuous compliance should be shown based upon emissions monitoring only.

Comment 17: Commenter 17740 states that the EPA's conclusion that EGUs "do not normally startup and shutdown frequently" effectively, and incorrectly, assumes that all units are operated as base load units. As the Seventh Circuit recognized in *United States v. Cinergy*, "[u]tilities operate power generation equipment in three general ways: baseload, cycling, and peaking." 623 F.3d 455, 459 (7th Cir. 2010). According to the commenter, non-baseload units start up and shut down frequently, and even supposed "base load units" are often, and unpredictably, shut down for unit "trips" (i.e., unplanned outages). The commenter asserts that the EPA further assumes that basing the proposed standards on a 30-day rolling average will account for any increased emissions during periods of startup and shutdown and that the EPA made a same faulty assumption in the proposed rule that preceded the Boiler MACT, *see* 75 FR 32,012-13, and rejected it in the final rule, *see* 76 FR 15,642. According to the commenter, the EPA has not demonstrated that the 30-day rolling average will address the substantial operating variations among EGUs or even within an EGU. While a number of the MACT pool EGUs are newer, well controlled, baseload units, the commenter asserts that the EPA cannot assume that the entire universe of coal-fired EGUs, even baseload units, will operate as reliably as newer units. According to the commenter, as EGUs age, they tend to experience more forced outages than when they were newly constructed; thus, an older EGU with highly efficient controls may not be able to meet a 30-day standard in months in which it experiences a number of forced outages.

Response to Comments 6 - 17: The final rule established work practices for periods of startup and shutdown, which addresses this concern about the impact of such periods on compliance with a 30-day rolling average. See the preamble discussion for further detail on EPA's rationale for excluding startup and shutdown periods from calculating compliance with the emission limits in the final rule. For malfunctions, EPA provides an affirmative defense for exceedances that may be caused by such events. With these provisions, EPA believes that the concerns raised in these comments are appropriately addressed without modifying the general use of 30-day rolling averages for this rule. See also preamble and response to comments below explaining EPA's approach to malfunctions. With respect to the one comment about the proposed operating parameter limits being based on a shorter time period, those comments are now moot given the lack of operating parameter limits with 12-hour or similar averaging periods specified in the final rule.

4. Supporting longer averaging time due to health outcomes.

Comment 18: Several commenters (17716, 17725, 18014, 18498) state that a 30-day rolling average compliance period is inconsistent with health effects and that the EPA has presented insufficient findings related to the prerequisites for reaching an "appropriate and necessary" determination for regulating EGUs under CAA section 112(n)(1)(A). Several commenters (17716, 17725, 18498) state that even if one accepts the EPA's explanation of the potential hazards of the relevant HAP, that explanation does not justify compliance on a rolling 30-day basis because no exceedances of HCl, HF or HCN standards were documented in the 1998 Utility HAP Report to Congress and no hazards to public health have been established based on HAP emissions from EGUs. Commenter 17716 takes exception to the EPA's direction of attention to alleged potential hazards that might result from long-term cumulative exposure in the absence of any short-term exposure concerns associated with emissions from EGUs because, according to the commenter, nothing has been shown to suggest a hazard from 30-day exposure to current EGU HAP emissions, and in these circumstances, the value of monthly testing is neither apparent nor warranted to protect against a cognizable risk. Commenter 17716 goes on to state that absent a showing of need or benefit for monthly testing, yearly testing should be applied as providing the requisite level of protection against the inchoate long-term potential risks alleged to be involved."

Comment 19: Multiple commenters (17627, 17757, 18498, 18539; 18644, 19032, 19041, 19114) state that the EPA has not demonstrated why a 30-day averaging period would be more protective to human health than an annual period, particularly for Hg emissions, where mass emissions are the key issue. Commenter 17725 states that no short-term exposure concerns associated with the ambient level contributions from EGU. According to the commenter, if any risk exists at all, the EPA can only suggest that they are related to chronic, long-term exposure or related bioaccumulation manifesting over years; thus, if the emissions from a source are a little higher one month due to a control upset but are then offset by lower emissions during the next month(s), the health impact would be essentially identical to a source with no "ups and downs" in the monthly emissions but with the same annual emissions.

Comment 20: Multiple commenters (17716. 17689, 17702, 17718, 17798, 17885, 18037, 18443) state that the risk and concern expressed by the EPA centered around long term emissions (e.g., bioaccumulations) and that therefore the use of a rolling average that would need to be calculated every day is unwarranted. Commenters suggest that compliance should only be assessed on an annual basis and this would still produce the same control and environmental outcome. Commenter 17798 states that the EPA should distinguish and structure requirements based on whether the hazardous pollutant creates acute or accumulative impacts. For example, according to the commenter, acid gases are of concern for even very short periods of exposure whereas for metals, including Hg, the impacts are more related to the total loading and accumulation in the environment.

Response to Comments 18 - 20: The EPA establishes the limits based on the maximum achievable control technology, not the specific timeframe over which health risks from the applicable hazardous air pollutants may manifest themselves. The monitoring and testing provisions are established to ensure continuous compliance with those standards. The EPA believes that the final rule's monitoring and testing provisions provide a cost-effective means of ensuring continuous compliance with the standards, and take advantage of a range of options, with significantly reduced monitoring and testing where the margin of compliance indicates a reduced likelihood for potential noncompliance situations.

Comment 21: Several commenters (17716, 17725, 18014, 18498) suggest the use of block averages for PM, Hg, and HCl CEMS data as performance indicators, not as direct measures of compliance.

Response to Comment 21: An Hg CEMS and an HCl CEMS are options for use as the performance test method for the applicable Hg and HCl emission limits. If a source is concerned about the use of these methods in such a manner, the rule provides for other options (sorbent trap monitoring for Hg and stack testing for Hg and Cl). There is no use of a PM CEMS as a direct performance test method for the PM emission limit. The PM CPMS is used as an operating parameter monitoring approach to demonstrate compliance with a site-specific operating limit expressed in terms of the raw output of the PM CPMS. The operating limit aids in ensuring that the source is operated and maintained in accordance with good air pollution control practices to minimize emissions so that the source can continue to operate in compliance with the emission limit as demonstrated in a periodic stack test.

Comment 22: Several commenters (17689, 17885, 17930, 18443, 19032) support an annual average because most utilities will be using a sorbent trap because Hg CEMS technology is not likely to yield accurate and precise measurements. According to the commenters, sorbent traps have approximately 2-week collection intervals, so should a problem develop with one sample, 30-day compliance demonstrations would be extremely problematic. Further, asserts the commenter, as the EPA is well aware, a major factor in Hg emissions concentration is the Hg fuel content, so it is quite possible the Hg content variability in coal utilized over a 30-day period could determine non-compliance regardless of best efforts of a utility to limit Hg emissions. Commenter 17930 states that Hg peaks are often experienced month-to-month and the current rule should revise the averaging time to annual to account for this variability.

Response to Comment 22: The agency believes a number of Hg CEMS will be able to provide continuous data regarding mercury emissions; should an owner or operator choose to use sorbent traps in lieu of Hg CEMS, such an owner or operator will be able to use his knowledge regarding process, mercury fuel content, and control device operation to tailor the time the sorbent traps collect samples. Note that sorbent traps are allowed a maximum sample time of 15, not 30, days.

5. CEMS uncertainty.

Comment 23: Several commenters (17725, 18014, 18498) state that in reviewing the CEMS data for compliance purposes, the EPA would need to take into account the uncertainty of the measurements along with the emissions reported for other months.

Response to Comment 23: The CEMS data will be quality-assured in accordance with the rule requirements. Provided the monitoring systems are producing valid, quality-assured data, EPA will use all such data in determining compliance with the emission limits monitored by such a device, in the same manner as any other performance test data may be used. These principles have been in use by EPA since first promulgating CEMS QA provisions in Appendix F to part 60 in the 1980s. The data under this rule will be treated in accordance with those longstanding principles and regulatory provisions.

6. 30-day rolling average is inappropriate.

Comment 24: Several commenters (17705, 17716, 17725, 18014) state that the 30-day rolling average is also inappropriate because it repeatedly penalizes sources for a single emission controls upset because if a source experiences very high emissions one day (startup, shutdown, or malfunction) that single day will affect the 30-day average calculated not only for that day, but also the calculated averages for the next 29 days). Several commenters (17725, 18014, 18498) refer to this situation as not only double jeopardy but thirty-fold jeopardy. Commenter 17800 states that due to the stringency of the proposed standards and the measurement methods required (CEMS and/or emission testing) a short term variation in the process could result in a source being out of compliance for a significant period of time. According to the commenter, one high magnitude but short duration spike in emissions will impact the 30-day rolling average for an extended period of time even if a source takes immediate corrective action.

Response to Comment 24: The final rule includes a work practice in lieu of numerical limits to apply during periods of startup and shutdown. The scenario the commenter raises relative to startup and shutdown emissions inordinately affecting the 30 day average should be moot. The rule also includes provisions for the source owner to apply for an affirmative defense of excess emissions that occur during malfunctions. We believe that the rule addresses these comments such that the source owner has the flexibility to manage process and control device operations in a timely fashion relative to the averaging time of the standards. See also response to Comments 6 through 17, above.

7. Support annual fuel variability.

Comment 25: Several commenters (17702, 17725, 17930, 18018, 18644) state that a 30-day rolling average for compliance may be unworkable for some units and is unnecessarily restrictive. The commenters state that many coal-fired EGUs are designed to bum a variety of coal types. According to the commenters, trace chemical constituents (metal, sulfur, halogen, Hg, chlorine) of coals from the same source can vary significantly. The commenters assert that in certain cases, variations in chlorine content in a coal may mean the difference between compliance and noncompliance with the EPA’s proposed air toxics rule.

Response to Comment 25: As the rule no longer contains fuel content metals or acid gas operating limits but maintains the UPL calculations to account for variability, as discussed elsewhere, the agency believes a 30 boiler operating day rolling average will be sufficient to account for normal variation in fuels for sources that use a CEMS to demonstrate compliance with the standards in the final rule.

Comment 26: Commenter 18443 states that a major factor in Hg emissions concentration is the Hg fuel content. According to the commenter, the currently proposed Hg limit does not account for the variability of Hg in the fuel or varied plant operations and draws only on 40 hand-picked best performing units, and it is possible that the Hg content in a particular coal shipment could be high enough over a 30-day period to exceed the Hg limit despite the best efforts of a utility to limit Hg emissions.

Response to Comment 26: The agency disagrees with the commenter and notes that the Hg emissions limit was established using data from the best performing sources that were adjusted statistically using the UPL procedure to account for variability. Properly maintained and operated Hg control devices should enable source owners or operators to meet the rule's Hg emissions limit.

8. Suggested alternative compliance approaches.

Comment 27: Commenters 17928 and 18644 state that the 30-day averaging time is too short to account for transient events (startup, shutdown and upset conditions), and variability of CEMS data. In order to facilitate the practical use of facility averaging provisions outlined in the proposal, the commenters recommend that a minimum 90-day averaging time be considered, to account for uncontrollable events and emissions variability. Commenter 17928 notes that there has been little real world experience with HCl, PM and Hg CEMS data in general with EGUs and with the lower measurement levels that will be needed to demonstrate compliance. The commenter is concerned that the proposed averaging time may not be long enough to be useful for a facility averaging plan, since an extended maintenance outage of the over-controlled units at a facility could force the other units in an averaging plan to be out of compliance.

Response to Comment 27: See response to Comments 6 through 17 and 24, above.

Comment 28: Commenter 19121 encourages the EPA to reconsider increasing either the averaging time for limits or the actual PM or Hg limits. According to the commenter, based on recent testing, the commenter's unit is proven to be one of the lowest emitters of Hg in the nation. The commenter notes that the State of Utah has set a Hg limit that is more strict than that the EPA is proposing but that the State rule requires an annual averaging period. According to the commenter, this is an example of balance between limits and limits averaging that would still be protective of human health and the environment, and meet the requirements of NESHAPS.

Response to Comment 28: As mentioned in earlier responses, the agency believes the rule's averaging time appropriately accounts for brief, transient emissions spikes enabling the agency to focus its response on poor performing or problematic sources, instead of penalizing inadvertent occurrences. Given that the commenter's EGU appears to meet a more stringent state Hg standard, it should have no problem meeting the standard contained in the rule.

9. Requests for clarification/explanation.

Comment 29: Commenter 17638 urges the EPA to clarify that a "30 operating day rolling average" is determined by averaging all applicable hours in the 30-day period. According to the commenter, in some cases, the proposed rule appears to indicate that a new daily average would be calculated each day and then 30 daily averages would be averaged to determine the 30-day average, while other language appears to indicate that all of the hourly emissions for the preceding 30 boiler operating days would be averaged to determine the 30-day rolling average. According to the commenter, defining a 30-day period based on daily averages is not fair to units that frequently cycle on and off and could weight a 15-minute period equally to a 24-hour period.

Response to Comment 29: The final rule clarifies that the average is based on all valid hourly averages during each 30-day rolling average period. Hourly averages are not summed to a daily average as an intermediate data value for purposes of determining each 30 boiler operating day average.

Comment 30: Commenter 18034 states that the rule must be revised to provide for proper calculation of emissions during a malfunction. The commenter observes that section 63.10005(l) only applies to startup and shutdown operations. According to the commenter, if power production during a malfunction approaches zero, calculated output-based emissions will spike exponentially. The commenter states that any malfunction causing power production to cease completely for more than an hour while the boiler is in operation will result in the calculated emissions becoming infinite for that hour as will the calculated rolling average that includes that hour and that the 30 boiler operating day average does not address this issue, because Appendix A, Section 6 (76 FR 25144), Equation A-4 requires Hg emissions to be calculated on an hourly basis before calculating the 30 boiler operating day average according to Equation A-5. According to the commenter, this issue does not appear limited to Hg emission calculations, as proposed section 63.10010 requires that the 30-boiler-operating-day rolling average for other pollutants be determined as the average of all the hourly emissions data for the preceding 30 boiler operating days. The commenter indicates that the proposed rule does not appear to contemplate malfunctions in the power production side of a facility and under some circumstances require sources to divide by zero when calculating emissions.

The commenter suggests that the calculation for compliance with the 30 boiler operating day average for the proposed NESHAP rule could be revised to be consistent with how the EPA has proposed demonstrating compliance with proposed revision to 40 CFR 60 subpart Da, i.e., the sum total emissions for the 30 boiler operating days divided by the sum total output over the 30 boiler operating days. According to the commenter, as the EPA has proposed the rule, sources would be automatically in violation of the rule for even miniscule emission rates during a malfunction in which power production ceased for more than an hour.

Commenter 17755 states that a boiler is a separate unit from the generator and can be operated independently, and the boiler units can and do combust fuel without producing electricity (i.e., during SSM and maintenance periods). The commenter notes that the emission limits in lb/MWh could only apply when the generator is producing electricity (MWh), that if not producing electricity then the MWh would be zero and would produce an invalid lb/MWh ratio, and that most excess emissions occur during SSM and maintenance when generator is not operating, and the commenter questions whether emissions that occur when the generator is not producing electricity would be unregulated for these new sources.

Response to Comment 30: Sources are required to comply with the standards at all time, including periods of malfunction. To the extent a source experiences a malfunction that causes the boiler to shut down, the emissions during that period must be included in the 30-day averaging period and, if the malfunction causes the source to exceed the limit for the applicable 30-day averaging period, the source is in noncompliance and subject to penalties unless the source demonstrates that the affirmative defense applies.

The commenter is correct that it may not be possible to demonstrate compliance with the output-based emissions standards under the scenario outlined above. We do not agree, however, that a source would automatically be in violation of the standards because the source could demonstrate that during those periods the source was meeting the applicable input-based standard contained in the final rule. An existing source complying with the output-based limits during periods of normal operation would have to demonstrate that it complied with the applicable input-based standards during the malfunction event.

The source will need to include in its malfunction report the additional calculations and an explanation to demonstrate that the source complied with the standard notwithstanding the malfunction event. Sources complying with the input-based limit would not have to take additional steps to demonstrate compliance during the malfunction event. For these reasons, we are not amending the final rule in the manner suggested by the commenter.

Comment 31: Commenter 17705 recommends that the final rule define "boiler operating day" as a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours to ensure that compliance is always based on at least 720 hours of operation. Commenter 17705 contends that the EPA should specify a minimum number of operating hours necessary to calculate a 30-day rolling average; if the requisite number of hours is not obtained, the EGU should have the option of combining data from that period with the data from the next 30 boiler operating day period until the requisite number of hours is obtained. According to the commenter, the EPA specified a similar procedure in the 40 CFR Part 60, subpart Da provisions for calculation of a 24-hour average in section 60.48Da(g)(3), which requires a minimum number of valid hours to calculate an average.

Response to Comment 31: The EPA disagrees. See responses to comments under Comment Code 5A12 of this document for further discussion on data availability.

Comment 32: Commenters 17740 and 17767 request the EPA to provide clarification to address the following factors: 1) the number of valid data points or minutes required for a valid operating hour, 2) the number of valid data points or minutes required for a valid operating day, and 3) the number of valid data points required for a valid 30-day average.

Response to Comment 32: Section 63.8(g)(2) provides the general rules for hourly averages for all CEMS. There is no minimum for a valid operating day, as an operating day is a day in which fuel is combusted and is not dependent on obtaining valid monitoring data in that day. There is no minimum number of data points for a 30-day average. See responses to comments under Comment Code 5A12 of this document for further discussion on data availability.

Comment 33: Commenter 18023 requests clarification with respect to the method to calculate the 30 operating day rolling average. According to the commenter, in some cases, the proposed rule appears to indicate that a new daily average would be calculated each day and then 30 daily averages would be averaged to determine the 30-day average, while other language appears to indicate that all the hourly emissions for the preceding 30 boiler operating days would be averaged to determine the 30-day rolling average. The commenter provides some examples of their confusion, and asserts that:

- Table 8 in the proposed rule suggests that the 30-day rolling average is calculated as the average of 30 individual boiler operating day values (Proposed Table 8 (7.b) (convert "hourly emissions concentrations to 30 boiler operating mg/dscm values").

- Proposed section 63.10010(g)(5), however, specifies that a 30 boiler operating day rolling average is calculated as "the average of all of the hourly particulate emissions data for the preceding 30 boiler operating days." 76 FR 25,112.

According to the commenter, several other references, e.g., 76 FR 25,097, 25,111, suggest that the EPA intends the 30 boiler operating day rolling average to be based on all the hours in a 30-day period rather than the 30 daily averages. The commenter urges the EPA to clarify that a 30 boiler operating day is based on the average of all applicable hours in the 30-day period. According to the commenter, finalizing the rule based on the average of 30 daily averages would be challenging if the unit frequently cycles on and off, and further, the daily averaging approach would not be fair because it would weight a 15-minute period (*i.e.*, one boiler operating day) as being equal to a 24-hour period (*i.e.*, also one boiler operating day).

Response to Comment 33: The final rule clarifies that the average is based on all valid hourly averages during each 30-day rolling average period. Hourly averages are not summed to a daily average as an intermediate data value for purposes of determining each 30 boiler operating day average.

Comment 34: Commenter 17927 requests clarification of the averaging periods which will be used to demonstrate continuous compliance with the applicable emission limits in the proposed rule.

Response to Comment 34: Averaging periods apply for emission limits where a CEMS is used to determine compliance and for the sole remaining operating limit where a PM CPMS is used. In these situations, the final rule uses a consistent 30 boiler operating day rolling average, based on all valid hourly averages during each successive rolling 30 operating day period.

Comment 35: Commenter 17681 states that section 63.10031(d)(2) of the proposed rule appears to require a description of the deviation in the compliance report. Commenter 17681 asks for clarification of when compliance is determined within the proposed 30-day compliance period; the commenter asks "If an event occurred on December 31 and the 30-day average starting on December 31 and ending on January 30, would that deviation be required to be reported in the January 31 compliance report? And if so, how would a facility know that such an event would deviate from the 30-day average until the end of that 30-day averaging period unless the deviation was extreme?"

Commenter 17730 notes that the EPA has proposed a new averaging time for the emission standards as a 30 boiler operating day average which appears to be different than the historical use of the 30-day rolling average and requests that the EPA provide an explanation of why the EPA is seeking to change the manner in which the averaging times for emission standards have historically been calculated at EGUs. Commenter 17730 believes that the EPA should not impose a more restrictive averaging time for the proposed emission standards.

Response to Comment 35: The rolling average uses a 30-day rolling period as calculated at the end of each successive operating day, based on all valid hourly averages in the preceding 30 boiler operating days. In terms of reporting, a deviation that occurs in January would not be included in the report that must be submitted by the end of January, as that report covers the time period of July 1-December 31. The agency disagrees with the commenter's view that a 30-boiler operating day rolling average is inconsistent with historical averaging times for this industry. For example, the new source performance standard, subpart Da for electric utility steam generating units in existence for over 30 years, uses 30 boiler operating days for the rolling emissions averaging period.

Comment 36: Commenter 17775 states that once the operating limit is established, proposed section 63.10010(g)(5) specifies that a 30 boiler operating day rolling average is calculated as "the average of all of the hourly particulate emissions data for the preceding 30 boiler operating days" (citing 76 FR 25,112/2). According to the commenter, proposed Table 8, on the other hand, suggests that the 30-day rolling average is calculated as the average of 30 individual boiler operating day values (citing proposed Table 8 (7.b) (convert "hourly emissions concentrations to 30 boiler operating mg/dscm values")). According to the commenter, calculating and averaging separate boiler operating day values would make the limit much more stringent for any period that includes a startup or shutdown. According to the commenter, regardless of which the EPA intended to propose, neither has been sufficiently supported.

Response to Comment 36: The final rule clarifies that the 30-day average is based on all valid hourly averages from the PM CPMS in the preceding 30 boiler operating days, with no intermediate daily values used to determine the 30-day average. The agency disagrees with the commenter's suggestion that the 30-boiler operating day rolling average period lacks sufficient support; use of a 30-boiler operating day rolling average period data management during startup and shutdown periods are discussed elsewhere in this document.

Comment 37: Commenter 17796 suggests that the Hg compliance metric be stated succinctly in section 63.10010(f). According to the commenter, it is clearly stated in section 63.10010(g)(5) that compliance is based upon a 30-day rolling average emissions rate on a daily basis. However, the commenter was unable to find this language for the Hg compliance limit for CEMS. The commenter asserts that Section 63.10010(f) refers the reader to Appendix A, but Appendix A does not state the compliance metric.

Response to Comment 37: See Section 6 of Appendix A to the final rule for the calculation procedures.

Comment 38: Commenter 17807 states that the rule proposes to use heat-input-weighted emission limits based a 30-day rolling average. According to the commenter, the rule is not clear on how to calculate the 30-day rolling averages. The commenter proposes calculating a daily total for each constituent, summing the mass and heat input and then calculating the rolling average.

Response to Comment 38: The final rule clarifies that the average is based on all valid hourly averages during each 30-day rolling average period. Hourly averages are not summed to a daily average as an intermediate data value for purposes of determining each 30 boiler operating day average. See also Section 6 of Appendix A to the final rule for Hg calculation procedures.

Comment 39: Commenter 17820 states that the 30-day rolling average limits should contain at least 30 full days of operation.

Response to Comment 39: The EPA disagrees. A boiler operating day is a day in which any fuel is combusted, and each such day is a day for purposes of calculating the average.

Comment 40: Commenter 18014 states that Table 8 requires the source is to convert "hourly emissions concentrations to 30 boiler operating mg/dscm values," which suggests that compliance is assess based on the average of 30 individual daily values. However, according to the commenter, section 63.10010(g)(5) states that 30-day rolling average is calculated as "the average of all of the hourly particulate emissions data for the preceding 30 boiler operating days."

Response to Comment 40: See response to Comment 33, above.

Comment 41: Commenter 18023 requests clarification on the averaging times for operational parameters. According to the commenter, the EPA has provided four inconsistent descriptions as to how the operational parameter limits would be set (*i.e.*, 90 percent of the test average, the lowest 1-hour average, the 12-hour block average, and the average of three minimum values). According to the commenter, the electric utility and industry has no way of knowing which of the definitions the EPA intended to propose. According to the commenter, the EPA must adopt a definition that provides sufficient flexibility to account for changes in unit operations. The commenter states that the average of three runs and the lowest 1-hour average are clearly unreasonable because, by definition, there will be values during the testing that are above and below the average and, on a longer term basis, these values may vary even more.

Response to Comment 41: See response to Comment 36 above for the only remaining operational parameter that applies under the final rule.

10. Rule language corrections.

Comment 42: Commenter 17775 believes that the reference to the 30 boiler operating day compliance period for PM in proposed Table 8 (7.b) is inconsistent with the reference in proposed section 63.10010(g)(5) because proposed Table 8 (7.b) suggests that only 30 daily values are averaged while section 63.10010(g)(5) indicates that up to 720 hourly values are averaged. Commenter 17775 believes that calculating and averaging separate boiler operating day values would make the limit much more stringent for any period that includes a startup or shutdown and concludes that "[R]egardless of which EPA intended to propose, neither has been sufficiently supported. "

Response to Comment 42: The final rule clarifies this issue; see response to Comment 33, above.

Comment 43: Commenter 17638 requests a mass-based alternative compliance option by converting the existing rate-limit (pounds per million Btu) to a mass-limit (pounds per hour with an annual average), based on the unit's permitted heat input. The commenter notes that Florida has recent positive experience in utilizing mass-based limits in permits, achieving substantial environmental benefits while lessening the burden on the source. According to the commenter, the EPA also has extensive experience developing NESHAP compliance requirements on a mass basis, having promulgated at least six such regulations (40 CFR part 63, subparts MMM, XXX, GGGGG, GGGGGG, LLLLLL, and NNNNNN). The commenter further notes that mass rate were used in the modeling supporting the rule and well as in setting the standards (using stack tests date).

Response to Comment 43: While the EPA appreciates the suggested alternative, we have not conducted analyses to assess what specific limits would be necessary to meet MACT statutory requirements under this alternative scenario and believe that the proposed format provides an adequate means of limiting emissions in accordance with the statutory provisions and in such a way as can be monitored and tested for compliance. Thus, the EPA does not believe this type of alternative is necessary or supported at this time.

Comment 44: Commenter 17881 believes that Equation 5 may not always yield an accurate 12-month rolling average emission rate when there is a large disparity in the total monthly heat input (or steam output) across all units included in the averaging plan. According to the commenter, specifically, Equation 5 gives each monthly average emission rate used to calculate the 12-month rolling total an equal weighting (i.e., 1/12, or 8.33 percent). The commenter suggests that it would be more accurate if the 12-month rolling average emission rate was calculated as follows:

Where, Eavg	=	12-month rolling average emissions rate (lb/MMBtu heat input; lb/TBtu for Hg).
Er_i	=	Average weighted emission level for month i for PM, HCl, HF, non-Hg HAP metals or Hg, in units of lb/MMBtu (lb/TBtu for Hg) of heat input, calculated consistent with 63.10009(f)(1).
Hb_i	=	Total heat input for all units included in the averaging plan for month I, in units of

		MMBtu.

Response to Comment 44: The rule replaces a 12-month rolling average with a quarterly weighted average. As the monthly weighted average (ER_i) already makes the adjustment suggested by the commenter, per Equation 3 or Equation 4, the agency sees no reason for keeping Equation 5, so it has been removed from the rule.

Comment 45: Commenter 17881 requests clarification, with respect to Equations 1-5, as to the value of "Er" in those cases where the "performance test" consists of the use of a CEMS to determine a 30-day rolling average emission rate. According to the commenter, as 30-day rolling averages at the end of a given month could include several days worth of data from prior months (assuming that operation is not continuous), there is a high degree of likelihood that the 30-day rolling average emission rate at the end of a month will not line up with the associated calendar month, thereby introducing a disconnect between the average emission rate and heat input value used for weighting purposes. The commenter states that Equations 1 – 4 should specify procedures for reducing CEMS data into average values for purposes of the "Er" term. The commenter suggests a simplistic approach would be to average all valid 1-hour emission rates determined during each calendar month for purposes of Equations 3 and 4.

Response to Comment 45: The final rule includes clarification of the emissions averaging procedures and calculations to be consistent with calculating compliance with the 30 boiler operating day average for emissions rates elsewhere in the rule. The revised procedure also allows for using CEMS data in combination or in lieu of performance testing data for determining compliance with the emissions limits.

Comment 46: Commenter 17621 states that individual measurements that comprise the baseline data pool are incompatible with anticipated compliance measurements. According to the commenter, the EPA approach (as stated on FR 25041) to calculation of a UPL is based on an average of three compliance test runs, each of which follows the underlying measurement protocol that was used for the component baseline data. According to the commenter, compliance options in the proposal typically are at variance with this requirement. The commenter asserts that most require compliance to be determined on a 30-day rolling average using a CEMS. According to the commenter, it should be realized that the statistical properties of these two monitoring approaches are different. (See statistical study provided in Appendix D.)

Response to Comment 46: The commenter appears to confuse the agency's standard setting activities (that include UPL calculations) with collection of CEMS data. The compliance options that rely on use of a 30 boiler operating day rolling average are not at odds with the statistical approach for determining the emissions limit. Use of the statistical approach provides a tangible measure of variability that is a component of the emissions limit, while use of CEMS supplies data that for well-operated EGUs are expected to be equivalent or less than the emissions limit 99 of 100 times. As mentioned in earlier responses, establishing an emissions limit in this fashion allows the agency to focus on the poorly operated or problematic EGUs.

5A03 - Testing/Monitoring: Fuel analysis methods

Commenters: 17316, 17386, 17402, 17621, 17715, 17718, 17722, 17725, 17730, 17731, 17754, 17758, 17760, 17775, 17781, 17796, 17800, 17801, 17807, 17808, 17816, 17820, 17821, 17881, 17902, 18014, 18015, 18025, 18428, 18447, 18483, 18498, 19033, 19114, 19121, 19536, 19537, 19538

1. Exempt natural gas.

Comment 1: Commenters 17316 and 17386 request that the EPA exempt the fuel analysis of natural gas for dual fuel-fired units that fire gas. According to the commenters, in particular, in sections 63.10005(c)(1) and (2), and 63.10006(s), the provisions requiring a fuel analysis for "each type of fuel burned" should explicitly exclude pipeline natural gas. The commenters state that the exemption should be based on natural-gas-fired units being both insignificant source of HAP and otherwise being exempt from the rule. The commenters also suggest that section 63.10005(c)(4), which provides an exemption from the performance of an initial fuel analyses if a unit burns a single fuel type, be extended to exemption any unit which burns only one fuel type, aside from pipeline natural gas (i.e., burns 2 fuel types, but one is pipeline natural gas).

2. Initial compliance fuel analysis.

Comment 2: Commenter 17316 states that that it is unclear why units that burn a single fuel type are exempt from conducting an initial compliance fuel analysis, which appears to be the intent of section 63.10005(c)(4). The commenter believes the rule seems to be saying that units which intend to demonstrate compliance by fuel analysis are not required to conduct an initial compliance demonstration.

Comment 3: Commenter 17775 requests the EPA clarify the requirements for EGUs combusting single fuels. Although proposed section 63.10005(c)(4) suggests that such EGUs are exempt from any initial fuel analysis, proposed section 63.10011(c)(1) only appears to exempt such EGUs from the requirement to determine the fuel "mixture" that would result in the maximum emission rates. The commenter assumes the EPA intended liquid oil-fired EGUs demonstrating compliance through fuel analysis to conduct an initial demonstration using fuel analysis, but that such EGUs that combust only a single fuel type are not required to make any other demonstrations regarding that sample. The commenter believes the EPA should confirm that understanding in the final rule and provide consistent language in the two provisions.

Comment 4: Commenter 17722 notes that section 63.10005 exempts units firing "a single type of fuel" from the fuel sampling and analysis requirements. According to the commenter, the rule does not define what constitutes a single fuel. The commenter questions if the definition is as broad as coal, natural gas, and fuel oil, or more narrowly defined by ranks (e.g., bituminous, subbituminous, lignite) or even more narrowly ranked by mine location or even coal seam.

Comment 5: Commenter 17775 suggests for EGUs opting to demonstrate compliance using fuel analysis (as opposed to performance testing), the EPA should clarify or remove the reference to operating limits. The commenter believes proposed section 63.10005(c) inexplicably refers to requirements to establish operating limits under section 63.10011 and Table 8. According to the commenter, the only sections of section 63.10011 or Table 8 that could have any applicability to EGUs complying through fuel analysis are the fuel input emission rate calculations in proposed section 63.10011(c) and the fuel pollutant content restrictions in Table 8 (6). The commenter suggests the EPA make clear in the rule that the other operating limits in those provisions do not apply to units complying through fuel analysis.

Comment 6: Commenter 17881 notes that 63.10011(c) is unclear how fuels not covered by the rule (i.e., natural gas) factor in when co-fired with fuels which are subject to the rule.

Comment 7: Commenter 17881 notes that due to the limited number of samples required (3), the P90 calculation in section 63.10011(c) could show a value much greater than the arithmetic average. The commenter believes if this potential HCl content is greater than the limit, the facility should have the option of periodically collecting fuel samples and showing that the actual results meet the limit.

Comment 8: Commenters 18014 and 18498 suggest EPA clarify fuel sampling provisions for multiple fuels. According to the commenters, for units firing a single fuel type, fuel sampling and analysis is not required for supplemental fuels used only for startup, shutdown or for maintaining flame stability per §63.10005(c)(5)). The commenters believe this exemption does not appear to apply to units that fire multiple fuel types or blends and suggest EPA clarify this exemption in the final rule.

3. Fuel sampling procedures.

Comment 9: Several commenters (17316, 17386, 17881) state the fuel sampling procedures specified in section 63.10008(c) and (d) appear to be applicable only to solid fuels and that this section should clarify that these procedures are not applicable to oil (liquid) fuel sampling. Commenter 17881 requests that the EPA clarify if there are any requirements for non-solid fuels; for example, it is not clear for a unit co-firing natural gas if fuel sampling of the natural gas required.

Comment 10: Commenters 17316 and 17386 suggest that fuel sampling for oil-fired EGUs follow 40 CFR 75 Appendix D provisions, which reference ASTM D4057 sampling procedures.

Comment 11: Commenter 17402 suggests the EPA clarify that fuel contaminant levels calculated during performance tests will be used to calculate maximum contaminant levels for fuel content, including allowance for some fuel variability, and not dictate the fuel operating limit directly as an average. According to the commenter, fuel sampling is necessarily a point-in-time sample, while fuel content varies. As a result, asserts the commenter, by setting a standard based on a simple average, the EPA could unnecessarily subject roughly half of all facilities to compliance penalties for using fuel with the identical variability present during the performance tests – i.e., those for which the fuel sample was taken from an above-average portion of the fuel. According to the commenter, instead of effectively encouraging facilities to burn the most contaminated fuel they can during performance testing, the EPA should grant facilities with low emissions a safety margin to reflect variability in fuel and operations. The commenter suggests that the EPA specify that facilities may use fuel contaminants to set a percent reduction for the system, and thus establish a fuel contaminant level (with adequate safety margin) which facilities may use to comply without conducting periodic performance tests as frequently.

Comment 12: Commenters 17730 and 17800 believe the EPA should revise section 63.10008 to make clear that the sampling and compositing procedures in Table 6 may be used. According to the commenters, proposed section 63.10008 requires fuel analysis tests according to the "procedures in paragraphs (b) through (e)" *and* Table 6, and paragraphs (c) and (d) specify minimum sampling procedure and compositing procedures. However, assert the commenters, Table 6 also provides sampling methods that can be used in lieu of those in paragraph (c) and some of those procedures address compositing. For example, state the commenters, ASTM D2013, which the EPA proposes to require for “preparation of composited fuel samples,” also contains procedures for “Preparation of Composite Samples to Represent Lot-Size (or Consignment-Size) Quantities of Coal.” The commenters state the EPA should make clear that any procedure identified in Table 6 can be used in lieu of procedures in paragraphs (c) and (d).

Comment 13: Commenter 17722 notes that section 63.10011 requires fuel samples to be collected and analyzed during initial performance testing that “establishes maximum fuel pollutant input levels.” The commenter believes there is a very low probability that one composite coal sample will contain the maximum concentration of every non-Hg HAP metal that could be expected while combusting coal – even if that coal is from the same mine. Accordingly, the commenter believes it is impossible to demonstrate compliance with section 63.10011. According to the commenter, a typical coal specification sheet will provide the range, average, and standard deviation of the metals in the coal, and it is not unusual for the standard deviation to be 10 to 15% of the average value.

Comment 14: Commenter 17881 notes that section 63.10008 requires the collection of three fuel samples, which seems to be a one-time requirement, whereas the reference to section 63.10008 within section 63.10011(c) would suggest that the provisions be used for on-going periodic sampling.

Comment 15: Commenter 19033 notes proposed regulation section 63.10008 and Table-6 requires fuel sampling for non-Hg metals, regardless of whether or not the EGU operator elects to comply using the PM emission limit. The commenter believes a more representative indicator of fuel content that will impact PM emissions is ash content. In the event the EPA does not accept its recommendation that fuel sampling only be required in the absence of CEMS, the commenter recommends that Table 6 be amended to include an option to sample for ash content, if the EGU operator elects to comply using the PM emission limit.

Comment 16: Commenter 19033 notes that proposed regulation section 63.10011 (b)(3) specifies that a maximum non-Hg metals HAP input be established. According to the commenter, that requirement is valid if the EGU operator elects to comply with the non-Hg metals HAP emission limit and does not operate a PM CEMS. However, in the event the EPA does not accept its recommendation that fuel sampling only be required in the absence of PM CEMS, the commenter believes the regulation should allow establishment of maximum ash content, if the EGU operator elects to comply with the PM emission limits. The commenter recommends that section 63.10011(b)(3) be amended as follows:

> “***lf you elect to comply with the non-Hg HAP metal emission limits, y***ou must establish the maximum non-Hg HAP metals fuel input level (HAP metal input) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section. ***lf you elect to comply with the PM emission limits and do not operate a PM-CEMS, you must establish the maximum ash content fuel input level during the initial performance testing using the procedures in paragraphs (c)(3)(i) and (iii) of this section***.”

In this same connection, the commenter recommends that 63.10021(a)(2) be amended as follows:

> (2) As specified in Sec. 63.10031(c), you must keep records of the type and amount of all fuels burned in each EGU during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of HCl, HF, SO2, non-Hg HAP metals***(if you choose to comply with the non-Hg HAP metals emission limit)***, or Hg, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis and ***do not operate a CEMS for the pollutant or surrogate)***, or result in lower fuel input of chlorine; fluorine,

sulfur, non-Hg HAP metals ***(if you choose to comply with the non-HG HAP metals emission limit), ash (if you choose to comply with the PM emission limit***), or Hg than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance stack testing).

Comment 17: Commenter 19121 believes the EPA is overly prescriptive concerning performance test fuel sampling. Specifically, at section 63.10008(c) and (d), the commenter believes the EPA is not recognizing other methods for collecting and preparing representative fuel samples. The commenter states that ASTM has developed methods that utilize automated and continuous sampling systems, and such equipment is present at many coal plants, and the systems are bias tested against ASTM standards. The commenter also notes there are also ASTM approved sample preparation standards utilizing riffle, grinding, and drying equipment designed to meet applicable ASTM methods.

4. Fuel sampling requirements for sources with CEMS.

Comment 18: Multiple commenters (17402, 17725, 17800, 17820 18014, 18498) believe that the EPA did not intend to require sources using a CEMS to also conduct fuel sampling, but the EPA should clarify this issue in the final rule.

Comment 19: Commenter 17402 requests that the EPA revise section 63.10007 to indicate that fuel sampling is not required when the applicable HAP (or surrogates) are monitored using a CEMS. The commenter requests that the EPA modify the rule to explicitly state that sources using CEMS for compliance for a particular pollutant are exempt from all fuel sampling requirements for that pollutant. According to the commenter, the text of the rule appears to indicate that fuel sampling requirements apply only to those units that demonstrate compliance through “performance testing” for a particular pollutant. The commenter states that as each unit must conduct initial “performance testing,” this could imply that facilities complying by using CEMS must also be required to carry out fuel analysis. The commenter believes that the EPA did not intend to require sources using a CEMS to also conduct fuel sampling, but the EPA should clarify this issue in the final rule.

Comment 20: Several commenters (17725, 17820, 18014, 18498) believe the fuel sampling requirements for units using a CEMS to demonstrate compliance are unclear because of conflicting language in the proposed rule. According to the commenters, the rule does not explicitly state that sources using a CEMS for compliance for a particular pollutant are exempt from all fuel sampling requirements for that pollutant. However, the commenters do not believe that the EPA intended to require sources that demonstrate compliance via CEMS to also have to perform fuel sampling and analysis. The commenters note that fuel sampling is certainly required for oil-fired sources that demonstrate compliance through fuel analysis, and section 63.10011(b) specifies that sources that demonstrate compliance through “performance testing” for a particular pollutant must also perform fuel sampling to “establish maximum fuel pollutant input levels.” According to the commenters, while not formally defined, the rule generally implies that “performance testing” refers to emissions (stack) testing. However, note the commenters, in section 63.10005(a) the EPA states that “performance testing” may also consist of CEMS operating data, thereby creating ambiguity in whether other parts of the rule that pertain to units using stack test data to comply also apply to those units using a CEMS for compliance.

Comment 21: Commenter 17800 believes it is unclear from the way the regulation is written if EGUs complying with CEMS systems must meet fuel input limits established during the performance testing. The commenter cites section 63.10011(b), noting that since all EGUs are required to demonstrate initial compliance with each emission limit "through performance testing," and the proposed rule defines "performance testing" to include the first 30 operating days of CEMS data, the proposal appears to require that EGUs meet fuel input limits regardless of the "performance testing" option they choose. According to the commenter, the proposal appears to require that EGUs meet operating limits for all relevant control devices and load regardless of the "performance testing" option they choose.

Comment 22: Commenter 17758 notes that proposed section 63.10008 lays out in detail a fuel sampling and analysis regimen; however, none of the fuel information is meaningful or relevant when either all of the regulated HAP or their surrogates are continuously monitored. The commenter notes that proposed section 63.10008(a) contains an "as applicable" clause, but its meaning is never explained.

Comment 23: Commenter 17881 suggests that section 63.10011(b)(2) not apply to units with Hg CEMS (i.e., categorically all solid fuel-fired units, as these units are required to install Hg CEMS). The commenter also believes the Hg content of coal may not correlate to the Hg emissions at the stack, therefore trying to establish a maximum Hg fuel input level in the fuel prior to testing is not a good indication of what will actually be emitted when utilizing the equations. According to the commenter, for example, the form of the Hg emissions from coal combustion (i.e., elemental, oxidized and particle bound) can have a major impact upon Hg emissions, as these forms are controlled to varying degrees by prevalent control technologies. The commenter states that certain coals tend to favor elemental forms of Hg emissions as opposed to oxidized forms of emissions. Thus, according to the commenter, you could have a case where a coal with a high Hg content also results in a high percentage of Hg emissions in the oxidized and particle bound forms. According to the commenter, such a coal may yield lower Hg stack emissions than a coal with a lesser Hg content but that yields a much higher percentage of elemental Hg emissions (as this form of Hg is not as readily removed in prevalent control technologies).

Comment 24: Commenter 18015 requests that the EPA clarify the applicability of the fuel analysis requirements; specifically, the commenter recommends that the EPA state in the preamble and the final rule that fuel analysis is not required for units that use CEMS to continuously comply with emission standards. According to the commenter, should the EPA agree with the commenter's request to allow a percent removal MACT standard approach (discussed separately), then the Hg content of the coal will have to be determined in a routine manner.

Comment 25: Commenter 17881 believes it is not clear if the requirement contained in section 63.10021(a)(8) applies to solid fuel-fired EGUs which are demonstrating compliance with the PM surrogate. The commenter believes that is should not apply, as a CEMS is installed to verify continuous compliance, and that this paragraph makes little sense for units without PM CEMS that are required to test monthly or bi-monthly; thus, the tests would already be conducted within the frequency (60 days) specified in the paragraph.

5. Fuel sampling requirements for single-fuel units that comply with one or more standards based on stack testing.

Comment 26: Commenters 17402 and 18498 believe that the EPA should allow facilities to conduct more frequent fuel sampling to show continuing compliance based on their performance tests instead of using CEMS.

Comment 27: Several commenters (17402, 17820, 18498) believe the rule is unclear as to whether units that fire a single type of fuel are exempt from all fuel sampling and analysis requirements. According to the commenters, the EPA appears to exempt units that fire a single fuel type from conducting fuel analysis as part of the initial compliance requirements in section 63.10005(c)(4). However, state the commenters, in section 63.10011, the procedures used to establish the fuel operating limits include a directive for handling single-fuel units. Despite these inconsistencies, the commenters believe that it was probably the EPA's intention not to require single-fuel sources to conduct ongoing fuel sampling, and thus the commenters propose fuel testing only be required every six months, unless a facility changes fuel type. According to the commenters, this approach is consistent with the approach taken in the final Industrial Boiler MACT rule, which did not require any ongoing fuel testing. The commenters note that the EPA explicitly states in the definition of "fuel type" in section 63.10042 that changes in vendors for a particular fuel type are not considered a change in fuel type, and assert that this indicates a belief that fuel sampling is not required within fuel types. According to the commenters, the EPA should clarify the fuel sampling requirements for single-fuel units that comply with one or more standards based on stack testing.

Comment 28: Commenters 17725 and 17820 note that for units firing a single fuel type, fuel sampling and analysis is not required for supplemental fuels used only for startup, shutdown or for maintaining flame stability (section 63.1 0005(c)(5)) According to the commenters, this exemption does not appear to apply to units that fire multiple fuel types or blends, and they request that the EPA clarify this exemption in the final rule.

Comment 29: Commenter 17722 requests that EPA clarify that fuel testing is not required for sources that combust a single fuel, excluding limited secondary fuel use for startup, shutdown or flame stabilization. The commenter believes single-fuel plants should be exempt from the requirements under section 63.10007(c) which states "you must conduct the performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content of chlorine, fluorine, non-Hg HAP metals, and Hg, and you must demonstrate initial compliance and establish your operating limits based on these tests."

Comment 30: Commenter 17775 recommends the EPA clarify or remove the operating limit requirements, and clarify the fuel analysis requirements for single fuel EGUs and supplemental fuels.

6. Low emitting EGUs.

Comment 31: Several commenters (17402, 17754, 17808) believe the LEE monitoring requirements are overly burdensome. Commenter 17808 believes in many cases, monthly fuel testing would be redundant as this requirement would result in the repetitive testing of the same fuel shipment (see further discussion below in the context of oil-fired units). Commenter 17402 believes the monthly sampling requirements are arbitrary as there is no requirement in the rule to establish a fuel operating limit. Further, although fuel changes are addressed in the preamble, they are not directly addressed with regard to LEEs in the rule itself. For LEE single fuel facilities, Commenter 17402 believes that fuel sampling should only be required every six months, or on a change of fuel. Further, Commenter 17402 believes that if any increases in concentration are small enough that based on the facility's demonstrated contaminant reduction performance on the prior stack test they would not cause the LEE limit to be met, then retesting of performance should not be required.

Comment 32: Commenter 17775 states that if EPA intended to require that LEEs perform monthly fuel analysis under section 63.10006(c), the EPA needs to make clear that compliance with the maximum fuel input levels is not required and explain why it chose *monthly* testing. According to the commenter, analyzing fuel monthly when the fuel supply or mixture has not changed seems unnecessary. The commenter states that if the EPA intended to require that LEEs establish and comply with maximum fuel input levels as an "operating limit" under section 63.10011(b), rather than perform monthly fuel analysis, the EPA needs to explain that the fuel analysis is an operating limit and not a demonstration of compliance using fuel analysis under section 63.10011(c). According to the commenter, the EPA also needs to remove the *monthly* fuel sampling and analysis requirement in section 63.10006(c). If the EPA intended to require that LEEs establish and comply with operating limits other than maximum fuel input levels, the commenter states, the EPA needs to issue a proposal that explains the purpose of those limits and how they apply.

Comment 33: Several commenters (17725, 17820, 18498) believe the fuel sampling requirements for LEE units are ambiguous and provide no compliance value since the rule does not require the establishment of a fuel input operating limit. According to the commenters,, the requirements do not address single-fuel units, changes in fuel type, or units that burn or co-fire multiple fuels. The commenters assert that presumably, LEE units would follow an analogous procedure as non-LEE units and reassess the ability to meet LEE status based on the new fuel type/blend; this would require sources that burn multiple fuel types or blends to establish a fuel-input operating limit during the initial compliance demonstration. Consistent with the non-LEE requirements, the commenter suggests the EPA remove the arbitrary monthly sampling requirement and allow sources to conduct fuel sampling only when there is a change in the fuel type. For single-fuel units, the commenters suggest the EPA specify that these units are not required to comply with any of the fuel sampling requirements.

Comment 34: Commenter 17754 suggests that to the extent that the EPA does not revise the proposed rule to allow LEE units to demonstrate continuous compliance through annual performance testing only, rather than monthly fuel evaluations, and instead insists upon requiring that all LEEs demonstrate continuous compliance using a fuel factor based approach, the EPA should nonetheless revise the specific fuel factor based approach currently required under the proposed rule. The commenter believes the requirement to use the 90th percentile confidence level to determine the operating limit for Hg is improper, because the use of such value could cause a LEE to lose its LEE status, even though the unit's actual Hg emissions remain substantially below the LEE thresholds.

Comment 35: Several commenters (19536, 19537, 19538) believe the EPA should discard its "Low Emitting Units" monitoring protocols. The unavoidable variability claimed by the EPA, moreover, indicates that plant emissions range as much as 50 times higher than the results of a three-run test. As a result a plant with test data at 50% of the proposed standard will likely – indeed, almost certainly – exceed the prescribed limit during its operations. Yet the only compliance monitoring required for an LEE is an initial performance test, and subsequent check-up performance tests every 5 years, coupled with monthly fuel sampling. That monitoring provides no assurance of continuous low-HAP emissions. Fuel sampling would reveal no information about HCN, which is a byproduct of combustion and cannot be inferred from fuel sampling. Further, fuel sampling would disclose no information about HAP that did not originate in the fuel. Additives, such as PVC, are sometimes blended with the fuel to facilitate Hg control. Metals are present in the reagents (limestone, lime) and water used in scrubbers. Metals are also released from the boiler, duct work, and control systems. These would not be detected by fuel sampling.

Comment 36: Commenter 17808 recommends that for non-Hg HAP as well, owners/operators of a LEE unit have the option to conduct an annual performance test to demonstrate that emissions are less than 50 percent of the relevant emissions standard. The commenter notes that the EPA proposes that for all other HAP, LEEs would demonstrate continuous compliance and maintain LEE status through monthly fuel analysis as well as performance (stack) testing every 5 years. However, in many cases, according to the commenter, monthly fuel testing would be redundant as this requirement would result in the repetitive testing of the same fuel shipment.

Comment 37: Commenter 17807 suggests the EPA reconsider the use of fuel samples as the method of compliance for the maintenance of LEE status and alternatively suggests using the fuel samples as a control similar to the intent of the EPA; however, the compliance should be based on a 12-month rolling average of the key parameters in the fuel. According to the commenter, if the 12-month rolling average of fuel samples shows a monitored parameter over the threshold then a stack test would be triggered. This procedure would ensure that only an actual emissions exceedance could cause a unit's LEE status to be lost.

7. Liquid oil-based EGUs.

Comment 38: Several commenters (17758, 17775, 18428) suggest the alternative fuel analysis provisions should apply to all affected liquid oil-based EGUs. One commenter cites the summary of the rule proposal 76 FR 25031, in which the EPA states that this provision applies only to limited-use oil units and not other affected oil units. The commenter explains that the provisions of the proposed rule itself (sections 63.10005(c) and 63.10006(s)) appear to indicate that owners/operators of all affected liquid oil-fired units may perform fuel analyses to demonstrate initial and continuous compliance with applicable emission limitations, as an alternative to performance stack testing. The commenter requests that the final rule clarify that the alternative to use fuel testing to demonstrate initial and continuous compliance applies to all affected liquid oil-fired EGUs, not only limited-use units. Commenter 17775 also requests that the EPA further explain its preamble statements in order to allow meaningful comment on that procedure.

Comment 39: Commenters 17386 and 17621 believe the fuel oil metals analysis methods are not sensitive enough to support compliance monitoring for limited use oil EGUs. Commenter 17386 states that based on contacts with a number U.S. laboratories, standard available analytic techniques are not capable of achieving the detection limits required to demonstrate compliance with proposed MACT emission limits for certain HAP Metals (such as cadmium, beryllium and antimony) in liquid fuel oils. The commenter states the fuel oil concentration for cadmium, beryllium and antimony would have to be < 5 ppb to demonstrate compliance with MACT limits, and none of the laboratories contacted could achieve this detection level.

Comment 40: Commenter 17386 notes the detection limits of the analytical methods for non-Hg metals in oil are too high to support compliance verification. According to the commenter, in the ICR Part III database, most of the fuel oil metal concentrations are non-detect values, with detection limits ranging from 0.25 to 10 parts per million by weight (ppmw). The commenter states that this range is equivalent to approximately 10-6 to 10-4 lb/MMBtu, while the proposed MACT metal emission limits for existing oil-fired units range from 10-7 to 10-6 lb/MMBtu. The commenter states that fuel samples from several oil-fired EGUs were analyzed with ASTM D6357, the method specified in the ICR for coal, not oil, and that this method gave lower detection limits, on the order of 0.01 ppmw, or approximately 10-7 lb/MMBtu. According to the commenter, the use of ASTM D6357 for oil samples may give inaccurate results for metals because the ashing step that works well for coal can cause the loss of metals in oil samples, resulting in erroneously low metal concentrations. The commenter asserts that fuel oil metals concentrations would need to be quantifiable below 0.01 ppmw to demonstrate compliance. According to the commenter, the analytical techniques currently used for fuel oil samples by most laboratories cannot measure accurately at those levels. The commenter suggests allowing fuel oil monitoring to be used as a compliance method for limited-use EGUs, a new or improved standard certified method for fuel oil will be required.

Comment 41: Commenter 17718 suggests the EPA should clarify whether the fuel analyses and procedures in the proposed regulatory language (40 CFR section 63.10008) are only applicable to liquid oil-fired EGUs that desire to meet their applicable emission limits through fuel sampling.

Comment 42: Commenter 17760 suggests the EPA should clarify that all liquid oil-fired units may demonstrate compliance through fuel analysis. The commenter believes the language in the preamble to the proposed rule and the proposed regulatory language are inconsistent regarding the availability of the fuel analysis option. The commenter believes the preamble seems to limit the option to limited-use liquid oil-fired units, citing 76 FR 25031, while the regulatory language seems to allow all affected liquid oil-fired units to utilize the fuel analysis option, citing 40 CFR 63.10000.

Comment 43: Commenter 17796 suggests the requirements for liquid oil-fired units are confusing and should be rewritten for clarity. The commenter cites "What Are My General Requirements/or Complying with this Subpart", paragraph (c)(2), which states that liquid oil-fired EGUs can demonstrate initial and continuous compliance using fuel analysis, noting that these general requirements are contradicted in section 63.10006, which specifies different continuous compliance methods for liquid oil-fired units.

Comment 44: Commenter 17718 suggests that within the proposed regulatory language (40 CFR section 63.10011(b)), where reference is made to conducting fuel analyses and establishing maximum fuel pollutant input levels "…as applicable", the EPA should clarify that the fuel sampling, analyses, and maximum input levels are only applicable to liquid oil-fired EGUs that choose to meet their emission limits through fuel sampling methodologies. The commenter believes the establishment of fuel limits appears applicable only to facilities that choose to comply via fuel analysis. The commenter believes if facilities apply CEMS, accurate compliance can be determined at the emission point and, therefore, the fuel input becomes irrelevant. The commenter also states that there are numerous inaccurate section/paragraph references within the proposed regulatory language of 40 CFR section 63.10011(b). The commenter suggests the EPA carefully review this section to properly link references to the appropriate sections and paragraphs.

8. Monthly fuel analysis.

Comment 45: Several commenters (17386, 17758, 17760, 17902) believe the monthly fuel analysis contained in section 63.10006(s) would be unnecessarily burdensome, costly and impractical. One commenter suggests requiring fuel analysis to be performed on each shipment of oil received should be adequate to demonstrate compliance. Commenter 17760 notes that oil-fired plants require verification that fuel oil meets certain specification prior to accepting a delivery and after a plant accepts a shipment of fuel oil and places it in a storage tank and that it is highly unlikely that the composition of the fuel oil will change. Commenter 17386 notes that for large fuel oil storage tanks which receive oil deliveries less frequently than monthly the requirement is unjustified and proposes fuel sampling for oil-fired units shall be performed quarterly only during periods when fuel oil replenishment has been made to the fuel oil storage tank. Commenter 17902 recommends that this requirement be revised to require sampling only when there is a fuel switch, new fuel, fuel shipment, or change in fuel source. In addition, this commenter suggests the final rule should allow use of fuel supplier data for each shipment as an alternative approach.

Comment 46: Commenter 17731 suggests the EPA remove the requirement that EGUs without control devices conduct HCl emission testing every month, 76 FR 25029/3, for units that otherwise meet the HAP emission limits. The commenter believes this burdensome requirement offers no environmental benefit because compliant emission levels can be explained by fuel sources. The commenter suggests a better alternative would be yearly stack testing with a monthly fuel sampling.

Comment 47: Commenter 17807 notes that although they prefer that SO_2 be used as a surrogate, they do not object to allowing utilities to opt to perform routine HCl testing or continuous emission monitoring. The commenter requests that the EPA allow utilities to choose to demonstrate compliance for HCl through routine fuel sampling. According to the commenter, most facilities currently utilize some type of fuel sampling methodology to test their fuels burned, and the chloride content can be analyzed using ASTM 4208/300 along with existing fuel test methods. The commenter notes that facilities will need to establish an upper chloride threshold in the fuel as demonstrated by HCl stack testing and that once the limit is established, the daily or weekly chloride analyses on a 30-day rolling average will demonstrate compliance provided the threshold is not exceeded. The commenter believes this will provide an established procedure to ensure compliance.

9. Site-specific fuel analysis plans.

Comment 48: Commenters 17775 and 17800 state that although the commenters do not object to a requirement to submit a plan or to use standardized procedures, as required by section 63.10008; however, because there is so much diversity in how fuel is received, stored, and processed at individual facilities, the commenters assert that the EPA needs to allow more flexible procedures to accomplish the primary objective.

Comment 49: Commenters 17775 and 17800 discuss that under proposed section 63.10008(b)(1), the proposed plan must be submitted to the Administrator at least 60 days before the fuel analysis. Because some of the information required to be included may change from analysis to analysis, the commenter assumes the EPA intends sources to submit a new plan or update the existing approved plan if information changes. For example, the commenter notes, the plan must include identification of all fuel types anticipated to be combusted and whether the source or fuel supplier will conduct the analysis. Proposed section 63.10008(b)(2). According to the commenter, although it might be possible to submit that information 60 days in advance of the initial demonstration and receive approval before conducting the analysis, it may not be possible for subsequent analysis in response to changes in fuel type or fuel mixtures (since those might occur with less notice or planning). According to the commenter, the requirement to submit a new or revised plan also makes little sense if monthly analysis is required. The commenter requests that the EPA either remove the requirement for advance submittal and approval of a plan after the initial compliance demonstration, or remove the requirement to include in the plan information that might change.

Comment 50: Commenter 17821 does not object to the requirement to develop a site-specific fuel analysis plan and does not object to submitting it to the EPA; however, the commenter sees little value in the requirement that the EPA must approve the plan before it can be implemented. The commenter believes that the requirements for development of the plan are specified in the proposed rules and sources are fully capable of following and implementing those requirements. The commenter notes there will be hundreds of fuel analysis plans submitted to permitting agencies and the EPA in a very short period of time which can result in a backlog of plans to be reviewed, which could easily mean that a source submitting a plan before the 60-day deadline in advance of testing may not receive approval to use the plan before it must conduct that testing. The commenter notes that if the delay is extensive, this could mean that a source might not be able to complete performance testing before the deadlines specified in the rules. The commenter therefore urges the EPA to modify this section of the proposed rule to eliminate the requirement for the EPA to approve fuel analysis plans prior to conducting testing.

Comment 51: Commenter 17881 notes that section 63.1008, requiring development of a site specific fuel analysis plan, as applicable, is very unclear how to determine if you need a fuel analysis plan as section 63.10005 does not stipulate which units are required to conduct fuel analysis on an on-going basis. Provision (b)(2)(iv) requires that the minimum expected detection level for chlorine, fluorine, Hg, and metals be included in the plan. The commenter notes that the EPA should clarify that fluorine is only applicable for oils. The commenter advocates that the EPA provide guidance on required minimum detection levels for these parameters.

10. Performance testing and fuel analysis.

Comment 52: Commenter 17775 cites proposed section 63.10011(b) that "if you demonstrate compliance through performance testing, . . . [y]ou must also conduct fuel analysis according to § 63.10008 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (5)." (The commenter notes that Table 8 actually refers to section 63.10011(c) and (d), but the EPA probably intended to reference (b) and (c).) According to the commenter, table 8 also requires EGUs to continue combusting only the fuel types and mixtures used to demonstrate compliance with fuel input levels under section 63.10011(b) and (c). The commenter states that accordingly, any unit that demonstrates compliance using "performance testing" would, under Table 8, be limited to combusting only those fuels or mixtures used during initial performance testing.

Comment 53: Commenter 19033 suggests the EPA clarify the meaning of "highest content" contained in 63.10007(c). The commenter cites an EGU operated which is a coal-fired unit with natural gas firing capability during periods of start-up; however, the coal burned in this EGU comes from more than one mine source. The commenter notes that it will make a good faith effort to identify the coal that has the maximum anticipated amount of chlorine, and Hg, and base its tests on that coal; however, it will be unable to certify that coal from another section of the mine will not have higher chlorine or Hg content than what was tested, due to the variable nature of coal. The commenter also notes it may also be possible that a coal with a maximum chlorine content may not be the coal that also has the maximum mercury content.

Comment 54: Commenter 18447 questions the EPA statement in the preamble of the proposed rule that "For units without wet or dry FGD scrubbers that must comply with an HCl emission limit, you must measure the average chlorine content level in the input fuel(s) during the HCl performance test. This is your maximum chlorine input operating limit." The commenter believes that this means that once the HCl performance test has been completed and the chlorine results are known, the fuel that was used during the test cannot be used again. According to the commenter, this is because the fuel's measured average chlorine value now becomes the maximum chlorine limit; the fuel that created the maximum chlorine limit (by virtue of its average) will now exceed the maximum limit 50% of the time (by virtue of the normal distribution curve) and therefore cannot be used again. The commenter believes as written, it creates a possible incentive to test with a fuel with a high chlorine content, and then switch back to a fuel with a lower chlorine content, whose maximum chlorine content is less than test fuel's average chlorine content.

Comment 55: Commenter 19033 suggests that the EPA clarify section 63.10007(c) with respect to the requirement that coal which has the highest non-Hg metals must be tested, especially if the EGU operator elects to comply using the PM emissions limit, which is a surrogate for non-Hg metals. The commenter suggests that the phrase in question be amended, as follows:

> "You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content-of chlorine, . fluorine, non-Hg HAP metals (**if you elect to comply with the non-HG metals HAP emission limitation**), and Hg, and you must demonstrate initial compliance and establish your operating limits based on these tests."

11. Continuous compliance.

Comment 56: Commenter 17881 suggests the provisions of section 63.10021(a)(2) should state that fuels used for start-up/shutdown and flame stabilization are exempted from this requirement. Also, according to the commenter, it is the fraction of heat input which is relevant to meeting the emission limit, not the overall fuel mass (based on the HAP input calculations at section 63.10011). According to the commenter, the requirement to keep records of the amount of fuel burned in each EGU is not relevant to any compliance requirement in the rule, and the utility industry already reports fuel usage to the Department of Energy, Energy Information Administration in various reports. The commenter notes that this information is available for the EPA to access.

Comment 57: Commenter 17881 suggests that with respect to section 63.10021(a)(5), if the EPA allows actual sampling vs. theoretical results, then these provisions would not apply as direct sampling would be used to demonstrate compliance. The commenter believes the monthly compliance demonstration through fuel analysis is all that is required to comply with the Hg emission limit instead of trying to theoretically pre-qualify a fuel.

Comment 58: Commenter 17781 suggests that with respect to 63.10021(a)(3), if the EPA allows actual sampling versus theoretical calculated results, then the provisions of this paragraph would not apply as direct sampling would be used to demonstrate compliance. The commenter believes the EPA should leave it up to the facility to demonstrate compliance, as it does not make sense to try and pre-qualify emissions. According to the commenter, the logistics of trying to pre-qualify a fuel does not work in the real world, as what is sampled for the pre-qualification analysis is most likely not what is really burned, as oil is blended in a storage tank prior to burning; the onus of proof of compliance is on the facility.

12. Chloride concentration variability.

Comment 59: Commenters 17816 and 19114 note HCl CEMS currently are not commercially available or adequate for in-stack measurements at coal-based EGU's, and are not anticipated to be available by the compliance date of the rule. As a result, according to the commenters, sources will be forced to either take a fuel limit or an operating parameter limit. The commenters believe the fuel analysis limit is impractical because of the inherent variability of chloride concentrations in coal, both between various ranks of coal and within the same coal category. According to the commenters, it will be impossible to control fuel deliveries in such a manner as to negate the possibility of burning coal with chlorine content above that which was used during compliance testing.

13. Stop belt sampling (section 63.10008(c)(1)(i)).

Comment 60: Commenters 17715 and 19114 suggest the EPA remove the provisions for affected sources to conduct stop belt sampling or to pull samples from the coal piles during testing. The commenters believe stop belt sampling is neither safe to conduct due to stored energy in the conveyor belts, nor is it representative of a unit's operation. According to the commenters, a unit may have to reduce process rate due to a decrease or a lag in the time that the fuel is being delivered. The commenters assert that sampling from the coal pile will not gather coal samples that are representative of what is being burned. The commenters note they have coal piles that are greater than 15 acres in area and gathering five samples uniformly spaced at a depth of 18 inches will not adequately represent what is being burned during the test period.

Comment 61: Commenter 17722 notes that stopping and starting a coal belt that is moving tons of coal is problematic and labor intensive. According to the commenter, the sampling procedures are applied to screw conveyors, and the commenter believes it is impossible to withdraw a six-inch wide cross section from a screw conveyor because of the auger system.

Comment 62: Commenters 17722 and 19114 suggest the EPA should allow the EGU operator to determine the best available method to collect a representative sample. Commenter 19114 suggests that the EPA specify a number of representative fuel samples during the testing.

Comment 63: Commenter 17800 believes the proposed stop belt sampling requirements for collecting composite fuel samples is not reasonable and apparently would not allow for the use of continuous belt samplers. According to the commenter, in addition, many belts cannot be restarted with coal on them because the belt is too heavy for the motor to start. The commenter asserts that for sampling piles or trucks, the rule requires (among other things) use of a "square shovel," collection of samples at a depth of exactly "18 inches," collection at five locations "uniformly spaced over the surface of the pile," and breaking of pieces larger that exactly 3 inches (citing proposed section 63.10008(c)(2)(ii) and (d)). The commenter believes representative samples can be taken with shovels of other shapes, at depths greater or less than 18 inches, and without measuring the actual size of individual coal pieces. The commenter requests that the EPA remove the prohibition on moving belt samplers and reexamine and moderate the pile sampling requirements to provide more realistic criteria (e.g., use the same shovel for all samples, collect samples at a uniform depth of approximately 18 inches, and break apart large pieces (e.g., pieces greater than 3 inches).

Comment 64: Commenter 17881 expresses concern over sampling from a belt, as there are significant safety risks with reaching across a belt. The commenter asserts that according to safety requirements, the belt would have to be locked out and tagged out in order to cross the vertical plane of a belt. According to the commenter, plant personnel currently collect coal samples from a feeder chute just prior to the coal mill, and the commenter suggests the EPA should consider other sampling alternatives to those currently presented in section 63.10008(c).

Comment 65: Commenter 18015 believes the EPA requirement of stopping the coal belt to take coal samples in a swath across the belt is unnecessary and can create operating problems. According to the commenter, every time a coal belt is stopped, a risk is incurred, however slight, of having difficulty restarting the belt, and it is possible to get good representative samples without stopping the coal belt. According to the commenter, EGUs have been following such practices successfully for many years. The commenter believes the EPA should eliminate the requirement to stop the coal belt to take samples.

Comment 66: Commenter 19121 believes requiring belt stop and starts during plant operation is dangerous, logistically and operationally intrusive, and unnecessary.

14. Coal sampling methods.

Comment 67: Commenter 17821 objects to the requirement of a manual coal fuel-sampling method as proposed in section 63.10008(c), (c)(1)-(2). The commenter notes they utilize automated mechanical coal sampling systems that are operated under procedures such as those described in ASTM D2013. According to the commenter, these automated methods are widely accepted and do not require the labor-intensive and time-consuming procedures described in the above referenced sections of the proposal. The commenter believes the EPA should allow the use of automated sampling procedures that follow standard practices referenced in appropriate ASTM or other such methods that are written by experts in their fields and are peer reviewed. In other rulemakings, the EPA has referenced ASTM standard practices. The commenter suggests these rules should allow the use of those standards and should not require a manual method of sampling.

Comment 68: Commenter 17821 strongly urges the EPA to avoid writing detailed sample preparation procedures as specified in section 63.10008 (d), (d)(1)-(7). In lieu of the agency writing their own procedures, the commenter believes the proposal should reference appropriate ASTM standards that are widely used by the utility industry, and others and such sample preparation methods that are written by experts in their fields and are peer reviewed. The commenter notes that in other rulemakings, the EPA has referenced ASTM standard practices. According to the commenter, these rules should allow the use of those standards and the EPA should not take on the challenge of writing special procedures that are unique to this rulemaking.

15. Other comments.

Comment 69: Commenter 17725 notes that the EPA defines the two coal-fired unit subcategories as based on 1) the calorific value of the coal the boiler is designed to combust and 2) the boiler dimensions in terms of height-to-depth ratio. According to the commenter, the larger boiler dimensions are a result of the inherently higher mineral matter of these fuels. The commenter states that there are two issues that warrant clarification so that compliance requirements are easily determined and understood: First, many, if not most lignite units burn a blend of coals, e.g., lignite and PRB; and second, the industry standard for determining heating value of as-received coal is based on an ultimate/proximate analysis. According to the commenter, clarification is needed from the EPA regarding their reliance on the moist mineral matter free heating value (ASTM D388) of coal. The commenter states that this method is typically relied upon to classify distinct coal regions and individual seams don’t vary significantly within a region. According to the commenter, the ASTM D388 method specifically excludes any samples of weathered or oxidized coal be used for coal rank classification and further requires no less than three samples to be taken within the same mine or locality of the coal bed in accordance with U.S. Bureau of Mines sampling methods.

Comment 70: Commenter 17725 suggests the EPA remove redundant stack test requirements. The commenter notes that the EPA has established alternative limits for compliance for various HAP groups and these options provide the sources with a measure of flexibility. However, the commenter believes the EPA is requiring stack tests for both the pollutant and surrogate. According to the commenter, since limits for each pollutant (or surrogate) have been independently established to assure effective reductions in accordance with section 112 of the CAA, the commenter believes there is no need to test for both the pollutant and surrogate. The commenter believes a performance test should only be required for the pollutants and surrogates with which the source is choosing to show compliance (e.g., if a source is demonstrating compliance for acid gas HAP using SO_2, it should not be required to conduct a HCl performance test) and suggests the extra tests are superfluous since the surrogacy has already been established.

Comment 71: Commenter 17881 discusses issues with Table 6 – Fuel Analysis Requirements, noting that this requirement stipulates the use of Method 19 fuel factor (F-factor) methodology to convert emission concentrations into units of lb/MMBtu. According to the commenter, Method 19 does not contain procedures for converting any constituent other than sulfur percent by weight into an equivalent pollutant emission rate on an energy input basis. Furthermore, states the commenter, it is wholly unclear how one would convent a fuel constituent concentration into units of lb/MWh, as such a conversion would not be based on just the fuel characteristics (i.e., constituent concentration and heating value) but would instead also relate to the heat rate of the unit in which the fuel is to be combusted. The commenter suggests the EPA should either remove the reference to converting the concentration to units of lb/MWh, or should provide clear procedures for conducting the associated calculation(s).

Comment 72: Commenter 18025 recommends the EPA set a percent water content limit for oil, rather than setting HCl and HF emissions limits for liquid oil-fired EGUs. The commenter notes ASTM test methods are available for measuring the percent water content of fuel oil (D95 and D473). The commenter suggests that plant operators would test each shipment received to ensure compliance with the proposed limit.

Comment 73: Commenter 18483 suggests that should such IGCC or other generating units remain subject to the rule, fuel sampling should be allowed as a sole compliance demonstration option in lieu of a Hg CEMS or sorbent trap methodology due to Hg being removed from the fuel prior to combustion and the lack of post-combustion controls.

Comment 74: Commenter 19114 notes that IGCC processes are inherently different from other methods of coal-based electric generation and more similar to natural gas combined cycle units in terms of design and emissions. According to the commenter, if IGCC units are not exempted in the final rule, then the standards should be revised to address the unique characteristics of IGCC processes. The commenter believes that issues that would need to be addressed include: the applicability of fuel sampling requirements, gasifier feedstock sampling, raw syngas sampling, clean syngas sampling, syngas fired in the combustion turbines, syngas fired in a flare, processed syngas fired in thermal oxidizer, etc.

Comment 75: Commenter 17775 notes concerns with applicability with provisions and paragraphs cited in section 63.10011(b). With respect to operating limits, the commenter believes proposed section 63.10007 does not discuss applicability at all. According to the commenter, with the exception of the filterable PM limit applicable to units using PM CEMS, Table 7 also does not distinguish between compliance options. Instead, states the commenter, Table 7 refers to various parameters depending on which control device "your operating limits are based on" (citing section 63.10011(b)(6)). (The commenter notes that although the rule actually cites section 63.10011(c)(6), that provision addresses fuel sampling, not operating limits. As a result, the EPA probably intended to reference (b)(6).) According to the commenter, Table 7 also refers only to specific control devices and not compliance options. With respect to fuel input levels, the commenter asserts that paragraphs (c)(1) through (5) specify how fuel input levels are established but do not identify which EGUs must establish them. The commenter notes that proposed section 63.10008 requires "performance fuel analysis tests" "as applicable"; Table 6 requires fuel analysis "as stated in section 63.10008"; and proposed section 63.10031 requires compliance reports to address compliance with fuel input limits "for sources that demonstrate compliance through performance testing."

Comment 76: Commenter 17801 notes on page 25037 of the proposal the EPA provides an option to monitor inlet chlorine, fluorine, non-Hg metals and Hg in liquid oil to meet outlet emission rate limits, noting that it is reasonable to do so because oil-fired units remove these fuel-borne HAP from the oil before combustion in lieu of installing air pollution control devices (APCD). In response to the EPA's request for comment on the viability of this approach for IGCC, the commenter agrees that fuel monitoring (of the syngas) should be an option for IGCC as well based on the same reasoning as to that fuel "clean-up" vs. APCD. The commenter believes fuel sampling should be allowed as a sole compliance demonstration option for IGCC in lieu of a Hg CEMS due to Hg being removed from the fuel prior to combustion and the absence of post-combustion controls in lieu of pre-combustion control.

Response to Comments 1-76: Based on the comments received and a further review of the technical challenges associated with the proposed fuel analysis requirements, the EPA has not finalized the proposed fuel analysis requirements. Fuel analysis of moisture for certain liquid oil-fired units remains a compliance assurance option. As the rule no longer requires operating limits for pollutants based on fuel content or fuel analysis, the comments summarized above are largely moot. For low emitting EGUs, the agency agrees that the proposed LEE ongoing eligibility requirements were overly burdensome and restrictive. As a result, existing solid- or liquid-fired units that qualify for LEE status for Hg will be required to conduct a 30-day test for Hg using Method 30B each year. Neither fuel analysis nor adherence to an operating limit will be required. Should an annual test show ineligibility for LEE status, the unit would revert to the requirements for Hg monitoring using CEMS or sorbent traps or quarterly emissions testing. For other pollutants, a unit can qualify for LEE for an applicable pollutant if all performance tests over a 3-year period demonstrate that the unit remains below 50% of the emission limit for the applicable pollutant. Under those circumstances, the unit would qualify for emissions testing of that pollutant every 3 years to demonstrate ongoing compliance with the rule.

The only fuel analysis provision in the final rule is an optional compliance assurance method for liquid oil-fired units. If you combust liquid fuels, if you wish to demonstrate ongoing compliance with HCl and HF emissions limits by measuring fuel moisture content, and if your fuel moisture content is no greater than 1.0 percent, you must measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or measure fuel moisture content daily if your fuel arrives on a continuous basis; or obtain and maintain a fuel moisture certification from your fuel supplier. Should the moisture in your liquid fuel be more than 1.0 percent, you must either: (1) conduct HCl and HF emissions testing quarterly and develop a site-specific monitoring plan to monitor appropriate operating parameters to ensure that operations remain consistent with those present during performance testing; or (2) use an HCl CEMS and/or HF CEMS.

5A04 - Testing/Monitoring: Detection levels

Commenters: 17316, 17386, 17621, 17622, 17711, 17715, 17725, 17730, 17775, 17790, 17800, 17821, 17873, 17902, 17914, 18034, 18429, 18443, 18498, 18023

1. Analytical techniques and detection levels.

Comment 1: Commenters 17316 and 17386 state that based on contacts with a number of laboratories, it appears that standard available analytic techniques are not capable of achieving the detection limits required to demonstrate compliance with proposed MACT emission limits for certain metals, such as cadmium, beryllium and antimony, at least in oil. Commenter 17316 refers to a Table (note: this table is not attached to the comment), that allegedly addresses the concentration in oil for each regulated HAP metal corresponding to proposed MACT emission limits for oil fired EGUs. According to the commenter, for cadmium, beryllium and antimony, the concentration in oil would have to be < 5 ppb to demonstrate compliance with MACT limits, and according to the commenter, none of the laboratories contacted could achieve this detection level. Moreover, the commenter questions the accuracy of analysis results determined by the specialized methods used to reach the detection levels required for such a compliance demonstration on fuel oil.

Response to Comment 1: The requirements for fuel sampling and analysis for the listed metals have been removed from the final rule.

Comment 2: Commenter 17622 states that based on information provided in the proposed rule, they cannot validate that technology exist to accurately measure the proposed emission limits for new units. The commenter states monitoring systems have to be capable of accurately measuring emissions below the limits established by the EPA and in practice emission control technologies must be able to provide long term control at emission levels below the proposed limits. The commenter notes that when the EPA sets an emission limit, all EGUs establish operating levels below the EPA or permit levels, to some extent, to compensate for operational variability, fuel changes, and startup and shut down times that occur during normal plant operations, and in order to remain in compliance over the averaging period. Therefore, according to the commenter, emission limits need to be established within the capabilities and accuracy of monitoring systems, and when owners/operators purchase control equipment, they may add an operational margin in their specification and request for performance guarantees. The commenter believes compliance monitoring and measurement for the proposed new unit emission limits are of concern, and vendor guarantees may be problematic without the ability to consistently measure remaining pollutants at the low emission levels proposed.

Response to Comment 2: As more thoroughly discussed in 4A03 of this document, the new source limits have been revised in order to represent the representative detection level (RDL) instead of the MDL determined by a single source.

Comment 3: Commenter 18429 believes the EPA's proposed test methods are not adequate for the excessively low limits for new sources, including both Hg and HCl CEMS. The commenter references EPRI analyses. The commenter suggests the EPA complete a re-review of the limits and test methods for new units to provide a meaningful MACT with which new units can continuously comply. The commenter notes that consistent with CAA section 112(d), the emission limits must be measurable by current technology.

Response to Comment 3: In response to comments, the final rule allows the option to perform periodic stack measurement or monitoring for PM, HCl, HF, and non-Hg HAP metals. There is discussion elsewhere in this document of how the agency managed BDL data in analyzing the floor and developing emissions limits for this rule.

Comment 4: Commenter 17914 is concerned that available CEMS equipment is not accurate enough in commercial field applications to reliably report total PM at the proposed MACT emissions limit for new coal. The commenter states that for a supplier of new boilers and associated AQCS equipment, these extremely low limits present a significant challenge for them to provide performance guarantees in light of the inaccuracies of the reference methods for PM. The commenter notes that the proposed rule indicates no allowance was made for data collected at or below the MDL and instead a default value of the MDL was used, and suggests this logic would appear flawed, as setting a compliance limit that is only 2 times the MDL for the test method which could result in errors as high as 50%. The commenter references U.S. EPA "Review of National Primary Drinking Water Regulations: Analytical Methods - Reassessment of Practical Quantitation Limits, noting that the EPA guidance suggests a multiplier of 5-10 times the MDL for determining the PQL (in absence of sufficient inter-laboratory study data).

Response to Comment 4: In response to comments, the final rule does not have a total PM limit. The facilities also have the option of periodic filterable PM testing in lieu of the installation of PM CPMS. The EPA has also finalize alternative equivalent compliance options by establishing a total non-Hg metals limit and individual non-Hg metal limits.

Comment 5: Commenter 17621 performed an analysis of method sensitivity to evaluate the ability of test methods to measure HAP and surrogate parameters at the MACT limits, and includes a summary table to the test method adequacy in their comments (Table 2-1). The commenter notes that as the proposal also requires facilities to establish operating limits for some HAP based on initial performance tests, which would then become the effective emissions limits for that facility. According to the commenter, as those operating limits would be lower than the MACT limits, there may be additional restrictions on the use of test methods beyond those indicated in the table.

Response to Comment 5: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS and provides the option for periodic testing for non-Hg HAPs. Hg sorbent monitoring allows for sensitivities below the emission standards.

Comment 6: Commenter 18034 states the proposed emission limits for some of the pollutants are very near and in some cases significantly less than the documented MDL of the required emissions testing and monitoring methods and even contradict certain recordkeeping provisions, which makes it impossible for companies to demonstrate compliance with the emission limits. The commenter recommends the EPA bring the emissions limits into harmony with the capabilities of the prescribed methods and procedures for demonstrating compliance. The commenter provides specific examples for proposed Hg limits for new coal-fired EGUs under the greater than or equal to 8,300 Btu/lb subcategory.

Response to Comment 6: The proposed Hg limit for new coal-fired EGUs was measured within the calibration range of the analytical technique and met all QA/QC criteria of Method 30B in a 4-hour run.

Comment 7: Commenter 17715 notes that NIST traceable standards, gaseous oxidized standards traceable to NIST and agreed to standard Hg vapor curves are not available, and without them there will be non-uniform reporting of emissions.

Response to Comment 7: It is the EPA's position that the Interim EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators and the Interim EPA Traceability Protocol for Qualification and Certification of Oxidized Mercury Gas Generators both published on July 01, 2009 are adequate to establish the NIST-traceability necessary for mercury monitoring programs at this time. The major vendors of mercury CEMS have, for some time, been marketing elemental mercury calibration gas generators that are directly traceable to NIST elemental mercury reference standards. We agree with the commenters' point that NIST does not currently directly certify oxidized mercury gas generators. However, oxidized gas generator NIST traceability is established through the assessment of the individual components of the calibrator. The interim protocols for certifying mercury gas generators allow sufficient flexibility to certify the gas generators in an appropriate range from existing NIST traceable gas standards. The EPA does not believe it necessary to make available standard mercury vapor pressure curves in order to implement the mercury monitoring program set forth in this rule as the EPA's primary approach to NIST traceability for calibration gases is based on direct comparisons with NIST reference materials and standards.

Comment 8: Commenter 17790 believes the EPA should specify specific guidelines for analytical detection limits stack testing for non-Hg HAP metals and how to handle results that are below the detection limit.

Comment 9: Commenter 17800 believes the non-Hg metals data collected during the 2010 ICR showed reported detection limits for laboratory analysis that were highly variable even for data for the same metal and from the same laboratory. The commenter suggests the EPA specify minimum detection limits and procedures for combining front and back half fractions to report total concentrations in order to determine compliance on a consistent basis.

Response to Comments 8 - 9: The MDL for non-Hg metals will depend on volumes samples and the analytical finish used. Table 5 will be revised to specify the procedures for handling MDL results while adding up multiple fractions.

Comment 10: Commenter 17902 believes the EPA must allow for a margin of compliance when setting the final MACT standards as the measurements for Hg and other HAPS in the rule are completed at very low levels of detection, leaving a greater potential for error.

Response to Comment 10: As more thoroughly discussed in Section 4A03, the emission limits for new and existing sources were set at a minimum of three times the RDL to provide for measurement and process variability at low levels when the UPL based on the data was not greater than three times the RDL.

Comment 11: Commenter 17775 agrees that performance testing for units using CEMS should not be required any more frequently than every 5 years. The commenter also supports inclusion of a reduced testing provision for tests conducted more frequently. However, the commenter does not believe that the EPA has provided sufficient support for many of the testing requirements in this proposal. Moreover, the commenter does not believe that the 50 percent criterion is reasonable given the extremely low levels of the EPA's proposed limits. The commenter requests that the EPA remove this restriction. The commenter states the EPA has provided no reason for this restriction, or data suggesting that any source could achieve 50% of the proposed emission limits, some of which are established at or near the detection limit. The commenter does not understand how a source could test at a percent of the detection limit. The requirement that source and control device operation remain consistent with prior successful testing should be sufficient to ensure representativeness of the prior test(s).

Response to Comment 11: In the final rule, there is no requirement for periodic stack testing where a CEMS is used. The QA requirements for a CEMS, including Relative Accuracy Test Audits, are adequate to ensure that the CEMS data remain valid for purposes of determining compliance with the emission limits under this rule. The EPA disagrees and will retain the 50% criterion for reduced testing. Sources operating at low levels can show compliance with the 50% limit by increased sampling volumes. Also, the sources may opt to use CEMS or CPMS in lieu of the repeated periodic testing.

Comment 12: Commenter 17730 suggests the EPA specify minimum detection limits for laboratory analysis for all pollutants and provide procedures for calculating total PM combined concentrations of single metals and total non-Hg metals. The commenter notes that based on data collected in the ICR, the reported detection limits for laboratory analysis were highly variable even for data for the same analyte from the same laboratory. The commenter suggests that to determine compliance on a consistent basis, the EPA needs to specify minimum detection limits and procedures for total PM for combining the front and back half fractions to report total concentrations.

Response to Comment 12: The EPA disagrees that we should specify a prescriptive minimum detection limit for laboratory analysis of all pollutants. Minimum detection limits will improve with future technology and analytical techniques. Since total PM has been removed from the final rule, procedures for combining total PM are not necessary.

Comment 13: Commenter 18443 suggests Hg, PM and HCl CEMS should be used as compliance indicators and not compliance methods. The commenter notes that the precision and accuracy of the current continuous HAP emission monitoring is not field proven to reliable reflect actual emissions data. The commenter believes very low HCl, Hg and PM concentrations are difficult enough to measure using stack tests (as evidenced by the numerous values at or below detection levels in the ICR data set), and accurately measuring these concentrations with CEMS is nearly impossible. According to the commenter, to date Hg, PM and particularly HCl CEMs have not been designed to measure very low pollutant concentrations. The commenter believes that the EPA should recognize the limitations that these CEMS have and use them only as an indicator of compliance, not as a compliance method. According to the commenter, these shortcomings, when used in series to determine emission rates, will result in substantial monitor downtime and the potential for numerous non-compliance events.

Response to Comment 13: An Hg CEMS or an HCl CEMS are options for use as the performance test method for the applicable Hg and HCl emission limits. If a source is concerned about the use of these methods in such a manner, the rule provides for other options (sorbent trap monitoring for Hg and stack testing for Hg and HCl). There is no requirement to use a PM CEMS as a direct performance test method for the PM emission limit. The PM CPMS is used as an operating parameter monitoring approach to demonstrate compliance with a site-specific operating limit expressed in terms of the raw output of the PM CPMS. The operating limit aids in ensuring that the source is operated and maintained in accordance with good air pollution control practices to minimize emissions so that the source can continue to operate in compliance with the emission limit as demonstrated in a periodic stack test. The final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 14: Commenters 17316 and 17386 state that establishing HAP emission limits at the boundary of what can be detected by available analytic techniques does not seem reasonable and that the incremental benefits (HAP reductions) to be achieved by extending emission limits to such low levels, lying at the edge of detestability, do not seem justified.

Response to Comment 14: As further discussed in Section 4A, the emission limits are set at levels which EPA believes are consistent with the requirements of the CAA.

Comment 15: Commenter 18023 believes the EPA should not use data that is below the MDL to establish the MACT floor. The commenter states that despite not being able to "meaningfully quantify the concentration(s)," the EPA used data that was identified as being "below detection limit" (BDL) or "detection level limited" (DLL) when establishing the MACT floors. The commenter suggests this means that many of the new and existing source MACT limits are based on data that is unquantifiable. The commenter references the comments submitted by EPRI that discusses that using BDL and DLL data also caused several of the new source limits to be so stringent that they are actually below the applicable method sensitivity. The commenter recommends the EPA should only use values that are above the MDL in calculating the MACT floor.

Response to Comment 15: The EPA's treatment of the data is consistent with the recommendation. All data determined to be below the detection limit was treated as measured at the method detection limit for use in the floor. Further discussion of the treatment of BDL and DLL data can be found in 4A03 of this document.

Comment 16: Commenter 17821 states the EPA's effort to set emission limits for all HAP emitted by EGUs is greatly complicated by the fact that a number of HAP were emitted at levels at or below the reporting limits for the test methods required for collection of HAP emissions data during the ICR. The commenter cites *Amoco Oil Co. v. EPA*, stating that the legal history is that an emission limit must not be set below the quantification level of the method chosen for demonstrating compliance, and that if an emission limit is set below the quantification level, then as the court in *Amoco Oil* cautioned, the limit would be unenforceable. The commenter also cites a January 2011 memo in which the EPA acknowledged that measurements at levels below analytical detection and quantitation levels are associated with increased measurement uncertainty. The commenter provides additional discussion on quantitation limits and recommends that the EPA use quantitation limits rather than detection limits when establishing limits for the new standard.

Response to Comment 16: As further discussed in sections 4A03/4 of this document, we believe that the procedures used in managing BDL data in establishing the floor values and setting emissions limit and we have discussed this procedure in detail elsewhere in this document. The EPA is not setting standards below the detection limit so those comments are moot.

Comment 17: Commenter 17873 believes that the new source Hg limit is below the detection limit of any current or planned instrument, and even if a new unit could meet the limit, there is no way to assess compliance. The commenter suggests the EPA's proposed new source limit for Hg would act to ban the construction of new coal plants. According to the commenter, nothing in the CAA authorizes or mandates this result, and it has significant implications for the long-term energy security of the nation. The commenter believes the EPA should not be setting national energy policy through a CAA rulemaking.

Response to Comment 17: The Hg limit for new coal-fired EGUs was measured within the calibration range of the analytical technique and met all QA/QC criteria of Method 30B in a 4-hour run, meaning that current instruments can measure mercury emissions at the level of the emissions standards. The agency disagrees with the commenter's assertion that the mercury emissions limit for new sources would act to ban construction of new coal plants; on the contrary, at least one or more existing EGUs reported mercury emissions at or below the emissions limit for new sources, for values from existing units were used to establish the mercury limits in the rule.

2. Concerns with specific test methods.

Comment 18: Commenter 17711 notes several potential issues with the EPA Methods 5, 23, 26/26A and 29 as reference methods for measuring source emissions of PM, dioxins/furans, HCl, and Hg. The commenter notes that the extraction, processing, and analysis of samples can lead to random errors to the final measurement and provides examples such as where compound concentrations are inconsistent due to changes in fuel mix over time, contamination occurs, or improper instrument calibration or matrix interference.

Response to Comment 18: The agency disagrees with the commenter's view that potential issues with the listed EPA Methods renders them less than useful for this rule. The rule identifies potential problematic areas for the Methods, and provides alternatives, both within the Methods and through the use of other means to determine compliance. Should an EGU owner or operator believe the potential issues with emissions testing to be problematic, he or she can choose to use continuous emissions monitoring systems to demonstrate compliance. The EPA Method 23 is not required for the final rule. The EPA agrees that "extraction, processing and analysis" can lead to random error and variability that would not be seen due to the truncation of the data set at the MDL. This is the basis for the emission standards being set at no less than 3 times the RDL as discussed in the preamble and 4A03 of this document.

Comment 19: Commenter 17711 states that aside from a 1996 study by R. Shigehara, the commenter is not aware that the EPA has published any results from studies necessary to determine the detection and quantitation limits of its reference stack test methods nor that the EPA has even proposed a method for determining the values of these parameters of the reference methods. The commenter states that of the five test methods that were utilized to collect data for setting the proposed MACT standards and would be used to demonstrate compliance with the proposed standards, the EPA has provided the detection limits for only Method 29, and even in those cases no EPA reports are available to assess the validities of the detection limits specified with the test methods. According to the commenter, even in the absence of such reports, if one assumes that these values are correct and then applies the 3.18 Student-t multiplier for three samples to the detection limits, the estimated quantitation limit of Method 29 would be 1.8 μg/m3. An examination of the data in the EPA's MACT database shows that it includes measurements below these values. The commenter suggests that values below a method's quantitation limit should not be used to set emission standards.

Response to Comment 19: The EPA disagrees with the comment. The Method 29 detection limits published in the method only represent approximate estimates for each analytical technique to provide a guideline on choosing the appropriate analytical technique. The EPA Method 5 MDL was published with the promulgation of Method 5I. The Method 26 and 26A typical method detection limits were also published. As more thoroughly discussed in 4A03 of this document, the EPA disagrees that only values above the method's quantitation limit should be used.

Comment 20: Commenter 17725 provides a discussion regarding a caveat of Method 30B that allows for an alternative approach for quantifying low masses. The commenter notes the caveat allows for estimates for masses below the lowest point on the calibration curve (i.e., LOQ), but above the MDL. The commenter suggests this caveat is of significance because there are no ongoing quality assurance/quality control (QA/QC) requirements for the response factor mass estimates. According to the commenter, this fundamentally differs from masses that fall within the calibration curve; all points used in the generation of the calibration curve must be within ±10% of the expected value. Furthermore, according to the commenter, continuous calibration verification standards (CCVS) must be performed no more than every 10 field sample analysis and also be within ±10% of the expected value for the field samples to be considered valid. The commenter asserts that therefore, any masses and ultimately effluent concentrations that are determined using the response factor approach are not of the same quality or uncertainty a those determined by the calibration curve (i.e., masses above the LOQ). According to the commenter, all masses determined above the LOQ are of acceptable quality and a known uncertainty of ±10 percent, and conversely, masses determined using the response factor approach are of unknown quality and uncertainty, they are merely estimates.

Response to Comment 20: The agency agrees with the commenter that this could be a concern, especially in light of the low Hg concentration levels that may be measured under this rule. Therefore, we are proposing in a separate rulemaking an amendment to Method 30B that would lower the specified Hg concentration for which the tester must have his sample results within the calibration curve from 0.5 μg/dscm (current specification) to 0.01 μg/dscm. This will mean that in the future, concentrations down at least to 0.01 μg/dscm will be of known quality as described by the commenter.

Comment 21: Commenters 17725 and 18498 disagree with the EPA simply stating a generic MDL/LOQ for the entire Method 30B, as MDL and LOQ data collected vary among labs, analyzers and analysts. One commenter suggests that although the theoretically calculated MDL and LOQ has been shown to be as low as 2ng, in practice the QA/QC at that level is not obtainable. The commenters believe that in practice 10ng is a reasonable range for the LOQ to collect data of acceptable quality and known uncertainty (i.e., ±10 percent) and 5ng is pushing the envelope on the lowest LOQ that should be used when evaluating low level effluent concentration data (i.e., ≤ 0.1μg/m3). The commenters suggest the response factor approach is used for merely estimating masses below the LOQ, but above the MDL and should not be used when establishing an emission limit as the data of are of unknown quality and uncertainty. According to the commenters, it then follows for a typical ICR test (i.e., 2hr test run collecting 120l of volume) that effluent concentrations ranging between 0.04μg/m3 and 0.08μg/m3 are the lowest that can be reasonably be determined with acceptable quality and uncertainty.

Response to Comment 21: The EPA agrees that, in general, the response factor approach in Method 30B should not be used for estimating masses below the LOQ, but above the MDL when reporting emissions data for compliance determination as these data of are of unknown quality and uncertainty. It is the EPA's intent to ensure that reported Hg emissions data are of known and acceptable quality. In response, the EPA is about to propose an amendment to Method 30B that would lower the specified Hg concentration for which the tester must have his sample results with the calibration curve from 0.5 μg/dscm (the current specification) down to 0.01 μg/dscm. This will mean that in the future concentrations down to at least 0.01 μg/dscm will be of known quality. The EPA disagrees that effluent concentrations ranging between 0.04 $\mu g/m^3$ and 0.08 $\mu g/m^3$ are the lowest that can be reasonably be determined with acceptable quality and uncertainty. In fact, recent testing conducted as part of the Utility MACT ICR demonstrated that an average stack Hg concentration of 0.01 $\mu g/m^3$ could be measured as part of a triplicate 4 hour emissions test with all Method 30B performance criteria being met.

Comment 22: Commenter 17725 believes the EPA Methods 26A and 26 have proven to be reliable stack testing methods and produce high quality results; however, there are limitations with each method with regards to detection limits. The commenter questions if either method can consistently provide reliable data for compliance determination for the proposed limit as factors such as blank contamination, positive and negative biases due to flue gas interferences, and analytical errors raise questions. The commenter believes the proposed HCl emission limit of 0.00030 lb/MMBtu is very low with respect to the in-stack detection limit for HCl. The commenter notes that based on multiple sites that underwent testing during the ICR, in-stack detection limits were in the area of 0.000050 lb/MMBtu, and the ICR required very long run times of 180 minutes for increased detection. According to the commenter, even with the long run times, the proposed emission limit was only six times greater than the in-stack detection limit for the HCl. The commenter asserts that in theory, HCl can be measured at this level but the issue is the ability to produce reliable, repeatable, high quality results this close to the detection limit.

Response to Comment 22: We agree that there are method detection level capability differences between Methods 26 and 26A and both are allowed by the rule. The source has the option to choose the method and the required sampling periods consistent with expected emissions levels and the procedures for managing method detection levels in determining compliance.

Comment 23: Commenter 17621 suggests that Method 29 does not have adequate sensitivity to measure antimony accurately at the alternative individual metal MACT limits for existing units. The commenter provides a table (Table B-1) which shows that at the individual metals MACT limits for new coal EGUs, most metals would not be measured accurately. The commenter notes that ASTM D6764-02 states a lower limit of quantitation for Hg of 0.5 µg/m3, which corresponds to a stack emission for coal-fired units of approximately 0.45 lb/Tbtu and this level of sensitivity is adequate to measure Hg at the MACT limit for existing coal units, but not at the limit for new units. The commenter also discusses that analytical detection limits do not consider the many sampling- and matrix-related factors that can raise detection limits at the stack. However, the commenter believes method sensitivity could also be better in practice than indicated in Table B-1 due to improvements in instrumentation and collection of larger sample volumes than required by the ICR. According to the commenter, therefore, this comparison was not given as much weight as the ICR results in the determination of method adequacy.

Response to Comment 23: The individual metal MACT limits have been reassessed to ensure that they are no less than three times the RDL including the data collected with Method 29. ASTM 6674-02 has been removed from Table 5 for use with compliance determination to ensure adequate sensitivity for compliance due to the sample volume restrictions of the method. The EPA agrees that method sensitivity will be improved in the future with improvements in instrumentation and the allowance to run higher sample volume than required minimums listed in Tables 1 and 2.

5A05 - Testing/Monitoring: Operating parameter monitoring

Commenters: 17197, 17316, 17383, 17402, 17622, 17627, 17638, 17675, 17677, 17681, 17689, 17696, 17705, 17715, 17716, 17718, 17725, 17730, 17736, 17740, 17752, 17754, 17757, 17758, 17761, 17767, 17772, 17775, 17776, 17790, 17795, 17798, 17800, 17804, 17805, 17807, 17808, 17813, 17816, 17820, 17821, 17856, 17868, 17870, 17873, 17876, 17881, 17886, 17902, 17912, 17914, 17923, 17925, 17928, 18014, 18015, 18021, 18025, 18037, 18426, 18428, 18429, 18437, 18498, 18539, 19033, 19114, 19120, 19121, 19536, 19537, 19538, 18023

1. Objections to parametric operating limits for units with CEMS (section 63.10007(c)).

Comment 1: Numerous commenters (17383, 17402, 17622, 17627, 17638, 17675, 17677, 17681, 17689, 17696, 17705, 17715, 17716, 17718, 17728, 17730, 17736, 17740, 17758, 17761, 17767, 17772, 17775, 17798, 17807, 17808, 17813, 17856, 17868, 17873, 17876, 17886, 17902, 17914, 17923, 17925, 18015, 18025, 18037, 18428, 18429, 18437, 18539, 19114 19120, 19121, 18023) oppose the proposed control-device-specific operating limits for demonstrating ongoing compliance on units that are equipped with CEMS because these commenters believe such parametric limits are duplicative to the MACT floor emissions limits that EGUs must meet, unduly burdensome, decrease operational flexibility, make it difficult to operate control equipment at optimum efficiency, and/or inconsistent with longstanding EPA policies under 40 CFR part 64.

Comment 2: Several commenters (17775, 17868, 18539, 19120) state that proposed section 63.10007(c) is unclear because it does not indicate whether every affected facility is subject to the requirements to establish parametric operating limits, and recommends that the final rule should make it clear that units with CEMS are not required to perform parametric monitoring or take operating limits. Commenters believe that the purpose of operating limits is to determine compliance between performance tests and that units with CEMS or sorbent traps would not require such limits. Commenters 17758 and 17868 state that the EPA has not provided justification for requiring units with CEMS to also perform parametric monitoring for the same HAP or surrogate.

Comment 3: Commenter 17868 states that section 63.10022(b) provides that if you demonstrate compliance through performance testing you must establish operating limits in Table 4. According to the commenter, since all EGUs must demonstrate initial compliance with each emission limit “through performance testing,” and the proposed rule defines “performance testing” to include the first 30 operating days of CEMS data, the proposal appears to require that EGUs meet operating limits for all relevant control devices and load regardless of the “performance testing” option they choose (see, e.g., proposed section 63.10005(a) and Table 5 (including stack tests, CEMS, and LEES in the list of “performance testing” options)). The commenter observes that the other provisions cited in section 63.10011(b) provide little clarification, that proposed section 63.10007 does not discuss applicability, and that with the exception of the filterable PM limit applicable to units using PM CEMS, Table 7 does not distinguish between compliance options; instead, Table 7 refers to various parameters depending on which control device “your operating limits are based on.” The commenter also states that section 63.10011(c)(6) addresses fuel sampling, not operating limits and that section 63.10011(b)(6), the provision the EPA likely meant to cite, refers only to control devices and not compliance options. Commenter 17868 concludes that the preamble discussion contains numerous inconsistent statements and no rationale by which one could determine the EPA’s intent with respect to these operating limits for units using CEMS and sorbent trap monitoring systems.

Comment 4: Commenter 17718 states that the EPA should require no proof of compliance beyond a properly calibrated and installed CEMS and that the EPA should revise both the language and tables in the rule to clarify its intent as it relates to CEMS used for demonstrating compliance. According to the commenter, HCl CEMS are not commercially available or adequate for in-stack measurements from electric utility units and likely will not be available by the compliance date of the rule. The commenter asserts that sources will be forced to either take a fuel limit or an operating parameter limit and that the fuel analysis limit is impractical as it relates to a coal-fired facility because of chlorine variability that is inherent in coal. that it will be impossible to control fuel deliveries in such a manner as to eliminate the possibility of burning coal with chlorine content above that which was used during compliance testing.

Comment 5: Commenter 18428 states that the preamble discussion contains numerous inconsistent statements and no rationale by which one could determine the EPA's intent with respect to these operating limits for units using CEMS and sorbent trap monitoring systems. For example, according to the commenter, the EPA suggests in the following statements that operating limits apply only to units without CEMS:

- IGCC units or units combusting coal or solid oil-derived fuel with PM controls but not using PM CEMS to demonstrate continuous compliance would also be required to conduct parameter monitoring and meeting operating limits established during performance testing.
- The second option that we are proposing would be for units without SO_2 or HCl CEMS but with SO_2 emissions control devices. For these units, parameter operating limits established during performance testing, would be monitored continuously, along with the already-mentioned frequent (every 2 months) HCl emissions testing.
- When a performance test is conducted, we are proposing that parameter operating limitations be determined during the test. Performance tests to demonstrate compliance with any applicable emission limitations are either stack tests or fuel analysis or a combination of both, " ... units equipped with devices that control PM and HCl emissions but do not elect to use CEMS, would determine suitable parameter operating limits ..."

The commenter notes that in another statement, the EPA suggests that all EGUs with PM controls must establish operating parameters, whether or not they have CEMS:

- " those EGUs with PM emissions controls, without HCl CEMS but with HCI control devices, or for LEE, we are proposing that you monitor during initial performance testing specified operating parameters that you would use to demonstrate ongoing compliance."

Comment 6: Commenter 17775 asserts that the EPA must recognize that there are limitations on the conditions under which the EPA can require EGUs to establish operating parameters because to comply with CAA section 112, the EPA assessed capabilities of controls under conditions specified in the 2010 ICR and established compliance testing and compliance assurance requirements consistent with that assessment, and the EPA has proposed continuous monitoring, initial stack testing, or periodic fuel analysis that it presumably believes are consistent with that assessment.

Comment 7: Several commenters (17775, 17902, 17925, 18539) state that as long as an EGU is complying with one of the options for demonstrating "continuous compliance," there is no basis to allow the Administrator to specify some other test be conducted under some other set of conditions.

Comment 8: Commenters 17740 and 17808 are concerned about adding unnecessary costs for sources demonstrating continuous compliance via CEMS and is also concerned that the proposed requirements will duplicate existing requirements in title V CAM conditions.

Comment 9: Commenters 17873 and 17886 express concern that the secondary operating requirements also create a "double jeopardy" compliance risk: as long as the EGU MACT includes these limits, a unit could be in compliance with the underlying emission standard (and therefore protecting the environment) but find itself out of compliance with a related operating limit.

Comment 10: Several commenters (17775, 17808, 17813) believe that it is inappropriate to hold EGUs to limitations on the operations of its controls set during brief performance testing periods that may not reflect the full range of operating conditions that can comply with the emissions limits. The commenters express the need to be able to make adjustments based on coal variability and other operating conditions that can differ from the conditions occurring during performance tests. Furthermore, the commenters express concerns that many coal units are utilized to generate variable intermediate loads to meet variable electrical power demands and thus, do not operate in the steady state associated with normal performance tests. Commenter 17716 contends that such normal load variations are inconsistent with the proposed requirement to establish a minimum pressure drop and liquid injection rate on a wet PM scrubber because normal pressure drops at low load will result in the reporting of deviations compared to pressure drop limitations set at high load. These commenters advise that when variable load operations are combined with variable coal properties, operating parameters can differ significantly from steady state performance test conditions. These commenters contend that based on their operating experience, as long as the unit is in compliance as measured with the CEMS, there is no need to track or limit operating parameters because they vary by design. Commenter 17705 notes that the EPA has recognized many times that CEMS represent the best available method for tracking compliance with emissions limitations at a regulated source, and the commenter refers to provision of 40 CFR part 64 (the CAM rule) that state when a CEMS is specified by the applicable standard, the requirements of part 64 do not apply to that emission standard. The commenter cites the following reference to CEMS from the preamble to the CAM rule: "The EPA believes that these types of monitoring are preferable from a technical and policy perspective as a means of assuring compliance with applicable requirements because they can provide data directly in terms of the applicable emission limitation or standard."

Comment 11: Commenter 19121 states that they support the use of parametric and fuel data to show compliance when outlet monitoring is not available. However, the commenter states that for those HAP where a numerical limit and a monitoring method is set, other secondary operating restrictions should not apply. According to the commenter, such an approach would severely curtail operating flexibility and limit demand response.

Comment 12: Commenter 17767 states that it is unreasonable to assume that ongoing compliance would meet the operating parameter average if compliance could not be met during the compliance stack test. According to the commenter, the proposed rule makes no mention of the tolerance of operating parameter limits set during initial compliance testing for any pollutant or surrogate. The commenter asserts that if an average of the tests runs is used to set a limit, then even the initial passing compliance test would have periods of noncompliance during the runs with parameters outside the final averaged target parameters.

Comment 13: Commenter 18021 states that one set of operating conditions do not produce operating limits that are properly reflective of systems' capabilities. The commenter notes that current operation must be flexible enough to meet not only load swings but also future regulations.

Response to Comments 1 - 13: The rule does not require monitoring operating limits where a CEMS is used for the applicable standard. If a source has PM control equipment and uses a PM CPMS based operational limit, no control device monitoring is required. The same is true for HCl or SO_2 controls for coal-fired and other solid fuel affected units. The only additional operating parameter requirement will be for liquid oil-fired EGUs whose owners or operators choose to use quarterly acid gas emissions testing. The appropriate parameters, monitoring method, QA/QC provisions, and data reduction requirements will be established in a site-specific monitoring plan; please see the final preamble for further discussion. With respect to the need for variability in establishing parameter limits because of load changes or changes in fuel, the rule provides for establishing different operating limits based on different loads. Also, see the response to the following comments about establishing "deviations" from operating limits.

2. Duplication of pollutant testing.

Comment 14: Commenter 17716 states that the EPA has established alternative compliance limits for various HAP groups, providing sources with flexibility to measure the PM limit, limits for individual metals, or a total non-Hg metals limit to establish compliance for metal HAP and to monitor SO_2 or HCl for acid gas HAP. The commenter states that the proposed rule requires stack tests not only for the pollutant but also for the surrogate. According to the commenter, performance tests should be matched to either the pollutants or the surrogates chosen by the source to show compliance, the extra tests are redundant.

Response to Comment 14: The EPA agrees that if the source elects to comply with an surrogate standard such as filterable PM instead of the alternative equivalent total or individual non-Hg HAP metals, then the only performance test to be performed is the test to show compliance with the emission standard that applies (in this example, the filterable PM limit). The final rule clarifies this position.

3. General objections to enforceable parametric operating limits (section 63.10007(c)).

Comment 15: Multiple commenters (17402, 17622, 17675, 17677, 17681, 17696, 17705, 17715, 17716, 17728, 17730, 17775, 17800, 17808, 17873, 17912, 18023) find that the proposed requirements for operating parameters at section 63.9991(a)(2) particularly problematic because the proposed definition of "deviation" includes operating limits, but the commenters feel operating limits should not be a reportable deviation since they are indicators of compliance and not emission limitations.

Comment 16: Multiple commenters (17730, 17775, 17800, 17820, 17868, 17912, 17914, 18428) believe that the proposed usage of parametric operating limits deprives sources of the use of any control device margin, and allows enforcement for events beyond the operator's control. Commenters state that the EPA's current proposal is based on the faulty assumptions that the values of the parameters identified by the EPA have a direct relationship to the level of emissions, and that exceedances of those limits therefore indicate an exceedance of the emission limit. The commenters' view of operating parameters is that to the extent possible, operators will contract for control equipment designs that provide a "margin of compliance" with applicable emissions limits. According to the commenters, in addition to reducing the possibility of an exceedance of the limit, this margin is intended to provide flexibility for the source to account for inevitable control equipment or operational problems. The commenters believe that under the proposed parametric monitoring regime, sources with a margin of compliance will lose part of that margin of compliance if they conduct performance testing under normal operations because they will establish operating limits that would require them to continue to over-control forevermore. The commenters suggest that the only way such sources could avoid surrendering whatever margin of compliance they have would be to deliberately reduce performance of their controls to attempt to generate the least stringent operating limits consistent with achievement of the applicable emission standard. The commenters conclude that the proposal encourages sources to focus their attention on learning how to manipulate operations to allow testing as close as possible to their emission limit by reducing performance of their controls. These commenters generally believe that the parameter ranges in Table 4 must be established as corrective action levels, not enforceable operating limits and each of these commenters recommends that the final rule adopt provisions similar to those for CAM under 40 CFR part 64 for assuring continuous compliance with the MACT standards rather than the proposed provisions for parametric monitoring. Commenter 17775 refers the EPA to an attached report by McRanie Consulting entitled "Comments on the Proposed Utility MACT Rule - Operating Parameters" (July 2011). Commenter 17675 states that other MACT standards like subparts LL and MM take the right approach to parametric monitoring. The commenter states that these standards require that corrective actions are taken to respond to parameter excursions and that the failure to take corrective action is a violation.

Comment 17: Several commenters (17675, 18037, 18429) generally believe that the CAM approach (that allows operators to propose excursion levels and response requirements for approval by the title V permitting authority) is a proven method of obtaining reasonable assurance of compliance while recognizing the wide variations in parametric ranges that can occur during operating periods that are in compliance with the underlying emissions limit.

Comment 18: Commenter 17912 states the operating parameters may push events beyond the operator's control into an unavoidable enforcement posture. According to the commenter, for example, for compliance with the proposed total particulate emission limit for new and reconstructed EGUs, the proposed emission limit is 0.050 lb/MWh as measured by a manual stack test. However, the commenter asserts, if a CEMS for filterable particulates is used to demonstrate compliance, then, to be in compliance on a continuous basis, the owner or operator must "[m]aintain the PM concentration (mg/dscm) at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the total PM emissions limitation." The commenter states that to demonstrate continuous compliance, the EPA proposes to average the emissions measured by the CEMS over 30 days for reporting purposes. Nowhere, however, according to the commenter, does the agency explain how an emission limit derived from a single, one-hour measurement can reasonably be expected to account for the all of the variable conditions that may occur during any given day, let alone a month or a year. The commenter states that federal courts have explained that an emission standard is "'achieved in practice' [when it] is interpreted to mean 'achieved under the worst foreseeable circumstances'" and cites *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999).

Comment 19: Commenter 17873 states that in setting operating limits the EPA unreasonably extends its authority beyond establishing the appropriate emission standard to governing the way a company operates a unit to meet a standard. According to the commenter, the prescribed operating parameters (scrubber pH, etc.) and averaging method used to demonstrate compliance with those limits create a secondary and overlapping regulatory obligation likely to result in excessive control process cost and material waste.

Comment 20: Commenters 17873 and 17740 state that operating limits make it difficult to bring additional renewable resources on-line. Commenter 17873 states that designing operating strategies to include multiple process set points for control equipment at different loads is difficult. The commenter notes that the ability of its coal generating units to change load quickly and efficiently is critical in accommodating variable wind energy. The commenter is concerned about the adverse effect on grid integration due to such additional plant operating constraints at the same time the company is supporting significant renewable energy penetration on its system.

Comment 21: Commenter 17902 states that the deviation of operating limits does not necessarily indicate that an emission limit has been exceeded, and in certain instances, could even suggest lower emissions (such as increased pressure drop for a baghouse control). According to the commenter, due to the stringency of the proposed MACT emission limits for EGUs, companies will not have an option to allow air pollution control equipment to operate below optimal levels or in a manner that would jeopardize compliance. The commenter recommends that the operating limits should only be applied in this rule as a work practice standard with deviations requiring investigation and corrective action as appropriate or necessary, but should not be considered non-compliance. The commenter further notes that this approach should be applied along with revising the compliance demonstration measurement to a 12-month rolling average basis for the applicable MACT emissions limits in Table 1 or Table 2.

Comment 22: Commenter 17982 recommends that, instead effectively setting enforceable site-specific operating limits that would have to be met at all times in addition to the emission limit for the surrogate, the EPA should allow reasonable, flexible alternative compliance demonstration options, including less frequent periodic stack tests – no more often than annually – and longer averaging times. According to the commenter, it may be difficult to meet these site-specific limits at all times under all operating conditions.

Comment 23: Several commenters (18023, 1775, 17800, 17821, 17868) state that a CAM approach has already been upheld as sufficient to satisfy the CAA's requirements for demonstrating continuous compliance in *NRDC v. EPA*, 194 F.3d 130, 135–37 (D.C. Cir. 1999).

Comment 24: Commenter 17705 states that no bases for the proposed parameters in Table 4 are presented in the technical support documents. Commenter 17705 adds that the EPA should not consider enforceable limits on control device operations unless the agency clearly demonstrates this is the only means of assuring compliant emissions. Commenter 17705 states that establishing the appropriate parametric limits must be done on a case-by-case basis as allowed under CAM rules.

Comment 25: Several commenters (17725, 17808, 18025) state that the proposed rule is not clear regarding what the required response action would be in the event that a unit violated its parameter operating limits, and the commenter suggests that a facility must initiate a corrective action to address the excursion similar to what is required in 40 CFR part 64 for CAM.

Comment 26: Commenter 17716 recommends an alternative approach to establishing representative control device operating ranges based on a statistical analysis of historical operating data during periods when the control device was operating properly.

Comment 27: Commenter 18023 takes exception to the stated assumption in the preamble that a baghouse or ESP can meet the proposed PM limits and the associated site-specific operating limits continuously because under the rule, sources will not know the design criteria for the operating limit until after an initial compliance test that will not take into consideration plant variability. Therefore, according to the commenter, it is unclear what control technologies will be necessary to meet the site-specific limit continuously. Commenter 18023 states that the site-specific limit is completely unworkable and must be removed and that even if the EPA refuses to remove the site-specific limit, the EPA must account for the added costs and burdens sources will inevitably encounter trying to meet site-specific limits.

Comment 28: Commenters 17870 and 18025 state that units with appropriate CAM plans and units operating CEMS should not be required to have additional monitoring requirements.

Comment 29: Commenter 17776 states that the inclusion of operating parameter limits in the proposed rule effectively lowers the numerical MACT floor. According to the commenter, it makes little sense to set a MACT floor then establish a mechanism to tighten the limit. Likewise, asserts the commenter, with a mandated monitor in place giving continuous, real-time readings in the units of the standard, the collection of control parameters for the purpose of compliance determinations is burdensome, but more importantly, completely unnecessary. The commenter states that in contrast, if the agency has confidence in the operating limits as a mechanism of compliance, then the mandated PM monitors are not necessary. According to the commenter, it should be noted that Hg and SO_2 CEMS data was deemed sufficient by the rule to assure compliance without the use of operating parameter limits.

Response to Comments 15 - 29: The EPA believes that continuous monitoring in the form of CEMS, sorbent traps, or CPMS is needed or that frequent emissions testing is needed to ensure ongoing compliance with this rule. In order to minimize costs and reduce burden, the rule has removed most operating parameters except for: (1) the owner-defined signal from the PM CPMS, which remains as an operating limit for those owners who choose to use PM CPMS; and (2) for acid gas emission limits, an owner-defined parameter monitoring approach for liquid oil-fired EGUs that do not use the fuel moisture certification approach, and do not use an HCl or HF CEMS, but instead rely on quarterly emissions testing. See the final preamble for further discussion. We have not required any other control device parameter monitoring in the final rule. While we recognize the importance of continued control device performance to ensure emissions minimization, we are aware that other rules that apply to these units - including but not limited to the operating permits rule, the compliance assurance monitoring rule, and the new source performance standards – already require ongoing parameter monitoring. Those rules will remain in effect, so additional imposition of operating limits on those units would be redundant. The limited operating limit requirements in the final rule address options (such as the PM CPMS in lieu of quarterly testing) or the potential gaps for liquid oil-fired units.

4. Requests to make parametric monitoring requirements more like Compliance Assurance Monitoring (CAM) Program.

Comment 30: Numerous commenters (17402, 17622, 17638, 17715, 17716, 17718, 17725, 17736, 17757, 17775, 17804, 17808, 17816, 17820, 17821, 17856, 18014, 18025, 18037, 18428, 18429, 18498, 18023) generally suggest that the final rule should incorporate more flexibility in setting parametric monitoring ranges similar to the existing CAM program. These commenters suggest the following specific revisions to proposed parametric monitoring provisions:

1. Several commenters (17716, 17725, 18498) state that some of the proposed parameters are either unnecessary, inappropriate, or could otherwise be substituted with parameters that are already monitored; for instance, wet scrubber parameters could be simplified based on scrubber pH and a calculated liquid-to-gas ratio, where gas flow is measured using an existing stack flow monitor and liquid injection rate is estimated based on the number of recycle pumps in service. According to the commenters, for ESP-equipped units, the use of total power may not be representative of PM emissions since removal efficiency is dependent on where the power is applied in the control device. The commenters suggest that other alternatives might include the use of an ESP model for predicting performance or specifying a minimum power level within each gas path. The commenters state that these examples demonstrate other monitoring alternatives that provide a reasonable assurance of compliance while allowing operators to implement more cost effective monitoring programs.

2. Multiple commenters (17402, 17715, 17689, 17808, 18037, 18539, 19114) believe that the EPA should revisit the way operating parameters are set during performance tests that are typically completed during high-load, steady-state conditions because the operating parameters captured during these tests may not represent the variability of day-to-day operations across the full range of operating loads. Commenter 17808 recommends that units with appropriate CAM plans should not be required to have additional monitoring requirements. Commenters (17715, 17718, 17736, 17757, 17816, 17856, 18037, 18539, 19114) express concerns with operating limits changing every 2 months based on the most recent performance test and the challenges of continuously revising operating procedures and alarm points. The commenters are concerned that sources will have no confidence that they will be able to demonstrate compliance over the full range of operating conditions that are normal for the source, and permitting authorities will have an impossible task to track different sets of operating limits for each unit in their jurisdiction.

3. Multiple commenters (17402, 17718, 17627, 17736, 17757, 17816, 18037, 18539, 19114) believe that as currently proposed, units would be constrained by unachievable operational parameters because the set of operating limits that a unit measures during its first performance test would be its maximum operating limits. According to the commenters, subsequent performance tests would further ratchet down operating parameters until they are no longer achievable during a 30-day or annual averaging period. The commenters state that control equipment operating characteristics during full load testing will not be suitable to monitor low load performance.

Commenters 17775 and 17868 state that even the "detuning" of a control device during performance tests will not ensure associated operating limits are necessary for compliance with the underlying emissions limit. Several commenters (17775, 17800, 17820, 17821, 17868, 18428) add that the EPA has previously recognized in the context of the NSPS and the CAM rule, "many sources operate well within permitted limits over a range of process and pollution control device operating parameters," and requiring sources to continuously maintain parameters that "happened to exist" during the most recent performance test may not be "possible or wise." 62 FR 54,900, 54,907, 54,926-27.

Multiple commenters (17718, 17775, 17800, 17820, 17821, 17816, 17868, 18428) state that the proposed control device parameters do not necessarily have a direct relationship to emissions but instead are interrelated with various parameters so that a single parameter may vary widely with little effect on emissions. The commenters acknowledge that the proposed provision of a 10% difference from the average tested value recognizes some of the normal operational variability of control devices, but believes the 10% margin will not be sufficient in some cases. The commenters conclude that without a clear correlation between the proposed operating parameters and emission limits, imposition of those values as enforceable limits unreasonably restricts operations and subjects operators to potential enforcement without any reliable evidence of emissions exceedances.

4. Commenter 17402 recommends that the operating limit should be based on the least stringent of the three minimum performance test runs and not the average of the runs (assuming, of course, that all three test runs demonstrated compliance with the MACT emission limits) because this would help account for real-world variability in operating parameters and would assure compliance because this testing certifies that when those (least stringent) operating parameters are met, the facility still meets the MACT limits. Moreover, the commenter believes, as long as the facility is in compliance via a certified CEMS or stack testing, there is no need to track the instantaneous values of operating parameters.

5. Commenter 17402 states that the normal variability of operating conditions further suggests that greater flexibility is needed for operators to substitute the EPA's proposed parameters, some of which

are unnecessary or inappropriate, with parameters that are either already monitored by the facility or parameters that would allow the EGU to implement more efficient monitoring. The commenter suggests that the required parameters proposed for wet scrubbers could be simplified to simply scrubber pH and a calculated liquid-to-gas ratio, where gas flow is measured using an existing stack flow monitor and liquid injection rate is estimated based on the number of recycle pumps in service. The commenter advises that FGD pressure drop varies with load and the number of recycle spray pumps that are in service, and therefore, the absorber pressure drop is not a good indicator of FGD performance. The commenter also advises that the proposed parametric requirements for ESPs (to establish minimum hourly average secondary voltage and secondary amperage and calculate the total secondary power input measured during the three-run performance test) fail to take into account which fields are being powered and where in the precipitator they are located. The commenter further advises that the appropriate secondary power will also vary with fuel and load making a minimum level set at a full load test inadequate to assure compliance at all loads.

6. Multiple commenters (17402, 17627, 17757, 17821, 18023, 18037, 18539, 19114) refer to existing requirements under 40 CFR part 64 commonly known as CAM plans in title V permits and state that the final rule should use the CAM program as the basis for parametric monitoring plans. The commenters suggest that source operators should be able to rely on this existing framework, and to work with permitting authorities to develop a set of parameters that make sense for the facility and its control configuration. Commenters (17402, 17627, 17757, 18539, 19114) state that CAM plans were specifically developed to assure PM limit compliance through the measurement of opacity even though opacity is not a direct measurement of PM, but permitting authorities recognize opacity as an indicator of control device performance, and there are approved plans that have formally documented the appropriate use of this indicator in an ongoing monitoring program.

7. Several commenters (17402, 17725, 18014, 18498) state that normal variability of operational parameters should be taken into consideration in the EPA's proposed procedures for establishing the compliance ranges. According to the commenters, the EPA proposes that EGUs would be required to set parameters based on 4-hour block averages during compliance tests and would demonstrate continuous compliance by monitoring 12-hour block average values below or above the lowest or highest 1-hour average measured during the most recent compliance test. The commenters do not believe that this approach adequately accounts for variability due to normal operation in some cases because (for example) the requirement to maintain a minimum pressure drop and liquid injection rate on a wet PM scrubber will result in the reporting of deviations during low generating loads. The commenters provide as another example the requirement to maintain sorbent injection rate at the rate established during the compliance test and state that such a requirement may result in the unnecessary reporting of deviations when these units fire lower pollutant-containing fuels. The commenters suggest that an alternative approach for establishing a more representative set of normal control device operating ranges might be a statistical analysis of historical operating data during which the control device was operating properly (no malfunctions). According to the commenters, the resulting operating limits could be discreet upper and lower bounds on certain operating parameters or a correlation between the control device operating parameter and one or more boiler operating parameters. If operating parameters are required, variability must be addressed. Therefore, one commenter recommends that the EPA should increase the averaging period from 12-hour block averages to 30-day rolling averages.

Similarly, other commenters (17808, 17870, 18025) state that setting an unreasonable operating limit that fails to reflect the full variability of the plant's operating conditions could damage the control technology. For example, according to the commenters, the proposed rule requires a plant operator to measure the voltage and current of each ESP collection field during each Hg, PM, and metals performance test, and the average of the three minimum hourly values would then be used to establish a unit's site-specific minimum voltage and current operating limits for the ESP. According to the commenters, maximizing power input and electric field strength will generally maximize ESP collection efficiency and plant operators need a degree of flexibility to balance the power input to the ESP in order to avoid serious damage to the system and downtime. The commenters note that power input to an ESP is dynamically controlled by an automated voltage control system to maximize power levels while avoiding sustained arcing or sparking between the electrodes and the collecting plates, which can damage the ESP, including the transformer-rectifier and other components in the primary circuit and that automatic voltage control varies the power to the transformer-rectifier in response to signals received from sensors in the precipitator and the transformer-rectifier itself. According to the commenters, power levels will vary depending on the amount of moisture in the air, accumulated ash levels, and other factors, and as result, sustaining a minimum voltage and current level may not be possible or appropriate at all times, and could damage the control technology.

8. Several commenters (17775, 17800, 17821, 17868) state that sources are in the best position to determine what parameters and levels are consistent with compliance. According to the commenters, in many cases, multiple parameter relationships or supplemental operational data will provide a higher level of compliance assurance than the level that happens to be measured during a discrete performance test. The commenters assert that this is particularly true for sources with a significant margin of compliance (see EPA-HQ-OAR-2002-0058-0413, Attachment C at 4). The commenters recommend allowing extrapolation of parameter data to preserve operational flexibility and avoid repeated testing. According to one commenter, attempting to establish "worst case" test conditions on a scrubber or multi-section ESP, where the possible combinations of parameters are numerous, would at the least be difficult and could be impossible without a major research effort. The commenters assert that allowing extrapolation of results avoids the necessity of repeated testing. The commenters note the a similar approach has been used in CAM protocols for ESPs allowing extrapolation up to 1.25 times the recorded value for measurements at less than 80% of the applicable limit. Several commenters (17775, 17800, 17820, 17821, 17868, 18428) recommend a CAM-like approach where once established parameter would be monitored for deviations that would triggers corrective actions. The commenters note that while the parameter range may in some cases be similar to the minimum values that would be established under the proposed rule, allowing sources to respond with corrective action (rather than simply record exceedances and report deviations) achieves the intended result without subjecting sources to potential unreasonable enforcement.

Response to Comment 30: As noted above, the rule does not require monitoring operating limits where a CEMS is used for the applicable standard. With respect to the need for variability in establishing parameter limits because of load changes or changes in fuel, the rule provides for establishing different operating limits based on different loads. Note that the ability to use parameter monitoring is a choice made by the owner or operator. Where parameter monitoring is chosen, we believe that continuous monitoring is needed to ensure ongoing compliance with this rule. As mentioned earlier, we require performance tests to demonstrate compliance with emission limits; we then use operating limits to ensure the source is operating similarly to how it was operating when it completed a successful performance test. Operating limits are not direct measures of emissions but provide a measure of fuel characteristics and control device performance and are established as enforceable operating limits routinely in NESHAP standards. You are also able to petition the Administrator for approval of an alternative monitoring plan under section 63.8(f) of subpart A of Part 63. This would include the possibility of adapting existing CAM plans that may rely on different parameters. Finally, we agree with commenters that collecting continuous data, transforming it to 1-hour averages, and then calculating a 30-day rolling average based on those 1-hour averages should address any variability concerns;

therefore the rule now contains a 30-day rolling average for the PM CPMS parameter. For acid gas emission limit compliance at liquid oil-fired units that use quarterly testing to demonstrate compliance, you will propose a site-specific operating parameter monitoring plan for your facility that should include the appropriate monitoring methods, QA/QC, and data reduction specifics for your unit. See the final preamble for further discussion.

5. ESP total secondary electric power (TSEP) requirements (section 63.100010(h)(2)(iii)).

Comment 31: Several commenters (17402, 17715, 17775) express concern about proposed requirements under section 63.100010(h)(2)(iii) for EGUs that have an operating limit requiring a total secondary electric power (TSEP) monitoring system on an ESP. Commenter 17402 requests that the EPA clarify how secondary power is calculated and if power is calculated on a field-by-field basis or across the whole ESP. Commenter 17715 states that this parameter fails to take into account which fields are being powered and where in the precipitator they are located. Commenter 17402 advises that under the EPA's proposal, this monitoring will be problematic because ESP power and PM collection efficiency vary by ESP configuration, fuel quality (coal sodium content), ash resistivity, number of electrical and mechanical fields, plate alignment, gas flow distribution, gas temperature, particle size and chemistry, rapper/vibrator settings, and air in leakage. The commenter has observed ESP power fluctuations of 20 percent during steady-state operation, and during startup and shutdowns, the ESP power shows even greater fluctuations–as high as 83 percent from high to low load. Commenter 17715 states that a TSEP minimum level set during a full load test is inadequate to assure compliance at all loads.

Comment 32: Several commenters (17775, 17800, 17868, 18428) request that the agency review the discussion on ESP performance in a report by McRanie Consulting entitled "Comments on the Proposed Utility MACT Rule - Operating Parameters" (July 2011) that was attached to their comments, because the report explains why proposed section 63.10011(b)(6)(iii) is flawed. According to the commenters, Mr. McRanie explains that ESP power input simply is not directly related to PM removal performance (particularly for the modern multi-section ESPs that are likely to be installed to comply with a proposed MACT standard), and the total amount of power is not nearly as important as the location at which the power is being applied in the ESP. The commenters refer to an attached report indicating that ESP parameters are likely to have no relationship to PM emissions at units that also have a wet scrubber, because wet scrubbers are highly effective in controlling high levels of PM from an ESP that is not performing at the intended control efficiency.

Comment 33: Commenter 17775 points out that many EGUs have discovered while seeking the high dust loads required under PS11 that even a fully disabled ESP may have little effect on resulting PM concentrations when a wet scrubber is operating at expected efficiency. Commenter 17775 concludes that EGUs should not be penalized for an ESP failure if another control, like a wet scrubber, is capturing the resulting PM.

Comment 34: Commenter 17800 states that when an ESP is used in combination with a wet scrubber the rule imposes operating limits on secondary power input to the ESP collection plates. (Section 63.10011(b)(6)(iii)). According to the commenter, the EPA's proposal is flawed. ESP power input simply is not directly related to PM removal performance, especially with a wet FGD following the ESP. According to the commenter, none of the ESP parameters are likely to have any relationship to PM at units that also have a wet scrubber, since those systems also are highly effective in controlling high levels of PM coming out of an ESP that is not performing at its intended control efficiency.

Comment 35: Commenters 17402 and 17808 use the example of normal ESP operation to explain why the proposed parametric constraints could lead to increases in emissions or damage to the control device. Commenter 17402 states that current, voltage, and total power are constantly reacting to boiler ash conditions, flue gas temperature, flue gas moisture, coal quality, coal moisture, flue gas flow rate, ESP cleanliness, ESP ash buildup, and fuel heat input. Commenter 17402 states that operating limits for control equipment based on a point-in-time stack test do not recognize the balancing act that plant operators perform daily to meet emission limits for not just HAP but all of the pollutants that are currently regulated.

Comment 36: Commenter 17808 agrees with the principle underlying the proposed parametric constraints on ESPs (i.e., that maximizing power input and electric field strength will generally maximize ESP collection efficiency), but the commenter states that plant operators need a degree of flexibility to balance the power input to the ESP in order to avoid serious damage to the system and downtime because the power input to an ESP is dynamically controlled by an automated voltage control system to maximize power levels while avoiding sustained arcing between electrodes and collecting plates, which can damage the ESP; automatic controls adjust power in response to various sensors so that normal power levels will vary depending on the amount of moisture in the air, accumulated ash levels, and other factors. Commenter 17808 advises that this core functionality of ESPs may make the proposed constraint for minimum voltage and current level inappropriate at certain times, and such a requirement could damage the control technology.

Comment 37: Commenters 17808 and 17725 recommend that the final rule require proper operation of the plant's pollution control equipment and appropriate parametric monitoring without establishing numeric operating limits.

Comment 38: Commenter 17772 notes that total secondary electric power is a poor measure of ESP performance. According to the commenter, this is especially true if it is tied to a minimum power concept. The commenter states that on some days particulate loading to an ESP can be low, yielding a lower number of fly ash particles to be charged. Moreover, according to the commenter, during periods of low loading, total power can go down to levels lower than that which may have been observed during the compliance test day if a larger number of fly ash particles were being sent to the ESP during the compliance test; voltage may still be high, but because current is lower; total power is lower, and that does not mean that the ESP is operating poorly relative to the compliance test levels. In such instances, according to the commenter, it is either not possible to maintain a high level of current or, if possible, it may be a waste of energy. Commenter 17772 believes that the requirement to maintain "the 12-hour average secondary power input at or above the operating limits established during the performance test" as required in section 63.10011 (c) is inappropriate and is not a true indicator of the operating condition of the ESP.

Comment 39: Commenter 17821 states that the secondary power approach for ESPs simply does not work and this fact is easily demonstrated by real world operating experience. According to the commenter, precipitator power will vary depending upon a number of factors, including operating conditions, coal quality, load, and other factors. According to the commenter, this is a phenomenon that the commenter routinely sees in the operation of its own units. The commenter states that precipitator operation is complicated even further with the addition of sorbents into the flue gas for emissions control and that different fuels may require more or less dry sorbent injection, and those fuels will also cause changes in precipitator operation. According to the commenter, these changes will likely result in a change in the total secondary power to the ESP but not necessarily a reduction in removal efficiency. The commenter states that the proposed rule should instead require site-specific plans to be developed for each EGU. According to the commenter, because ESP designs vary greatly, the parameters selected may include total percent of fields in service, or a limit on the number of fields in a given train that may be out of service at one time.

Comment 40: Commenter 17881 states that under Table 4 – Operating Limits for EGUs for ESPs, the requirement for ESPs conflicts with section 63.10011(b)(6)(iii), which does not impose a caveat on the ESP operating parameters such that it only applies to units with wet controls. The commenter further notes that the power input is calculated as the three-run average and not the lowest single run.

Comment 41: Commenter 17925 states that monitoring of total secondary power of the ESP should be optional if more representative parameters can be shown to be acceptable. According to the commenter, the EPA publication EPA-340/1-83-017 states that the efficiency of an ESP is directly related to the power delivered to the gas stream (watts/1000 acfm, page-171) and supports the notion that total secondary power of an ESP could be the monitoring parameter for ESPs. According to the commenter, however, using secondary power of each ESP operating field as the parameter, or total secondary power of the entire ESP, requires that combustion units maintain the same power level target parameter at lower fuel loads, which is difficult to accomplish. The commenter asserts that targeting of secondary power in each field is unnecessary for successful monitoring and compliance. The commenter recommends monitoring of total power to the ESP as a more practical parameter to work with than power to the individual fields if adjusted for changes to unit operating rate. To account for lower ESP power at lower operating fuel loads, the commenter suggests that the ratio of watts/1000 acfm should be monitored and targeted. According to the commenter, since the gas flow rate is generally proportional to the fuel firing rate, a surrogate for gas flow is fuel input rate. Therefore, according to the commenter, an alternate surrogate for total ESP secondary power when the fuel is, for example, coal, would be total secondary power divided by total coal input rate or watts/pound. According to the commenter, this total secondary power to fuel ratio parameter has been used in the past at combustion units to meet MACT requirements for ESP parameter monitoring and has been found to be acceptable both on a technical and regulatory basis. The commenter asserts that monitoring and setting the operational target for an ESP using this parameter ratio is superior to monitoring secondary power per field or even total secondary power to the entire ESP unit because it dampens the impact on the signal of unit operating rate.

Comment 42: Commenter states that difficulties can be encountered when attempting to set operating parameters entirely based on stack testing. According to the commenter, experienced equipment operators would not be willing to run equipment at potentially unsafe operating conditions that are not considered representative of normal operation, simply to provide set operating parameter ranges. The commenter also notes that while ESP power, a parameter that must be monitored as described in the EGU MACT rule, at minimum power, provides good ESP performance information, it is not necessarily a reliable indicator of poor performance. The commenter states that lower power generally means poorer performance, but ESPs are segmented into many electrical sections and the power consumption for each section relative to its physical location can mean that similar power consumption scenarios can provide different levels of emissions control. According to the commenter, this type of information would be difficult to verify through stack testing, considering other variables like fuel quality, varying loads, etc., but can be easily evaluated using an ESP performance model. The commenter notes that where CEMS are available that information should be used to evaluate excess emissions.

Comment 43: Commenters 17775 and 17790 recommend the use of boiler models or emissions models, in addition to manufacturer specifications, to set up acceptable operating ranges. The commenter notes that, for example, in the CAM Program, the use of models and manufacturers information is allowed and that in the guidance document "Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic

Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-fired Boiler", use of ESP models is recommended, and the commenter refers to page 5 of this document: "An approach that has been demonstrated to provide a reliable indication of ESP performance is the use of an ESP performance computer model calibrated using site-specific data and other data in conjunction with continuous opacity data." Commenter 17775 states that the EPA should include in this rule an option similar to subpart Da to use an ESP model on a daily basis to assess proper operation of an ESP in between performance tests. According to the commenter, if the use of the model as required under subpart Da is sufficient to assure compliance with the NSPS, it also should be sufficient under subpart UUUUU.

Response to Comments 31 - 43: Although the EPA notes some owners and operators have been successful in using parameters to model ESP performance, the comments are inapplicable, for the rule no longer requires parameter monitoring or operating limits for PM control devices.

6. Parametric limits for wet scrubbers (section 63.20011(b)(6)).

Comment 44: Commenter 17775 expresses concerns with the proposed parametric operating limits for wet scrubbers at section 63.20011(b)(6)(i) and (ii); the commenter states that the proposed parametric ranges established during performance tests lack a sufficient relationship with actual emissions over normal operating ranges. The commenter references an attached report indicating that the normal pH in a scrubber can vary significantly, but that as long as pH is within the normal range, its impact on scrubber efficiency is minor. According to the commenter, however, if pH falls too low, metal components can corrode, and if pH is too high, calcium sulfate deposits can develop. The commenter states that as a result, operators monitor pH to ensure it is within the desired range and react to bring pH back within that range if necessary. According to the commenter, operators have no incentive to allow pH to fall outside the normal range. Commenter 17775 concludes that requiring operators to artificially maintain pH to the level during a performance test is not a useful requirement.

Comment 45: Commenter 17821 states that pH measurement is not sufficiently related to acid gas removal to apply enforceable limits. According to the commenter, the measurement of pH in an FGD system is only a small part of the very complex chemistry in an SO_2 removal system; the pH is mainly used to prevent scaling of the modules. The commenter asserts that maintaining a higher pH does not guarantee any additional removal of SO_2, HCl, or other acid gases, but that higher pH values will lead to scaling, which may lead to other operational problems. The commenter states that as an example, scaling can cause plugging of mist eliminators, which in turn could potentially increase particulate emissions. The commenter notes acid gases such as HCl and HF are strong acids and very readily dissolve in water, whereas SO_2 is a weak acid, which explains why its transport from the gas phase into the liquid phase in a scrubber occurs at a slower rate. According to the commenter, the EPA acknowledges that acid gases are likely to be removed in typical FGD systems due to their solubility or their acidity (or both). The commenter states that the conclusion is that HCl and other acid gases are very effectively removed by contact with water in a wet FGD system, so effectively removed in fact, that high removal rates will be maintained even at pH levels below those used for effective SO_2 removal, provided there is an adequate recirculation flow. Instead of requiring FGDs to maintain a specified pH, the commenter suggests that the rule should require that sites develop site specific plans that incorporate parameters that more appropriately describe the operation of an FGD system. For example, the commenter suggests that stations may elect to use parameters such as number of absorber recirculation pumps in service, measured SO_2 levels from CEMS measurements, or other facility specific measurements.

Comment 46: Commenter 17821 states that there is ambiguity in what the EPA wants to restrict. There are two potential liquid flows in an FGD system; the first is the amount of chemical reagent that is added to the FGD module. According to the commenter, this is most commonly either a water slurry of lime or limestone, the concentration of this material varies depending upon the operating condition, and the mass flow rate of reagent is directly proportional to the mass of SO_2 that is removed in the scrubber per unit of time. According to the commenter, because the chemical reagent must be added at the proper stoichiometric ratio, it is totally inappropriate to require a fixed feed ratio based on full load, worst-case conditions; doing so will damage the FGD system and will render it ineffective for removing SO_2 and other acid gases. As a result, the commenter concludes, the EPA is not attempting to regulate lime or limestone reagent flow but instead seeks to regulate the total amount of liquid flow that is recirculated in the module and sprayed into the flue gas stream. The commenter states that FGD modules use one or more recirculation pumps to remove large volumes of FGD liquor from a reservoir in the bottom of the module and spray it into the flue gas; these are high volume, centrifugal pumps that run at a single speed. According to the commenter, most sources do not normally install flow meters in this situation, and installing monitors in this application will not achieve the accuracy that the EPA specifies. The commenter states that most new FGD installations utilize fiberglass reinforced piping (FRP) to transport recirculation flow through the FGD module. According to the commenter, the FRP increases reliability but is not conducive to external flow measurement techniques, and further complicating the matter is size of the piping—the larger the diameter, the more difficult to obtain accurate readings. According to the commenter, flow meters with the proposed accuracy of 2 percent are not practical for these FGD installations. The commenter states that internal flow meters may be able to provide more accurate readings immediately after installation, but the harsh conditions of the FGD will cause them to lose accuracy quickly. In any event, according to the commenter, the length of FGD piping is short compared to its diameter, and has many elbows and fittings, so it typically does not have enough straight lengths of pipe to allow for the installation of highly accurate flow monitors. According to the commenter, even if the recirculation flow rate could be measured to the desired accuracy, those measurements would not tell the whole story. The commenter states that in a properly operating FGD system, the density of the recirculation flow has to change with different operating conditions to maximize removal efficiency and that when the density of a material being pumped increases, the volume of flow through a centrifugal pump decreases. According to the commenter, FGD operators do not have control over this recirculation flow because the piping systems do not have any sort of flow control valves. In short, the commenter states, a recirculation pump is either on or off, and . therefore attempting to maintain volumetric flow rates at a level established during the performance test will cause operators to chase process parameters that would be counterproductive to achieving the best removal efficiency.

The commenter states that the EPA should also realize that when an EGU reduces its load, the volume of flue gas passing through the FGD system decreases, but the amount of recirculation flow stays relatively constant. According to the commenter, this results in an increase in the liquid to gas ratio, which in turn promotes even more efficient scrubbing. Therefore, the commenter states, the more appropriate metric would be to require that EGUs be required to maintain a minimum recirculation flow to gas ratio instead of a simple minimum liquid flow rate. According to the commenter, that would best be accomplished by requiring a minimum number of pumps to be kept in service at all times as demonstrated during the performance test, and as a result, flow monitors would not be needed or installed. In addition, the commenter states, it would be appropriate for the EPA to require sources to demonstrate that the flue gas is indeed going through the scrubber module and is not being bypassed. According to the commenter, these parameters will adequately ensure that the FGD operation will properly remove the acid gases that will be regulated in the final rule.

Comment 47: Commenter 17821 states that restricting FGD modules to minimum pressure drop requirements has no benefit. According to the commenter, in the proposed rule, stations would be required to measure differential pressure across the FGD module(s) during the annual performance tests, and maintain a 12-hour pressure drop value above the average measured in the performance test. The commenter asserts that like other limits the EPA has proposed, this limit fails to account for reduced load operation. According to the commenter, FGD pressure drop is a direct function of the amount of flue gas flow through the module, and thus is directly related to boiler load. In a case where velocity doubles, the commenter stats, the pressure drop would quadruple. The commenter asserts that the reverse is also true, in that as the load drops, the scrubber pressure drop would also decrease. According to the commenter, there are different types of FGD systems such as open spray towers, and units with trays; however for all these designs, a reduced pressure drop at lower load does not by itself indicate a reduced level of HAP capture in a FGD system. In fact, according to the commenter, the scrubber performance is more likely to improve at reduced load because there is a higher ratio of liquid flow to flue gas flow; pressure drop is more a function of mist eliminator cleanliness than acid gas removal. The commenter notes that there may be steady state systems, such as waste combustors, where measuring pressure drop could be useful. The commenter asserts that instead of using pressure drop to demonstrate compliance, the EPA should require sources to develop site-specific plans to ensure the effectiveness of the FGD for particulate removal and acid gas removal, which would then be subject to review by state and local agencies and contain more appropriate requirements such as maintaining a minimum number of recirculation pumps in service, eliminating any bypasses of the FGD system, and periodically inspecting internal components.

Comment 48: Commenter 18428 states the EPA's proposal to use pH, pressure drop and liquid flow-rate as operating parameters for wet scrubbers is subject to the same flaws as the EPA's other proposed operating limits -- namely the lack of a sufficient relationship between the parameters measured during performance testing and actual emissions. For example, the commenter states, because scrubber pressure drop, liquid flow rate, and sorbent injection rate vary with boiler load, establishment of a limit based on conditions during performance testing may tell the EPA little about actual emissions under other load conditions.

Comment 49: Several commenters (17775, 17868, 17800) state that because scrubber pressure drop, liquid flow rate, and sorbent injection rate vary with boiler load, establishment of a limit based on conditions during performance testing may tell little about actual emissions under other load conditions. Moreover, according to the commenters, when the EPA in 2008 considered the relationship between liquid flow rate and PM in the context of the NSPS for electric steam generating units at 40 CFR subpart Da, the EPA concluded that, at the level of the NSPS (i.e., 0.015 lb/MMBtu), PM emissions controlled by an ESP were not particularly sensitive to the actual liquid flow rate (U. S. The EPA "Response to Public Comments on Rule Amendments Proposed June 12, 2008 (73 FR 33642)" (Nov. 2008), U.S. EPA-HQ-OAR-2005-0031-0284, at section 2.5.3).

Comment 50: Multiple commenters (17736, 17715, 17627, 17757, 18037, 18539, 19114) state that the proposed rule lays out a method to establish site specific operating limits for various types of control equipment in Tables 7 and 8. According to the commenters, for example, a wet scrubber would be required to meet site-specific operating limits for pressure drop and liquid flow rate for compliance with the PM standard. The commenters note that pressure drop and liquid flow rate may not be applicable to all types of wet scrubbers and that the parameters may not be directly related to emissions. According to the commenter, pressure drop is not a direct measurement of emissions and will naturally vary with load. The commenters also suggest that liquid flow rate is also a function of load and the ability to measure it accurately may be a problem. According to the commenter, the same issues are encountered when using these parameters as a metric for demonstrating continuous compliance with the HCl limits.

Comment 51: Commenters 17775 and 17881 state operating limits are not direct measurements of emissions or compliance. The commenters state that the proposed rule includes a requirement for wet scrubber controls to maintain a pressure drop across the scrubber and a minimum liquid flow rate. The commenters note that pressure drop is not used for control purposes, it is used to determine when cleaning is required and is not necessarily accurate for assessing scrubber performance. Commenter 17775 states that the EPA must also recognize that Chiyoda scrubbers operate on a completely different set of parameters than typical spray towers and that L/G is a more useful indicator for some types of scrubbers. Commenter 17881 notes that under Table 4 – Operating Limits for EGUs for wet acid gas scrubbers the requirement states to maintain a minimum pH. Controlling pH is a maintenance incentive to prevent corrosion to major scrubber components. According to the commenter, the pH of the scrubber vessel is an indication of the limestone slurry feed into the vessel, not the effectiveness of the slurry spray.

Comment 52: Commenter 18023 states that pressure drop and liquid flow rate are not indicators of the level of PM control being achieved by a wet scrubber. According to the commenter, the establishment of operating limits for pressure drop and liquid flow rate would unnecessarily limit the range of key FGD operating parameters. According to the commenter, pressure drop is not a universal indicator of the PM control achieved by wet scrubbers (Commenter refers to Figure 26 in its comment). According to the commenter, PM control by a modern jet-sparging type scrubber is not a function of pressure drop (three figures are provided in the document showing PM control vs. pressure drop, liquid flow rate and liquid-to-gas ratio). The commenter further notes that liquid flow rate is not a universal indicator of the PM control achieved by wet scrubbers. In the commenter's experience, PM removal by a modern spray-tower-type scrubber varies widely for different liquid flow rates. According to the commenter, PM control is also not a function of liquid-to-gas flow rate.

With respect to HCl scrubbing, the commenter states that HCl is not easily monitored on a continuous basis in flue gas. According to the commenter, pressure drop, liquid flow rate, and pH are not indicators of the level of HCl control being achieved by a wet scrubber, and the establishment of these operating limits would unnecessarily limit the range of key FGD operating parameters. The commenter states that HCl control by modern jet-sparging type scrubbers is not a function of liquid submergence (or its corollary pressure drop). Liquid submergence effectively changes the liquid-to-gas ratio of a scrubber. The lack of correlation between HCl emissions and liquid submergence suggests that there is also no correlation between HCl emissions and liquid flow rate.

Response to Comments 44 - 52: The comments are moot, as the rule no longer includes specific requirements for parametric monitoring or operational limits for acid gas control devices.

7. Operating limits for low-emitting EGUs (LEEs).

Comment 53: Commenter 17402 states that operating limits are particularly inappropriate for low emitting units because the commenter believes the operating limit procedures in the proposed rule are repetitive, are counter to the purpose of the rule, and can result in facilities being deemed non-compliant when controls are operating properly. The commenter states that these concerns are even more applicable to LEEs, as the emissions associated with LEEs are dramatically lower than those of the rest of the fleet. The commenter is concerned that slight variations in operating limits that deviate from the operating conditions of the most recent performance test (that indicated the unit operates normally at a fraction of the standard) may be deemed non-compliant and cause the unit to lose LEE status when in reality the emissions never approached the MACT emissions limit. According to the commenter, this result is not consistent with the impact of minor variations in operating limits, and the EPA should remove all operating limits from the rule, and in particular from application to LEEs, where such standards are especially inappropriate.

Comment 54: Commenter 18426 states that the proposed rule includes a LEE definition for compliance monitoring purposes. According to the commenter, for Hg, emissions less than 10 percent of the Hg emissions limitation or less than 22.0 pounds per year on an existing unit may qualify for LEE status for Hg. The commenter notes that for Michigan's Hg rules, a cut-off of 9 pounds per year, per unit was developed as protective through the rulemaking process. According to the commenter, this could be a smaller utility unit (25 MW to 100 MW) or a larger unit with low utilization where installing a Hg CEMS is not feasible due to low emissions or economical due the unit utilization.

Comment 55: Commenter 17752 requests clarification on the criteria for qualifying for LEE with regard to references to operating parameter limits in proposed section 63.10005(k)(3) and section 63.10006(c). The commenter requests that the EPA clarify whether the use of ACI is permissible to qualify for LEE and how operating limits would apply in that circumstance. The commenter also requests clarification on fuel sampling as an operating limit and as a demonstration of compliance; it is not clear to the commenter if the proposed rule intends for LEEs to comply with maximum fuel input levels under section 63.10011(b) and the compliance provisions in section 63.10011(c).

Comment 56: Commenters 17775 and 17868 support the LEE option but find that the proposed LEE requirements for "operating parameter limits" are not clear. Commenter 17775 finds the following inconsistencies with respect to Hg testing periods that need to be addressed in the final rule:

1. Commenters 17775 and 17868 state that the EPA should remove or appropriately clarify the references to operating limits for LEEs. According to the commenter, proposed section 63.10005(k)(3) and section 63.10006(c) refer to establishment and maintenance of "operating limits," but the provision cited in section 63.10005(k)(3) for establishing such limits – section 63.10010(k)(3) - does not exist and no other provisions address operating limits for LEEs. According to the commenter, proposed section 63.10021(a)(17) states that, for LEEs, results of emissions tests and fuel analysis - presumably the monthly fuel analysis required under section 63.10006(c) - demonstrate continuous compliance, and the provision does not mention operating limits.

2. According to the commenters, the EPA's descriptions of the requirements for LEEs suggest they are not required to establish or comply with operating limits. Specifically, the commenters say that the EPA states: For existing units that qualify as low emitting EGUs (LEEs), conduct subsequent performance tests for the LEE qualified pollutants every 5 years and perform fuel analysis monthly. Commenter 17775 states that if the EPA intended to require that LEEs perform monthly fuel analysis under section 63.10006(c), the EPA needs to make clear that compliance with the maximum fuel input levels is not required and explain why it chose monthly testing. The commenter believes that analyzing fuel monthly when the fuel supply or mixture has not changed seems unnecessary.

3. Commenter 17775 states that if the EPA intended to require that LEEs establish and comply with maximum fuel input levels as an "operating limit" under section 63.10011(b), rather than perform monthly fuel analysis, the EPA needs to explain that the fuel analysis is an operating limit and not a demonstration of compliance using fuel analysis under section 63.10011.

4. Commenter 17775 also states that the EPA needs to remove the monthly fuel sampling and analysis requirement in section 63.10006(c). According to the commenter, if the EPA intended to require that

LEEs establish and comply with operating limits other than maximum fuel input levels, the EPA needs to issue a proposal that explains the purpose of those limits and how they apply.

Comment 57: Several commenters (19536, 19537, 19538) states that the EPA should discard its "Low Emitting Units" monitoring protocols. According to the commenter, monthly fuel testing does not assure continuous compliance, and the EPA's variability analysis indicates HAP emissions are variable. Monthly testing does not reveal any information about emissions between the monthly tests. According to the commenters, the LEE monitoring should be expanded to require operational parameter monitoring as required for all other compliance testing, and monthly fuel sampling further excludes emissions during startup and shutdown. The commenters state that the LEE exemption should be eliminated, or the threshold redefined to capture only those plants whose future emissions are assured to remain below the prescribed limits. According to the commenters, if the EPA were to provide reduced monitoring for certain low-emitting units, it should use a UPL for its thresholds, and if data from a unit indicates that the 99% UPL of that unit's emissions are below 10% of the MACT limit, the EPA can be reasonably assured that unit's future emissions will be below that threshold.

Response to Comments 53 - 57: The comments are inapplicable because the rule no longer requires operating limits for LEEs.

8. Oil-fired operating parameter comments.

Comment 58: Commenter 18025 states that for oil-fired EGUs the commenter recommends an alternative approach that will better ensure proper operation of pollution control systems. Rather than establishing fixed operating limits, the commenter recommends that the EPA require proper operation of the plant's pollution control equipment and appropriate parametric monitoring without establishing numeric operating limits.

Comment 59: Commenter 18428 states that it is not clear whether operating parameters and fuel input limits in proposed section 63.10011(b) to apply to oil-fired units. According to the commenter, the preamble statement suggests that operating parameters do not apply ("Except for liquid oil-fired units,...we are proposing that you monitor during initial performance testing specified operating parameters"). The commenter states that similar to LEEs, however, the EPA also suggests that liquid oil-fired units must meet maximum fuel input limits as an operating limit. The commenter recommends that the EPA should make clear in section 63.10011(b) what operating limits apply as well as explain why.

Response to Comments 58 - 59: The final rule clarifies that operating limits do not apply to these units, with the exception of where: (1) a source elects to use a PM CPMS and an associated operating limit as a means to ensure continuous compliance with an underlying filterable PM standard or non-Hg HAP metals standard (or all HAP metals standard for liquid oil-fired EGUs); or, (2) a liquid oil-fired unit uses quarterly testing to demonstrate compliance with acid gas emission limits (in which case the source must develop a site-specific monitoring plan). See the final preamble for further discussion. Note that liquid oil-fired sources may also use fuel moisture content analysis or supplier certification to show compliance with the acid gas standards.

9. Minimum sorbent injection rates.

Comment 60: Commenter 17821 states that there are multiple problems with the sorbent injection rate requirements. DSI and ACI feed rates are normally correlated with other plant conditions, such as unit load or flue gas flow, making a single fixed feed rate inappropriate. As an example, sorbent rates are normally set as a mass flow per volume of flue gas, such as a pound of sorbent per hundred thousand cubic feet of flue gas. As a result, half the amount of sorbent would be injected when the flue gas flow is reduced to half the flow rate. Interestingly enough, the same mass feed rate of sorbent may actually be more effective at low flue gas flow rates, because it has more time to react due to the lower velocity. However it will also increase the amount of byproduct material generated. Commenter states that the problem of using one minimum flow rate for all conditions is the measurement of a sorbent has problems. The material handling equipment for a dry solid such as Trona, ACI or other materials whether milled or not, is not capable of precise weight measurements. Load cells are typically used to gather injection rates, but because the material can clump or surge, short term measurements such as a 15-minute interval are too small to absorb all these fluctuations. Finally, DSI is also closely linked with ESP performance. Injecting a "minimum" amount of sorbent over the entire operating range of a unit could change the ash resistivity and thus impact precipitator performance, potentially making it impossible to be in compliance with the operating limits for both sorbent injection rate and ESP total secondary electric power. The commenter recommends that the EPA should allow sources to develop site-specific correlations between sorbent injection rates and an appropriate to source parameter such a flue gas flow or unit load. These rates would then be monitored over a longer time average such as 6-12 hours. In cases where CEMS are used to demonstrate compliance with HCl or Hg standards, limits on sorbent inject rates should not be required since the CEMS would be used to demonstrate compliance.

Comment 61: Several commenters (17622, 18037 and 18023) refer to the proposed compliance approach for DSI systems (i.e., setting operational limits of reagent injection rate based on performance testing at 76 FR 25031 and 25129). Commenter 17622 states that if operational limits consisting of injection rates for DSI technology are going to be utilized to demonstrate compliance for a given level of HCl control, the reagent reactivity must also be considered an operational limitation. The commenters advises that for $Ca(OH)_2$, this could be accomplished by including reagent physical parameters such as porosity and surface area in the operational limitation. Commenter 17622 also advises that for sodium reagents, the physical properties of either Trona or sodium bicarbonate can impact the effectiveness of a specific reagent for an acid gas control application; as an example, the particle size to which Trona is milled prior to use is an important consideration. Commenters 18023 and 18037 state that the minimum sorbent injection rate may be an appropriate operating limit for DSI and/or carbon injection; however, the operating limit should be established in a way that accommodates operating over a wide load range because it would not be prudent (i.e., it would pass unnecessary costs on to electricity customers) to operate a sorbent injection system at the maximum injection rate when running at reduced load. Commenter 18023 concludes that the operating limit should allow normalizing for gas flow such as lb/MMacf or a calculated ratio. The commenter also states that dry scrubbers should have the option to maintain the SO_2 removal rate at or above the lowest 1-hour average rate during the most recent performance test because this is more consistent with how dry scrubbers are operated in the industry. Commenter 18023 concludes that any minimum sorbent injection requirement for DSI, carbon injection and dry scrubbers should be set in a manner that allows for efficient use of sorbents across all operating load ranges because minimizing sorbent injection is an important consideration both environmentally and economically and injecting sorbent in excess of what is necessary (simply to meet an arbitrary limit set by an emission test at one point in time) creates an additional potential waste stream that must be managed. Commenter 18037 states that setting a minimum injection rate will potentially hurt units as they attempt to balance their PM limit with the minimum injection of sorbent necessary to control Hg or HCI. According to the commenter, sources should be able to maintain the flexibility necessary to meet all of their emissions obligations.

Comment 62: Commenters 17775 and 17800 state that the EPA should consider and review data to evaluate use of a load factor adjustment for those operating parameters that are load dependent. The commenters state that the EPA finalized a load factor adjustment in the Industrial Boiler MACT for sorbent and carbon injection; specifically, the EPA revised the definitions of "Minimum sorbent injection rate" and "Minimum activated carbon injection rate" to take load into account by multiplying the "lowest hourly average" by a new term called the "load fraction" (see section 63.7575).

Comment 63: Several commenters (17627, 17715, 18539, 19114) take exception to the use of the minimum sorbent injection rate parameter for dry scrubbers or DSI in Table 4 because they assert that such a restriction removes all of the flexibility that a unit has to meet all of its obligations, and sorbent quality may vary between suppliers requiring different injection rates per product. Additionally, they assert, sorbent may be injected for reasons other than for HAP control; for example, during the periodic MACT performance test an injection rate may be set based on temporary atmospheric conditions requiring more injection for SO_3 control; however proposed Table 4 would require the injection rate based on SO_3 conditions must be utilized until the next performance test for HAP compliance, despite the fact that the injection rate was not related to HAP control.

Comment 64: Commenter 17805 states that according to the proposed rule requirements, ACI amounts, or other control media, would be set at the highest operating load and a unit would not be able to reduce the amount of product injected when running at lower loads and corresponding lower flue gas flows. According to the commenter, this does not make economic sense and is wasteful to add more material than necessary to control emissions.

Comment 65: Commenter 17881 states that Table 4 – Operating Limits for EGUs, the DSI sorbents are likely targeting HCl/HF, not just Hg as suggested in this requirement. According to the commenter, this paragraph should recognize that there may be multiple pollutant specific sorbents.

Response to Comments 60 - 65: These comments are inapplicable because the rule no longer requires operating limits for sorbent injection.

10. PM CEMS operating limits (section 63.10011(d) and table 4, parameter 8).

Comment 66: Several commenters (17705, 17754, 17775) request that the EPA clarify how the PM operating limits must be established because the provisions of proposed section 63.10011(d) are inconsistent with the provisions for PM CEMS in proposed Table 4. Commenter 17775 adds that the EPA has provided no data or discussion to explain how the average of three Method 5 runs would be sufficient to capture variability under a various normal operating conditions. Commenter 17775 takes exception to the use of the term "highest hour" in proposed Table 4 item 8 because it is not clear to the commenter whether this term applies to Method 5 data or CEMS data. The commenter believes that item 8 makes no sense relative to Method 5 data, since runs are not measured in hours but in sample volume (and runs will be more than one hour). The commenter also believes that item 8 makes no sense relative to hourly PM CEMS data because at the time the operating limit is established because the values would simply be output from the uncorrelated CEMS.

Response to Comment 66: In consideration of the PM emissions limit and the potential burdens associated with certifying a PM CEMS via PS 11, the agency decided to focus on the use of a PM instrument not as a CEMS but as a CPMS. The PM operating limit for use in conjunction with a PM CPMS functions in the same manner as parameter monitoring from other rules. The highest hourly average of the PM CPMS signal produced over three test runs is used as the operating limit, and that value becomes averaged over a rolling 30 boiler operating day average. The "highest hour" in Table 4 is correct and refers to the Method 5 run data. Section 63.10011(d) is revised to be consistent with this approach. The final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

11. CPMS averaging times.

Comment 67: Commenter 17775 states that the EPA should clarify the averaging time of the required parametric monitoring. According to the commenter, although the EPA proposes to define the minimum operating parameters in section 63.10042 in terms of "90 percent" of the "test average" during the most recent performance test, and to require compliance on a 12-hour average basis under Table 8, other provisions and statements contradict that definition. For example, states the commenter, proposed Table 4 instructs sources to maintain parameters "at or above the lowest 1-hour average" during the most recent performance test; proposed section 63.10021(c) requires determination of a "3-hour rolling average of the CPMS data collected"; proposed section 63.10022(a) requires units using emissions averaging to maintain the "3- hour average parameter values" for various control devices at or below the operating limits established during the most recent performance test; and in the preamble, the EPA describes operating limits as "[t]he average of the three minimum (or maximum) values from the three runs for each applicable parameter . . . ." 75 FR 25,029/3. The commenter assumes that the proposed definitions and the 12-hour average in Table 8 reflect the EPA's intent. The commenter asserts that the EPA also must provide data to support achievability and enforceability of operating parameters under its proposed definitions. The commenter states that although the EPA does not explain the "90 percent" criterion in this rule, when the EPA previously promulgated a similar definition in the 2004 IB MACT, the EPA explained that 90 percent value was intended to provide a range around the test average to account for normal variations in the operation of the source and the control device (EPA Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (Feb. 25, 2004), EPA-HQ-OAR-2002-0058-0611 at 54). According to the commenter, the EPA must provide data to confirm that the 10 percent allowed variance is sufficient. The commenter states that before finalizing a rule that imposes parameters as enforceable limits, the EPA must analyze data to determine what definition provides adequate flexibility.

Response to Comment 67: The rule retains two operating limits in the final rule: for a PM CPMS and for site-specific parameters from liquid-oil fired EGUs that choose to comply with quarterly emissions testing for acid gases. See the final preamble for further discussion. The rule plainly states the PM CPMS operating limit averaging period as each rolling 30-day operating period. The limit is set based on the highest 1-hour average monitor output signal during a successful performance test. That average serves as a measure of ongoing control of the unit in accordance with the operations that exist during the performance test, and is similar to how the Agency has established operating limits under a number of NESHAP standards. The appropriate parameter, monitoring approach, and data reduction requirements (including averaging periods as appropriate) for the liquid oil-fired units will be set forth in the source's monitoring plan. See the final preamble for further discussion.

12. Optional moisture measurement technique.

Comment 68: Commenter 17715 proposes an additional option be available for measuring moisture: if the stack is saturated, a source should be able to use temperature, absolute pressure, and a psychrometric chart to determine moisture; temperature and pressure transmitters can be calibrated with NIST traceable equipment; during periods when the stack is not saturated, default factors listed in the rule could be used.

Response to Comment 68: While the rule does not contain the additional options mentioned by the commenter, the commenter remains able to request use of such instrumentation via the general provisions at section 63.8(f) of subpart A of part 63.

13. Frequency of QA/QC requirements for parametric monitoring devices.

Comment 69: Several commenters (17716, 17725, 18014, 18498) state that sources that are required to conduct control device parameter monitoring must follow prescriptive QA/QC requirements and performance evaluation schedules as outlined in section 63.1 0010. According to the commenters, some of these requirements are unnecessarily frequent, such as the need to check pressure taps at least once each boiler operating day, and the requirement to conduct annual evaluations of ESP power monitoring systems is excessive particularly for large ESPs with numerous electrical bus sections. The commenters suggest that the EPA specify all operating parameter QA/QC activities and performance evaluations in accordance with manufacturer's recommended procedures.

Response to Comment 69: In the final rule, the source owner or operator must prepare a site-specific monitoring plan for its PM CPMS, and, for those liquid oil-fired sources that choose to conduct quarterly acid gas emissions testing, for appropriate parameters to demonstrate that operations at the unit remain consistent with operations during the performance test. See the final preamble for further discussion. This plan identifies the QA/QC procedures the source will follow and calls generally for a daily performance evaluation of some form for most monitoring devices as a basic QC check. No specific QC checks have been prescribed in the rule; rather, the source owner or operator is able to choose the specific method that will be used to fulfill this QC check in conjunction with developing the site's monitoring plan.

14. Consistency of rule with data gathered during the 2010 ICR.

Comment 70: Commenter 17775 believes that the EPA cannot require stack testing under conditions it did not consider in the standard setting process. Neither does commenter 17775 believe that the EPA can require EGUs to operate at a fixed load for 30 operating days. According to the commenter, the EPA proposes to require that all "performance testing" be conducted at "maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content of chlorine, fluorine, non-Hg HAP metals, and Hg" (Proposed section 63.10007. The commenter states that the EPA also proposes that it be able to request that performance tests be conducted under other representative conditions, and that EGUs be required to provide records to determine those conditions upon request (proposed section 63.10007(f)). The commenter states that for EGUs using CEMS, the "performance test" runs for 30 operating days (proposed section 63.10005(a)). The commenter states that for these EGUs, the EPA must recognize that it may not be possible to maintain "maximum" normal operating load for a full 30 operating days. According to the commenter, instead, the EPA should simply require representative operation. The commenter states that because such sources are monitoring compliance continuously after that point, there is no reason to require worst case testing conditions.

Response to Comment 70: The agency maintains that it has adequately incorporated variability into the final standards in response to other comments on this issue.

15. Frequency of stack tests.

Comment 71: Commenter 17736 states that bi-monthly stack testing imposes an unnecessary drain of resources and will, inevitably, force units into non-compliance. The commenter states that an EGU electing to comply with the total or individual non-mercury HAP metal emissions limit (without CEMS) is required to demonstrate continuing compliance by stack testing every two months and that stack testing at such a high frequency is an unnecessary drain of resources. According to the commenter, conducting six stack tests in one year is a grossly expensive, time consuming, and disruptive requirement. The commenter maintains that the proscribed parameter limits should be eliminated and replaced with provisions allowing facilities to work with states to develop site-specific compliance plans, if deemed necessary, bi-monthly stack testing is especially excessive if/when the unit is subject to any additional monitoring requirements.

Comment 72: Commenter 17775 states that proposed fuel input limits and frequent periodic stack testing requirements are duplicative because under the proposed rule, the maximum time between stack testing for non-Hg metals and HCl (for units using stack testing to demonstrate compliance) is approximately 60 days (i.e., every other month for EGUs with PM controls). The commenter states that if an EGU plans to combust a new fuel type or mixture and that fuel exceeds the maximum metals input level during the prior performance test, a new performance test is required within 60 days of combusting that fuel (proposed section 63.10021(a)(4), (6), and (8)). According to the commenter, because testing already is required every 60 days, the requirement to test following a revised maximum fuel input limit is duplicative. However, the commenter states, given the notice and planning requirements for stack tests, it also is not reasonable to require stack testing sooner. According to the commenter, current operating parameters provide a reasonable assurance of compliance prior to the any new performance test and requiring testing of new fuels, and stack testing in response to changes in maximum fuel input, are more than sufficient to addresses any concern that a change in fuel warrants reexamination of those operating parameters. The commenter contends that the EPA has not provided adequate justification for such frequent stack testing, and therefore the final rule should require stack testing no more frequently than annually unless such a test is triggered by a change in the maximum fuel input as a result of a change in fuel type.

Comment 73: Commenter 17798 recommends, for PM, stack testing every 2 years or at a maximum on an annual basis in conjunction with monitoring operating parameters. According to the commenter, for units without pollution control equipment the source should perform continuous monitoring or stack testing every 6 months. The commenter further recommends that the stack testing regime address determining minimum and maximum operating parameters of control equipment under different conditions to address variability. According to the commenter, for pollutants with emission limitations (acid gases and Hg) the EPA should apply the same structure for CEMS and stack testing as discussed here for PM requirements. The commenter states that also for these pollutants, testing and setting of pollution control operating parameters should be applied only in conjunction with the stack test compliance demonstration option. According to the commenter, these changes will streamline the process, reduce cost, and achieve the same environmental result.

Comment 74: Commenter 17902 states that testing should be allowed on a less frequent 3-year or 5-year basis when HAP emissions are significantly below the MACT emissions limits (as the EPA has proposed in section 63.1 0006). The commenter states that additionally, EGUs that participate in an emissions averaging plan should not be restricted from reduced performance testing if the relevant HAP emissions from the units in combination are in fact below the percent thresholds of the relevant MACT limits.

Comment 75: Commenter 18426 states that emissions testing required monthly or every other month depending on the unit and pollutant specified in the proposed rule is excessive and inconsistent. According to the commenter, if an acceptable parametric monitoring system is developed, emissions testing once a year or every other year should be sufficient, and even if no emission control system is in place, unless a significant change in the fuel characteristics occurs, emissions testing once a year or every other year should also be sufficient. The commenter recommends that at a minimum, the EPA should make the testing and monitoring requirements consistent for the units and pollutants.

Response to Comments 71 - 75: The agency agrees that fuel input and frequent periodic stack testing requirements could be duplicative; therefore, the rule no longer requires fuel analysis for pollutants. The rule requires quarterly emissions testing for units that choose to use emissions testing. In addition, sources remain subject to underlying parameter monitoring that applies to many of these units, through Compliance Assurance Monitoring (40 CFR Part 64) or other existing regulatory programs. For liquid oil-fired units that choose to use emissions testing, there is an additional requirement for continuous parameter monitoring of the method of control for acid gases. See the final preamble for further discussion. The quarterly stack testing period, coupled with underlying monitoring of control devices or the additional monitoring for liquid oil-fired units, is expected to be frequent enough to ensure that a unit's emissions control devices and processes continue to operate in the same manner as during the previous stack test. If there are significant changes to the operation of the unit or the fuel, then a retest is required to reconfirm that the source remains in compliance under the new operating circumstances.

16. Operating parameters during SSM.

Comment 76: Commenter 17886 states that during startup, shutdowns, and malfunction periods use of established parameters set during performance tests would not be proper. The commenter notes that the EPA has not addressed this concern in the proposal but should consider some best management practice option during those periods.

Comment 77: Several commenters (17775, 18428, 17800) state that they are very concerned about the potential for enforcement of operating parameter and opacity limits during periods of startup, shutdown, and in the event of equipment malfunction. According to the commenters, the current proposal would allow enforcement of deviations from operating parameter limits during periods of startup and shutdown, when controls would not be expected to be operating at the same levels as during performance tests. The commenters note that the EPA did assert in the preamble that SSM conditions were taken into account by proposing use of 30 boiler operating day rolling averages and by the fact that EGUs often use cleaner fuel during startup. According to the commenters, these assertions regarding startup and shutdown are inapplicable to control device operating parameter limits, which are based on 12-hour averages established during performance testing. In short, assert the commenters, the EPA has made no allowance in its operating limits for periods of startup and shutdown but to the contrary, the EPA has proposed to require sources to establish control device operating parameter levels that are dependent upon load during periods of "maximum normal operating load," or other frequently used loads, and then maintain those levels during other periods, including startup and shutdown. The commenters urge the EPA to address these periods in another manner, for example by establishing simple work practice standards in lieu of operating parameters.

Response to Comments 76 and 77: As mentioned elsewhere, the final rule no longer requires continuous measurement of operating parameters, except when PM CPMS are used and when a liquid oil-fired EGU without an FGD uses a combination of emissions testing and continuous operating parameter monitoring to demonstrate compliance. Because work practice standards apply during periods of startup and shutdown, the EPA has clarified in the final rule that the PM CPMS operating limit does not apply during such periods. Instead, for coal and other solid fuels, the work practice standards for such periods will apply, together with the monitoring and recordkeeping required to document compliance with those work practices. The final rule also provides for sources to apply affirmative defense of excess emissions including deviations from PM CPMS measured operating limits relative to process malfunctions.

17. Operating limits based on total PM.

Comment 78: Commenter 17402 states that they support operating limits based on total PM and not filterable PM. The commenter believes total PM is a more complete, more flexible, and better protective standard. The commenter asserts that that there is too much variability with PM CEMS technology for the operating limit to be set, given the high level of uncertainty involved in the test. Recognizing that continuous condensable PM monitoring technology does not exist, the commenter's preference is to preserve the flexibility allowed in choosing to reduce condensable PM or filterable PM by setting the operational filterable PM limit based on the difference of the total PM limit and condensable PM measured from stack testing (i.e., filterable PM (operational) = total PM limit (0.03) – condensable PM (performance test)). The commenter believes this approach will provide flexibility and would address both variability concerns with testing, fuel supply and operations.

Response to Comment 78: Given our decision to use a filterable PM standard as the PM emission limit under this rule, this suggested approach would not be appropriate. Moreover, the operating limit established for the PM CPMS is just that – an operating limit, and not a PM limit (filterable or total), and does not require the source to present the monitor output in terms of PM.

18. Request for clarification on multiple load testing (section 63.10007).

Comment 79: Commenter 17316 requests clarification on proposed provisions for multiple load performance tests at section 63.10007 to establish load-specific operating limits. The commenter states that it is not clear which operating limits are re-set following a performance test or whether a new performance test program erases all previous operating limits, or only those operating limits for loads at which testing was repeated. For example, the commenter asks if a unit initially conducted performance testing at 3 loads: 100 percent, 75 percent and 50 percent, but for the next annual test cycle, only conducted testing at 100 percent load to demonstrate compliance, whether the source could continue to use operating limits established in the initial test program for the 75 percent and 50 percent load levels. The commenter believes that it seems appropriate to allow continued use of operating limits for load levels at which testing is not repeated, so long as test results at the maximum load level demonstrate compliance.

Comment 80: Commenter 17767 states that control device operating parameters will vary according to unit output and those parameter levels equating to compliance at high loads might be unacceptable or unnecessary at lower loads. According to the commenter, absent a means to account for an acceptable tolerance in these parameters, the rule allows for multi-load testing but fails to outline what load ranges would be required, how to address operation between those loads and the costs of the testing regiment, which would be high. The commenter recommends adding operating range tolerances as an appropriate solution.

Comment 81: Commenter 17805 states that the section 63.10007 (Tables 5 and 7) contains compliance demonstration requirements, and specifically, demonstration "through performance testing". According to the commenter, these provisions essentially require utility units to develop parametric limits at different operating levels and coal qualities. The commenter asserts that according to this section, stack testing is to be performed while units burn coal with the maximum concentration of HAP constituents, but units would still have to run at normal operating load. The commenter does not believe this would be possible since the commenter has observed that coal with the maximum HAP concentration characteristics generally contains lower heat content. Therefore, the commenter asserts, running a performance test solely with coal having the higher HAP concentrations, and lower heat content, would not allow a unit to attain normal operating loads; numerous stack tests would be required during a single compliance period to determine parametric limits for each seam/quality or type of coal as proposed in the rule and there could be multiple compliance periods in a year depending on a utility's chosen compliance method. According to the commenter, this is burdensome. The commenter states that it would be helpful for the EPA to review data showing HAP concentration variability by coal-type and within coal-type before finalizing these monitoring requirements.

Comment 82: Commenter 17800 states that many units in the U.S. utility system are load following or cycling units that change load on a daily basis and that many of the control device operating parameters the EPA is requiring to be maintained will vary with load. The commenter states that to account for this, the EPA suggests that EGUs obtain differing operating limits at loads other than the "maximum normal load" required for stack testing by testing at those other lower loads (section 63.10007(c)). According to the commenter, requiring EGUs to conduct performance tests at multiple loads is not practical or reasonable, and the EPA has not considered the time or cost of that kind of extensive testing.

Response to Comments 79 - 82: The EPA finds these comments moot, for the rule no longer requires operational limits except for those EGU owners or operators who choose to rely on PM CPMS to demonstrate compliance. To the extent that those owners or operators choose to operate their units at load levels other than normal operating conditions, those owners or operators will need to ensure that their units remain in compliance with the emissions limits, which, as explained in the rule, may mean that additional emissions testing and correlation will need to occur. With respect to the commenter's example, if emissions producing characteristics had not changed since the original correlation testing occurred, the commenter would be able to use the previous correlations for its operating parameters when the unit's load changed.

19. Miscellaneous.

Comment 83: Several commenters (19536, 19537, 19538) states that the monitoring of operating parameters as proposed under some scenarios does not assure continuous compliance with emissions limits that are only measured annually or every 5 years. According to the commenter, the amount of each HAP that is emitted ultimately depends on the amount in the coal, which is not tested more frequently than monthly (or upon a change of fuel type) under any of the compliance scenarios. Moreover, the commenter notes that the HAP content of fuel is highly variable even within fuel types.

Response to Comment 83: We understand that there is variability in the HAP metals content in coal supplies and we believe that we were able to take that variability into account to a large degree with the extensive database of emissions values and the statistical procedures used in establishing the floor and the final emissions limitations. We believe that sources who demonstrate compliance with these limits must apply the control measures including use of fuels that are consistent with the control measures applied by the sources used in developing the limits. The commenter provided no information on how the variability of fuel HAP metals content can vary significantly beyond that found in the database used in setting the floor or to the extent that a source demonstrating compliance under the various compliance monitoring measures allowed in the final rule will have undetected excess emissions.

Comment 84: Commenter 17795 states that the EPA did not provide an explanation for selection of a 12-hour block average for operational monitoring. According to the commenter, the EPA should maintain consistency among averaging periods for demonstrating compliance with emission standards or operating limits; averaging operating parameter data over the same time period when employing direct or surrogate continuous monitoring provides adequate assurance that equipment is operated and maintained in compliance with standards or limits. According to the commenter, this also reduces the data management and the quality assurance burden currently proposed with 12-hour block averaging periods.

Response to Comment 84: This comment is moot given the changes in the final rule. The PM CPMS will use a rolling 30-day average. Site-specific monitoring for liquid oil-fired units, if required, will establish the appropriate averaging period based on the parameters being monitored.

Comment 85: Commenter 17740 states that it has significant concerns with the EPA's proposed testing requirements for solid oil-derived fuel and coal-fired EGUs using total PM emissions as a surrogate for non-Hg metals (*see* 40 CFR section 63.10006). The commenter understands that the purpose of this testing is to ensure that the surrogate (*i.e.,* PM) emission limit meets the direct HAP emission limits and that the EPA reserves the right to adjust the surrogate limit. The commenter asserts that the EPA does not have the authority to "adjust" surrogate emissions standards for individual units based on performance testing. According to the commenter, if the EPA allows sources to comply with emissions standards through surrogates, the surrogate emission standards also are subject to the requirements of the CAA and cites *National Lime II*, 233 F.3d at 639 (holding that the EPA may use PM as a surrogate for HAP if the "PM emission standards reflect what the best sources achieve -- complying with CAA section 7412(d)(3)"). The commenter stats that according to the MACT Floor Memo, the agency set the PM MACT floor for existing units consistent with the requirements of the CAA. MACT Floor Memo, at 3 ("The existing-source MACT floors for PM, HCl, SO_2, total non-Hg HAP metals, and individual non-Hg HAP metals emissions were based on the top 12 percent of the total number of EGUs…"). According to the commenter, nothing in the CAA authorizes the EPA to subsequently review and revise these standards on a unit-by-unit basis.

Comment 86: Commenter 17740 states that Congress specifically limited the EPA's authority to review and revise emissions standards promulgated under section 112. Section 112(d)(6) instructs the Administrator to "review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section…" According to the commenter, the CAA manifestly does not permit the agency to circumvent the requirements of Section 112(d)(3) and set standards for specific units (citing e.g*, Chevron U.S.A., Inc. v. Nat. Res. Def. Council*, 467 U.S. 837, 842-43 (1984) (holding that if Congress has spoken directly to the disputed issue of statutory construction, "that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress"). According to the commenter, if, after issuing a final rule, the EPA determines that a surrogate emission standard is no longer appropriate, the agency must review and revise the standard in accordance with the express requirements of the CAA. The commenter notes that the EPA's position deprives sources of much needed time to plan for capital investments in control technology. The commenter states that a source has no way of knowing whether its emission control measures are sufficient to comply with the EGU MACT if the EPA can review and revise a MACT standard based on performance test results. According to the commenter, even if a source makes substantial capital investments and achieves a proposed surrogate emission limit, it may be forced to make additional investments in a short timeframe to achieve a new, individual limit based on its performance test results. The commenter asserts that this circumstance creates substantial regulatory uncertainty for affected sources.

Response to Comments 85 and 86: The final rule no longer includes the use of PM as a site specific emissions surrogate for HAP metals. Instead, the final rule allows the source to choose and comply with one of three numerical emissions limits- total non Hg HAP metals, individual non Hg HAP metals or filterable PM. The rule no longer requires the source to develop any surrogacy relationship to use one or another emissions limit.

Comment 87: Commenters 17718 and 17881 note that section 63.10005(d)(7) states that initial compliance through the use of CPMS can be determined using the average hourly PM, non-Hg HAP metals, HCl, HF, or Hg concentrations obtained during the first 30-day operating period. In turn, commenters note that continuous parameter monitoring systems, or CPMS, are defined at section 63.2 as "Continuous parameter monitoring system means the total equipment that may be required to meet the data acquisition and availability requirements of this part, used to sample, condition (if applicable), analyze, and provide a record of process or control system parameters." According to the commenters, they have been unable to identify any other place in the proposed rule where it is stated that CPMS can be used for initial compliance, nor does the commenter understand how such monitoring systems could be used for purposes of a direct compliance assessment with the emission limits in Tables 1 and 2 of the proposed rule.

Response to Comment 87: The final rule in this section refers to "CMS", and is referring to continuous emission monitoring systems that are used for direct compliance. Section 63.10005(c) discusses that you may be required to establish an operating limit using a PM CPMS during an initial compliance performance test period.

Comment 88: Commenter 17881 states that under section 63.10011 the concept of selecting the highest minimum/maximum values across a series of performance tests is not congruent with multiple operating limits for different scenarios.

Response to Comment 88: Given the simplification of the operating limit and parameter monitoring provisions in the final rule, the EPA does not believe this comment remains applicable.

Comment 89: Commenter 17881 states that in section 63.10021(a)(1), there needs to be an allowance for operation outside the initial operating limits during subsequent compliance tests for purposes of widening the allowed operating limits without having to report a deviation (as long as the compliance test results show compliance with the emission limit).

Response to Comment 89: The EPA disagrees. Given the 30-day averaging period, there is adequate flexibility for a short term increase in PM CPMS output during a short term test without this type of special allowance.

Comment 90: Commenter 17881 states under Table 4 – Operating Limits for EGUs, for IGCCs the combustor temperature would likely be a better measure, as compared to electrical load (as a percent of maximum output) which will float with ambient conditions.

Response to Comment 90: This comment is moot given the changes to the operating limits required under the final rule.

Comment 91: Commenter 17881 states under Table 4 – Operating Limits for EGUs, with respect to PM CEMS, that for concentration based emission or operating limits, it is normally appropriate to correct the concentration back to a reference O_2/CO_2 level for purposes of consistency (i.e., the diluent gas levels will affect the concentration).

Response to Comment 91: There is no need to report the data from a PM CPMS in PM concentration values.

Comment 92: Commenters 18014 and 17716 state that in Table 8, CPMS data is required to be reduced to 12-hour block averages. However, the commenters assert that this requirement is not specified in section 63.10010(h).

Response to Comment 92: The final rule has eliminated the parameters measured on a 12-hour block average, and now requires only a 30-day rolling average for an operating parameter.

Comment 93: Commenters 18014 and 17716 state the limits for some operating parameters are also internally inconsistent. The commenters provide an example that section 63.10042 defines the minimum operating parameters limits (minimum scrubber effluent pH, minimum pressure drop, minimum scrubber flow rate, minimum sorbent injection rate and minimum voltage or amperage) as 90% of average value measured during the most recent performance test, but Table 4 states that the parameters must be maintained "at or above the lowest 1-hour average" from the performance test. The commenters recommend allowing sources greater flexibility in defining representative operating parameters.

Response to Comment 93: These comments are moot given the changes in the final rule, as discussed above.

Comment 94: Commenter 18015 states that facilities should have the flexibility to use other parameters than the ones identified in the rule. According to the commenter, for example, some units equipped with wet FGD scrubbers have, as the primary parameter for control, density, not pH. The commenter notes that the relative importance of various operating parameters can change depending on conditions and therefore the rule should be flexible in order to account for other operating parameters and account for variability in operating conditions. The commenter recommends that the alternatives should be established through submittal of monitoring plans before testing and certifying CEMS.

Response to Comment 94: These comments are moot given the changes in the final rule, as discussed above. The one circumstance in which the rule relies on flexible parameter selection is for liquid oil-fired units that demonstrate compliance with emission limits for acid gases by conducting quarterly performance tests. In that situation, the source must also develop a site-specific monitoring plan to ensure that operating conditions remain consistent with conditions during the performance test. See the final preamble for further discussion.

Comment 95: Commenter 17925 states that parametric monitoring should be applied as an action indicator and not applied as a compliance monitor because they do not give a true indication of compliance especially for multi-pollutant control configurations. According to the commenter, for example, for PM emissions, the EPA has determined that ESP secondary current and baghouse leak detection will be indicative parametrically of PM filterable emissions. However, the commenter states, other equipment on units such as FGD systems (wet scrubbers) or DSI for ESP ash resistivity adjustment also can serve to reduce filterable and condensable PM emissions. According to the commenter, in such cases, a wide range of ESP secondary power rates and baghouse leak rates could be experienced while PM emission limits are still achieved due to the impact of the other equipment. The commenter does note that if parametric monitoring remains a compliance monitoring method, they agree with the approach of providing a variable range within the tested results. However, the commenter asserts that some additional flexibility beyond a 10% range should be considered. According to the commenter, the EPA does not explain how the 10% number was obtained and how the range would be used for compliance.

Response to Comment 95: These comments are moot given the changes in the final rule, as discussed above. See also response to Comment 30 in this section.

Comment 96: Commenter 17923 recommends that the operational limitations of the air pollution control systems reference the manufacture recommendations. According to the commenter, the methodology required by the proposed rule would significantly limit operational flexibility and significantly increase the emissions testing required at affected facilities.

Response to Comment 96: These comments are moot given the changes in the final rule, as discussed above.

Comment 97: Commenter 17718 states that the proposed regulatory language in 40 CFR 63.10006 (a), (b), (d), (h) and (i), does not allow for process improvements. The commenter asserts that as written, subsequent performance tests must be conducted "during the same compliance test period and under the same process (e.g., fuel) and control device operating conditions." According to the commenter, process improvements discovered after initial compliance testing could potentially allow for the same or better control of emissions yet move the control device operating conditions outside of what was established as the "operating limits" established per Table 4 and 7 of the proposed language. The commenter suggests that the "same process and control device operating conditions" language be removed from these regulatory sections. According to the commenter, this would be similar to language proposed in 40 CFR 63.10006 (e), (f), (g), (j), (k), (l), and (m) where testing under those "same conditions" is not required.

Response to Comment 97: These comments are moot given the changes in the final rule, as discussed above.

Comment 98: Commenter 19033 states that section 63.10010 (h)(2)(i) is overly prescriptive with respect to the minimum acceptable criteria for liquid flow monitoring. The commenter asserts that the +/- 2 percent accuracy (section 63.10010 (h)(2)(i)(B)), is excessive, given the purpose for which liquid flow monitoring is intended (verification that the scrubber is operating in a manner similar to the level at which it operated during the performance test). The commenter points out that in its current Title V permit the liquid input in based on supplied pump curves, which indicate flow as a function of pump motor amperage. The commenter asserts that the proposed regulation also does not take into account that there could be issues with spray patterns as nozzles wear over time. According to the commenter, liquid flow measurements would not take that effect into account and would thus not be an accurate indicator of pollutant removal. The commenter estimates that $250,000 would be needed to add the liquid flow measurement and associated data acquisition systems needed to meet section 63.10010 (h)(2)(i)(B) and that such an expenditure is not justified. The commenter agrees with the concept outlined in the July 29, 2011, comments letter provided with respect this proposed regulatory action by Thomas Easterly, Commissioner of the Indiana Department of Environmental Management, i.e.

> "Indiana asks that States be allowed maximum flexibility to develop alternate compliance plans that afford the regulated community opportunity to assure timely compliance, while also assuring that consumers are not adversely affected."

In concert with the sentiment expressed by Commissioner Easterly, the commenter recommends that states be provided the flexibility to approve liquid flow monitoring and other portions of the required CPMS monitoring plan. To that end, the commenter recommends that section 63.10010 (h)(2)(i) be amended as follows: (i) If you have an operating limit that requires the use of a flow monitoring system***, you must develop a flow monitoring plan in consultation with your state regulatory agency. The plan must be approved by the agency in advance of the initial compliance demonstration*** requirements in (A) through (D) of this section.

Response to Comment 98: As discussed elsewhere, the use of operating parameters is no longer required in the rule except for those associated with use of PM CPMS or those associated with use of liquid oil-fired units whose owners or operators choose acid gas emissions testing and must provide continuous parameter monitoring of their flue gas desulfurization systems. Where operating parameters are used, the rule does not prescribe minimum quality assurance or control specifications; in concert with the commenter's suggestion, these specifications are left to the EGU owner or operator to choose and follow.

Comment 99: Commenter 19033 states that 63.10010 (h)(2)(ii)(D) is overly prescriptive. According to the commenter, EGU operators may have experience that pressure drop sensors may provide reliable output at a less frequent cleaning frequency than daily and alternatively, systems equipped with an auto purge system would not require the daily operator interaction of manually cleaning the sensors. According to the commenter, this parameter is another candidate for negotiation between the state regulatory agency and EGU owner. The commenter recommends that section 63.10010 (h)(2)(ii) be amended as follows:

(ii) If you have an operating limit that requires the use of a pressure monitoring system, you must ***develop a pressure monitoring plan in consultation with your state regulatory agency. The plan must be approved by the agency in advance of the initial compliance demonstration*** requirements in (A) through (F) of this section. ***The plan must include the recommended accuracy, and include a recommended maintenance interval for adequate sensor cleaning if an auto purge system has not been installed.***

Response to Comment 99: These comments are moot given the changes in the final rule, as discussed above.

Comment 100: Commenter 17821 disagrees with the EPA's unwillingness to delegate some key responsibilities to state and local agencies. The commenter states that in section 63.10041, the EPA defines who is responsible for implementation and enforcement of this subpart: "In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

1. Approval of alternatives to the non-opacity emission limits and *work practice standards* in §63.9991(a) and (b) under § 63.6(g).
2. Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and *approval of alternative operating parameters* under §§ 63.9991(a)(2) and 63.10009(g)(2).

The commenter strongly recommends that approval of alternatives to work practice standards and alternative operating parameters be delegated to the state or local agencies for multiple reasons.

According to the commenter, first, the state and local agencies are in a much better position to review and access the merit of changes requested by individual operators; while it can articulate direction for how to approve these requests, the EPA does not have the unit specific knowledge to understand and evaluate the rationale for the requested changes. Second, the commenter states, the EPA has in this proposal, done an inadequate job in developing operating parameter limits for the wide diversity of EGUs. According to the commenter, because of the wide variety in EGU construction, control equipment, and operation, it is unlikely that the EPA can develop a one-size-fits all approach that will properly apply to the entire industry, and as a result, state and local agencies that are more familiar with each source should be allowed to make those decisions. Finally, the commenter anticipates that there will be a large number of these requests and that restricting approval to the EPA will create a terrible delay in their approval that will put sources at a compliance risk.

Response to Comment 100: The EPA disagrees. Under implementation of the NESHAP program, the EPA routinely retains the approval authority over these issues. There is nothing so unique within the EGU sector as compared to all other industries to take a different approach under this rule.

Comment 101: Commenter 17752 requests that the EPA provide guidance on how to operate a baghouse to obtain the three different PM concentrations.

Response to Comment 101: The comment is moot, as the rule no longer requires control device operational parameters to be monitored.

5A05a - Testing/Monitoring: Operating parameter monitoring (bag leak detection systems)

Commenters: 17704, 17716, 17725, 17737, 17775, 17868, 17871, 18014, 18498

Comment 1: Several commenters (17716, 17725, 17775, 17868, 18014, 18498) recommend that the EPA remove the requirement to comply with the procedures in EPA-454/R-98-015. According to the commenters, the referenced document is based on operating and maintenance procedures for a specific type and model of bag leak detector (BLD) and is inadequate for many BLD systems (BLDS). The commenters state that the definition of BLDS clearly allows use of a variety of technologies, including electrodynamic, light scattering, and light transmittance. According to the commenters, the required guidance document excludes all other technologies (e.g., light scattering, light transmission, optical scintillation, and electro-dynamic devices).

Comment 2: Commenters 17775 and 17868 request clarification regarding the applicability of the requirements for fabric filters. The commenters state that although several provisions suggests that BLDS are only required if an EGU "chooses" to demonstrate compliance using a BLDS and cite, as an example, proposed section 63.10011(b), other provisions appear to require any EGU with a fabric filter to employ a BLDS along with any other applicable operating limits (citing Proposed Tables 4-8). According to the commenters, the EPA should issue a proposal that makes clear when a BLDS would be required and to justify that requirement.

Comment 3: Commenter 17704 states that if there is any redundancy such as BLDS for units with fabric filters choosing to comply with PM CEMS, the requirement for the BLDS should be removed.

Comment 4: Commenter 17775 states that the recording alarm time in 1-hour increments is unreasonable. In the case of a broken bag, the most common baghouse failure, alarms can usually be cleared in only a few minutes by removing a single compartment from service.

Comment 5: Commenter 17737 strongly objects to any requirement to use BLDS to demonstrate compliance. The commenter has been operating these devices on two of its units, and they have proven to be extremely susceptible to false alarms. According to the commenters, on numerous occasions (sometimes multiple occurrences in one day) the BLDS have indicated an alarm, following which an investigation reveals no problems relating to particulate emissions or control equipment, and often, the condition is rectified simply by cleaning the probes. According to the commenters, these false alarms add to operational costs and keep plant personnel from their regular duties. The commenter suggests the use of opacity measurement in place of PM CEMS or BLDS as compliance assurance monitors. The commenter notes this would be similar to the requirements of 40 CFR 60.48 Da. According to the commenters, opacity monitors have proven to be reliable in detecting changes in PM emission levels which could trigger an operator investigation of potential malfunctions and take appropriate corrective action. According to the commenter, because there is no reliable numerical correlation between PM emissions and opacity, the opacity monitoring (and the same holds for BLDS, should an operator elect to use them) should be used solely as an indicator and not for compliance. The commenter provided a CAM example using opacity as the indicator and states that such an approach is sufficient to demonstrate continuous control of PM emissions and should be suitable for continuous compliance with the MACT standard for non-Hg metals especially when a control device with efficiencies above 99.5 percent is used for PM control, such as a fabric filter.

Comment 6: Commenter 17871 states that nearly all units are required to install a continuous opacity monitoring system (COMS), either as a result of the NSPS or through the NSR program. According to the commenter, in other rulemakings, the EPA has asserted that while COMS "cannot directly measure PM emissions," a "properly calibrated and maintained COMS is sufficient to demonstrate long-term PM control device performance, since the purpose of the monitoring is to demonstrate with reasonable certainty that the PM control device is operating as well as it did during the PM emissions test used to demonstrate compliance" (In re Newmont Nevada Energy Investment, LLC, PSD Appeal No. 05-04 (EAB 2005) (citing 70 FR 7905, 7908 (Feb. 16, 2005))). According to the commenter, where each unit would be subject to comprehensive and duplicative monitoring schemes, the EPA should refrain from requiring installation of an expensive CEMS that does not provide additional compliance certainty.

Response to Comments 1 - 6: The final rule does not require use of a BLDS for EGUs that employ a fabric filter control device. We believe that continuous monitoring in the form of CEMS, sorbent traps, or CPMS or that frequent emissions testing are appropriate to ensure ongoing compliance with this rule. We also agree with commenters that some of the monitoring provisions in the proposal were duplicative and unnecessary. In order to simplify and streamline the final rule, we have removed most operating parameter monitoring from the final rule. We have retained the owner-defined operating limit monitoring using a PM CPMS as an option to periodic emission testing.

The rule establishes the PM CPMS as an operating limit monitor and not a direct filterable PM emission monitoring requirement that meets PS11 requirements. While we recognize the importance of continued control device performance to ensure emissions minimization, we also are aware that other rules that apply to these units - including but not limited to the operating permits rule, the CAM rule, and the NSPS – already require continuous monitoring in most cases. Those rules will remain in effect so the need to impose additional operating limits monitoring or CEMS on those units is much reduced. For these reasons, the final rule includes no requirements applicable to BLDS.

5A06 - Testing/Monitoring: Application of Hg CEMS

Commenters: 17197, 17383, 17402, 17620, 17621, 17622, 17638, 17675, 17677, 17681, 17690, 17691, 17704, 17718, 17725, 17728, 17747, 17752, 17757, 17758, 17761, 17775, 17800, 17804, 17805, 17808, 17843, 17868, 17877, 17881, 17930, 18014, 18025, 18039, 18421, 18428, 18449, 18498, 18023

1. Requested clarifications and corrections.

Comment 1: Commenter 18014 advises that proposed sections 63.10010(f) and 63.10021(h)(ii) have contradicting requirements for quarterly accuracy determinations and daily calibration drift tests.

Comment 2: Several commenters (17728, 17758, 17775, 17868) state that all references in the proposal to 40 CFR Part 60, Procedure 5 (e.g., section 63.10021(a)(14)(ii)) should be deleted because the quarterly and daily requirements in Procedure 5 are duplicative of and conflict with some of the proposed requirements in proposed Appendix A, and use of Procedure 5 is inconsistent with the EPA's preamble statement that it considered and rejected using Procedure 5.

Response to Comments 1 - 2: The Procedure 5 references have been removed from the proposal so that the Appendix A requirements, based on the CAMR approach, are used for Hg monitoring under this rule, as indicated in the preamble to the proposed rule.

Comment 3: Commenter 17775 states that proposed Appendix A contains a number of provisions that conflict with and/or duplicate requirements of part 63, subpart A, or with other proposed requirements in subpart UUUUU:

1. For example, according to the commenter, proposed section 7.2.2 requires 21 days notice of RATAs, whereas 40 CFR section 63.9 requires 60 days notice of performance evaluations (a term that is defined in section 63.2 to include RATAs).
2. According to the commenter, proposed section 7.2.3.1 requires submission of a monitoring plan 21 days prior to initial certification testing or recertification testing, whereas proposed section 63.10000(d) requires submission of the monitoring plan 60 days before the initial "performance evaluation."
3. According to the commenter, proposed section 7.2.5.5 requires the owner or operator to submit a compliance certification in support of each report based on reasonable inquiry, whereas proposed section 63.10031(c)(2) requires that the compliance report contain a "statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report."
4. Finally, according to the commenter, the data validation provisions in section 5.1.3 conflict with the out-of-control definitions in proposed section 63.10000(d)(6) and Table 9. Specifically, the commenter asserts that Appendix A establishes data validation criteria for Hg CEMS in Table A-3, which sets the acceptance criteria at ≤5.0 percent of span value or ≤1.0 μg/scm, proposed section 63.10000(d)(6) requires development and implementation of a site-specific monitoring plan that "defines a continuous monitoring system that is out-of-control consistent with section 63.8(c)(7)(i)," and Table 9 and section 63.10031(c)(9) also require reporting of periods during which a CMS was "out-of-control, as specified in section 63.8(c)(7)." The commenter states that the term "out-of-control" also is used to determine what data may be used to report emissions and what constitutes a deviation of monitoring requirements under proposed section 63.10020(c) and (d) and that Section 63.8(c)(7)(i) defines "out of control" with respect to a "calibration drift test" as exceeding "two times the applicable CD specification in the applicable performance specification of in the relevant

standard." According to the commenter, this definition is inconsistent with Appendix A. The commenter states that EPA must clarify its proposal regarding the definition of "out of control" and must resolve these (and any other) duplications and inconsistencies, and where a requirement in Appendix A is more detailed or restrictive than a similar requirement in the part 63 general provisions or subpart UUUUU, or *vice versa*, the EPA must explain the need for the more restrictive requirement.

Response to Comment 3: The EPA indicated in the preamble to the proposed rule that its intent was to adopt the CAMR-based requirements for Hg monitoring because many sources had already installed monitors to meet those requirements. Thus, the intent of our proposal was to use these specific requirements in place of the general part 63 Hg monitoring requirements. These requirements for Hg CEMS went through notice and comment rulemaking for the same set of sources. Although CAMR was set aside on other grounds, these technical specifications and QA requirements reflect significant input from stakeholders and analysis by the EPA to establish an appropriate foundation for Hg monitoring at electric utilities under the CAA. For the final rule, we have made conforming changes to ensure that this intent is carried out effectively throughout the rule text and Appendix A, as well as including certain additional clarifications based on the input received in response to this proposed rule.

Comment 4: Commenters 17620 and 17691 state that it is unclear, from the form of the Hg emissions limit and the compliance methodology, whether the EPA intends that the Hg limitations include total Hg or only vapor-phase Hg. The commenters state that according to the proposal, continuous compliance can be demonstrated by the use of Hg CEMS, which measure only vapor-phase Hg and that the EPA also mentions of the use of Method 29 or Method 30B for demonstrating compliance. The commenters state that Method 29 measures total Hg whereas Method 30B measures only vapor-phase Hg. Additionally, the commenters state that in its discussion of allowable certification methods for Hg CEMS, the EPA references the use of the Ontario Hydro Method or EPA Method 29, each of which measures total Hg.

Comment 5: Several commenters (17804, 17843, 18039) state that it is not appropriate to allow compliance demonstrations without accounting for particulate bound Hg which can be a substantial fraction of total Hg emissions. The commenters have determined that the filterable portion of total particulate emissions for coal-fired EGUs without wet scrubber controls can produce an average of 30 percent- 40 percent filterable PM. The commenters recommend that the EPA require total Hg emissions to be the basis of compliance demonstrations by taking into account the average particulate bound Hg measured during the most recent stack test on that unit in combination with the total vapor-phase Hg measured by the CEMS until such time as Hg CEMS to measure particulate-bound Hg are installed at a unit. Commenter 17853 provides as an example the Massachusetts Department of Environmental Protection's final Hg emissions regulation at 310 CMR 7.29(5)(a)3.g.ii.

Response to Comments 4 - 5: The Hg emissions limits were established based principally on the results from Method 30B emissions tests (vapor phase Hg) coupled with data from some Method 29 test programs. Though the Method 29 results would include the particulate fraction, this generally constitutes less than 5 percent of the total Hg. The final rule then requires continuous monitoring for units firing fuels other than liquid oil using either a Hg CEMS or a sorbent trap monitoring system both of which measure vapor phase Hg concentration. The final rule allows for the use of Method 29, the Ontario Hydro Method, or Method 30B if the source elects to use such methods when emissions testing a liquid oil-fired unit. Method 29, Method 30B, or Ontario Hydro Method testing for Hg is not applicable for other types of affected units.

Comment 6: Commenters 17718 and 17781 request clarification with respect to section 63.10005(e). The commenters state that under this section there is no mention of beginning to use data obtained during the first 30-day operating period "after the monitoring system is certified," though this language does appear in similar monitoring system sections (i.e., 40 CFR 63.10005(d)(4)-(6)). The commenters note that there are sorbent trap monitoring system certification requirements (e.g., RATA) mentioned in the proposed "Appendix A to subpart UUUUU – Hg Monitoring Provisions." The commenters question whether it was the EPA's intent that data should not be used until the initial certification is completed. Commenters also state that the EPA should clarify whether if sorbent trap monitoring systems are certified prior to the compliance date the "30-day operating period" for determining initial compliance begins on the compliance date. Commenter 17781 believes that any 30-day period within the first 180 days following the applicable compliance date should be allowed for the initial compliance demonstration.

Response to Comment 6: This concern has been addressed by clarifying the language in the final rule.

2. Technical review of appendix A and incorporation of part 75 provisions.

Comment 7: Several commenters (17752, 17775, 18014) find similarities between Hg CEMS requirements in Appendix A and the now-vacated CAMR provisions of Part 75. The commenters generally support attempts to provide consistency between the proposal and Part 75, but Commenter 17775 does not believe all of the Part 75 requirements are necessary in a MACT standard or that the proposal established that all requirements can be consistently met. Commenter 17775 incorporates a memorandum by McRanie Consulting with the following technical recommendations for proposed Appendix A:

1. The consultant recommends adding language that specifically allows for use of backup monitors. Commenters 17752 and 18014 also support such a clarification and commenter 17775 states that such language should apply to both Hg CEMS and sorbent trap systems. Several commenters (17752, 17775, 18014) also recommend incorporation of provisions for use of like-kind replacement components and backup instruments as provided in sections 75.10(e) and 75.20(d). Commenter 17775 believes these provisions are necessary to minimize data loss during periods when an instrument must be returned to the factor for repair. The consultant believes that a 720-hour like-kind replacement provision is essential to maintaining acceptable Hg CEMS availability.
2. The consultant and commenters 17752 and 17775 also recommend that more widespread use of grace periods should be in the final rule; commenter 17752 believes that a 720-day grace period for like-kind replacements should be sufficient for required factory repairs and that a grace period of at least 24 hours is needed for weekly system integrity checks. Commenter 17775 believes that the system integrity test is likely to be one of the most challenging tests because EGUs subject to the test under state programs have reported frequent failures and the need for manual performance so that a technician can observe the process and identify problems during the test. According to commenter 17775, these issues led Northeast States for Coordinated Air Use Management, (NESCAUM) to conclude:

    At this point, it appears that the equipment associated with the system integrity tests may not yet be at the point where the test can be performed in an automated fashion with high reliability. This affects how the tests can be scheduled because a technician needs to be available to monitor them.

Commenter 17775 states that if the system integrity test cannot be automated, EGUs will need to monitor operating hours to determine when a test will be due, and ensure that a qualified technician is available because most EGUs do not have technicians available to perform routine tests on nights and weekends. According to the commenter, even if the test is scheduled to be performed on time, issues with monitoring system breakdowns and the time necessary to complete maintenance could also result in late tests. Commenter 17775 states that the proposal provides no basis for specifically excluding the test from grace period provisions, and the commenter requests at a minimum that the final rule include an operating hour grace period of at least 72 unit operating hours before data are invalidated because that would provide an EGU time to schedule and perform a test if one were triggered unexpectedly by a unit startup or shutdown, and such a grace period would be consistent with provisions for linearity checks, 3-level system integrity checks, and RATAs. Commenter 17775 suggests that another possible approach would be a calendar day interval for testing combined with an operating hour grace period to provide relief if the unit is not operating or the monitoring system is out of service when the test is due. According to the commenter, if the EPA does not provide some sort of flexibility, the availability of valid Hg CEMS data for compliance calculations may be needlessly limited simply due to late tests that do not indicate any actual problem with the monitoring system or data quality.

1. The consultant recommends removing the second sentence of section 3.1.7 because the recommended nominal span ratio yields a span that, according to the consultant, "makes it impossible to comply with many of the other QA/QC requirements of this appendix because the available NIST traceable Hg calibration gas concentrations are not compatible." The consultant also points out that the second sentence of section 3.1.7 is inconsistent with section 3.2.1.4.2, and commenter 17775 emphasizes how important these sections are for specifying appropriate rounding procedures for establishment of span because of the current unavailability of NIST traceable Hg calibration gases at lower spans. Commenter 17775 requests that the final rule include such rounding provisions
2. The consultant recommends removal of the "level detectable" and "detectable limit" terms in sections 3.1.8 and 3.2.1.2.2.1 because "detection limit" is not defined and the meaning of the rule language is unclear.
3. The consultant and several commenters (17752, 17775, 18014) request that the final rule incorporate cross-references to Part 75 for measurements required under Appendix A that are already required under Part 75. Commenter 17775 believes that cross references are preferable to paraphrasing of the Part 75 requirements in the final EGU MACT rule. The consultant presents an example, in proposed Appendix A section 3.2.3.3, where the text specifies span requirements for CO_2 and O_2 monitors using terms and concepts that are used under Part 75, but that are not used or defined elsewhere in Appendix A. Commenter 17775 refers to the consultants review states that since these provisions are incomplete and potentially inconsistent with Part 75 provisions, operators that already are complying with Part 75 should have the option of simply meeting the Part 75 requirements. The consultant also states that references to MPC should be removed from Appendix A because "MPC has no meaning for O_2, CO_2, or stack flow rate in this proposed rule because there is no data substitution."
4. The last sentence in section 4.1.1.3 should refer to Table A-1.
5. The consultant believes that the value of "0.03 µg/dscm" in section 4.1.1.5 should be "0.02 µg/dscm" to be consistent with both PS-12A and Method 30B, and the consultant recommends adding a statement in section 4.1.1.5 invoking the acceptance criteria of PS-12A and Method 30B.
6. The consultant recommends revising section 4.1.1.5.1 to adopt Part 60 and Part 75 language that says more than nine runs can be performed but a maximum of 3 can be discarded.
7. The consultant recommends removal of references to PS-6 because he is concerned that references to PS-6 in Section 4.1.1.5.2 will lead operators and testing companies to the misconception that all of

PS-2 applies to Appendix A procedures. The consultant further recommends that the final rule include the relative accuracy calculations in Appendix A.

8. The consultant believes there are problems units of measure and dry and wet bases within section 12 of PS-2 with respect to proposed Appendix A that are likely to create confusion and recommends adding the following sentence to section 4.1.1.5.2, "For purposes of calculating the relative accuracy, ensure that the reference method and monitor data are on a consistent basis, either wet or dry." The consultant states that these comments are also relevant to section 4.1.2.3.
9. The consultant relays recent exchanges between the agency's testing personnel and source testers conducting Method 30B and PS-12B at units with very low Hg concentrations. According to the consultant, the "breakthrough" specification is not achievable as Hg concentrations approach zero. Commenter 17775 states that for concentrations < $0.5 \mu g/m^3$ but > $0.1 \mu g/m^3$, the alternative breakthrough criteria could be < 50 percent of the section 1 Hg mass. For concentrations < $0.1 \mu g/m^3$, there would be no breakthrough criteria and the validity of the samples would rest on all other performance specifications being met. A consistent achievable alternative specification also should be provided in Method 30B. Commenter 17775 requests promulgation of revisions concurrent with finalization of subpart UUUUU, or complete a rulemaking to revise PS-12B and Method 30B well in advance of the subpart UUUUU compliance deadline.
10. The consultant encourages the agency to expedite publication of the "codes" referenced in proposed Appendix A for various parameters to facilitate development of reporting software by venders.
11. The consultant believes that references to "...tests described in paragraphs 7.1.10.3 through 7.1.10.6 ..." should be corrected to "...tests described in paragraphs 7.1.10.1 through 7.1.10.6 ..." but generally finds section 7.1.10 to be confusing.
12. The consultant states that section 7.2.5.3.3 requires electronic reporting of "The information in paragraphs 7.1.2 through 7.1.19 ...." but advises that there are no sections 7.1.11 through 7.1.19.

Several commenters (17752, 17775, 18014) state that the EPA should consider adding provisions for conditional data validation in the final rule similar to section 75.20(b)(3)(ii)-(vi); Commenters 17752 and 17775 also state that setting data as conditionally valid following the calibration error test (or other maintenance activities that require further QA procedures) is a good provision for improving data availability.

Response to Comment 7: The EPA acknowledges commenters' general support for finding consistency with Part 75. For the items concerning backup monitoring and conditional data validation, the EPA agrees and has made changes to the final rule and Appendix A to provide for backup monitoring and conditional data validation similar to part 75 approaches. For the concerns raised with the system integrity check requirement, the final rule retains the weekly system integrity check requirement, without a grace period. However, to add flexibility, the required frequency of the test has been changed from once every 168 operating hours to once every 7 operating days. Operating days are much easier to track than operating hours. The test can be done at any time during the 7th operating day, rather than requiring it to be done at a certain hour. We believe that this added flexibility will allow utilities to schedule the test in accordance with the technician's work schedule.

For item 1, the EPA has added a cross reference in section 3.1.7 to section 3.2.1.4.2 with respect to rounding in order to provide for consistent implementation. For item 2, the EPA notes that the use of zero gases for calibration is a well-understood concept within the industry. The rule language has been revised slightly to provide for a workable standard that can adjust over time as industry-standard detection limits may change. For Item 3, the EPA agrees, and has made a number of changes to provide direct references to Part 75 in Appendix A in lieu of specifying comparable provisions in this rule. For the specific recommendations in items 4 through 12 above, the EPA has made conforming revisions generally consistent with these clarifying suggestions. In particular, the absolute value relative deviation specification for paired Method 29 or Ontario Hydro method sampling in section 4.1.1.5 has been changed to 0.2 µg/dscm to be consistent with Method 30B. Section 4.1.1.5.2 has been revised to ensure that RATA data are compared on a consistent moisture basis. Regarding the recommendation for an alternative "breakthrough" specification for Method 30B and PS-12B, the EPA plans to propose, in revisions to Method 30B, the alternative breakthrough specifications suggested by the commenter to be applicable to relative accuracy testing. The EPA does not plan to modify the breakthrough specifications for compliance testing applications of Method 30B as it is important to maintain tight specifications even at low levels; testers will need to use longer sampling times or more low background sorbents if the breakthrough criteria cannot be met. We have also modified section 4.1.2.2 of Appendix A to include the alternative breakthrough specifications suggested by the commenter for relative accuracy testing of sorbent trap monitoring systems; the agency will consider revising PS-12 B at a later time as part of ongoing evaluation of that performance specification. The EPA will be proceeding with ECMPS modifications with appropriate reporting codes as the commenter notes is needed.

Comment 8: Commenter 18449 states that many of the assumptions and regulations regarding "Span" date back a generation or more when chart recorders and 4-20 mA links were commonly used. According to the commenter, in those days, readings exceeding the "Span" value resulted in invalid data, and the chart recorder or the 20 mA loop pegged, clamping the data at the maximum span value. The commenter notes that much has changed with both instrumentation and data acquisition systems. According to the commenter:

1. All of the commercially successful Hg CEMS are atomic fluorescence (AF) based and are linear over a very wide range. (e.g., Tekran: 0.01 – 300 µg/m3)
2. The systems operate linearly over this range as one span range. (i.e., There are no range knobs, or other adjustments required to obtain this range.)
3. They report digitally, such that the actual concentration value is reported. There is thus no loss of accuracy in transmitting this wide range of values.
4. The systems report with an "overload" flag when they finally reach their limits, positively identifying periods of invalid data.
5. Provided that a CEMS can demonstrate good (i.e., low) zero readings, using a higher concentration gas to calibrate a Hg CEMS does not affect its low concentration accuracy. For example, states the commenter, calibrating an AF based CEMS using a 9 µg/m3 calibration gas will not cause it to read a subsequent stack concentration value of, say 1 µg/m3 any less accurately than having calibrated it with a 4.5 µg/m3 calibration gas; in fact, the 9 µg calibration gas would probably yield a more accurate number since the uncertainty of the actual cal gas concentration is smaller at higher concentrations. (According to the commenter, this is largely a function of the uncertainty that NIST can provide.)

Commenter 18449 states that, despite the past practice, any requirement to run dual spans is totally unnecessary for Hg CEMS. The commenter notes:

1. Each span range requires independent QA/QC. This requires three separate concentrations of elemental and ionic calibration gases for each span. This would double the QA/QC time required, resulting in more periods of missing data.
2. All CEMS use gas generators rather than bottled gases, but these generators operate over a limited range limitations. An elemental generator that is designed to produce sub-microgram levels may be different than one that produces say 100 ug/m3 for the occasional high peak.

3. Many systems have separate ionic calibrators. If two ionic calibrators are required, the total could become four separate calibrators per system, which is impractical.

The commenter believes the EPA should take this opportunity to finally address this issue in a rational manner. According to the commenter, calibration of Hg CEMS should be at the normal (low level) span range to maximize accuracy. Manufacturers should be allowed to demonstrate the dynamic range of their instrumentation. The commenter states that if an instrument calibrated at a normal span range was shown to be capable of measuring a much higher concentration accurately, (within x percent) the data would be deemed valid no matter how much it exceeded the span value. According to the commenter, this might take specialized generators capable of producing high output concentrations, and a factory "type approval" or one time on-site demonstration would be sufficient.

Response to Comment 8: The EPA agrees that dual range Hg CEMS are not a requirement of this rule. Appendix A of this rule provides guidance and requirements for establishing the span value and full-scale range for monitoring with a Hg CEMS. The span value is established based on the Hg concentration corresponding to the applicable emission limit. Establishing the range will require identifying the Maximum Potential Concentration (MPC) which defines the full-scale range that the Hg CEMS being used must be capable of monitoring.

Comment 9: Commenter 17800 states that it is unrealistic to require submittal of hourly Hg data in a format that this similar to part 75 (see Appendix A section 7.2). The commenter notes that in the Cement MACT the EPA has not required the submittal of hourly data for any of the CAA section 112 listed pollutants. According to the commenter, the reporting requirements in these rules rely solely on the recordkeeping and reporting requirements contained in 40 CFR part 63, subpart A and 40 CFR part 60, subpart A. The commenter states that in the proposed Utility MACT rule, compliance with the Hg limit is determined on a 30-day rolling average and thus the need for hourly measured Hg concentrations is superfluous and the EPA has provided no reason for this treatment. The commenter recommends the EPA revise Appendix A to subpart UUUUU and require only semi-annual reporting of what is required in 40 CFR part 63, Subpart A.

Response to Comment 9: The EPA has retained the hourly reporting of CEMS data, using the ECMPS approach as outlined in the proposed rule. This approach was supported by a number of commenters. See further discussion of this decision under responses to comments in 5B03 of this document.

Comment 10: Commenter 17800 states that the EPA's assumption that there would be little or no cost for flow, CO_2 or O_2, and moisture monitors is invalid (see 86 FR 25033). The commenter notes that its part 75 monitors do not have moisture monitors and adding them will be an added expense.

Response to Comment 10: Moisture monitoring is not required but is an option for use in calculating emissions in units of the emission limit. The EPA expects that units that currently have moisture monitors installed under part 75 may use those under this rule, but that other sources will use one of the other options available, such as a moisture default value.

Comment 11: Commenter 17877 states that weekly system integrity checks should be eliminated and are unnecessary to demonstrate compliance with a not-to-exceed limit. According to the commenter, the existing CAMR performance criteria were created under the auspices of a cap and trade program. The commenter states that performing the standard ongoing QA tests that are deemed sufficient for the Acid Rain Program (daily calibrations, quarterly linearity checks, and annual RATAs) would be appropriate and simplify ongoing QA tests to a consistent set of requirements. Further, according to the commenter, system integrity checks introduce a safety hazard due to the use of chlorine and historically have been very difficult to pass with the current maturity level of the monitoring technology. The commenter states that at a minimum, a qualified technician would have to be devoted to a full day each week in order to try and complete a successful integrity check and that many more man-hours are already going to have to be devoted to maintain CEMS for utilities that will also be operating PM and HCL monitors. The commenter suggests that as an alternative to a weekly integrity check, a quarterly sorbent trap test (in non-RATA quarters) along with the quarterly linearity check.

Response to Comment 11: The EPA disagrees and has retained the proposed requirement for weekly system integrity tests if the CEMS uses a converter and if daily calibrations are not done with a NIST-traceable source of oxidized Hg. The system integrity test assesses the efficiency with which the converter reduces oxidized Hg to elemental Hg; conversion efficiency must be confirmed as poor efficiency would result in a low bias in the Hg measurements. The EPA also disagrees with the labor hour assumptions for this test. At least one vendor has developed an automated solution to the weekly system integrity checks. In addition, to add flexibility, the required frequency of the test has been changed from once every 168 operating hours to once every 7 operating days. Operating days are much easier to track than operating hours. The test can be done at any time during the 7^{th} operating day, rather than requiring it to be done at a certain hour. We believe that this added flexibility will allow utilities to schedule the test in accordance with the technician's work schedule.

3. Achievability of Hg performance specifications.

Comment 12: Commenter 18023 states that Hg CEMS are not capable of achieving the data availability of CEMS for other pollutants because Hg presents unique problems. According to the commenter, first, Hg levels are being measured equivalently in parts per trillion (ppt) whereas other pollutants are measured on a parts per million (ppm) basis, Hg has a tendency to adsorb and desorb from the sampling system, and the measurement technology requires considerable time to stabilize following maintenance. According to the commenter, during that period of stabilization, significant drift (false trending of data) can occur making accurate reporting of data nearly impossible. The commenter states that currently, Appendix A of the proposed rule contains only the requirement that entities report when data is unavailable And Appropriately, the rule does not set a percentage of time for how often data is required to be available. According to the commenter, utilities do not have sufficient experience in operating Hg CEMS, and with all of the QA requirements expected, it is difficult to estimate what an appropriate availability limit would be. Commenter 18023 suggests that therefore the EPA should allow utilities to gain several years of experience with these systems and the requirements of the final rule and then revisit the availability question through a notice and comment rulemaking after a request for information from the industry.

Comment 13: Commenter 17775 recollects previous court challenges to Hg CEMS requirements under CAMR in *UARG v. EPA*, No. 06-1394 (D.C. Cir. 2006) regarding the viability of Hg CEMS technology. Commenters (17775, 17728) state that data availability is a concern based on a report in the docket (EPA-HQ-OAR-2009-0234-14040) entitled "Technologies for Control and Measurement of Mercury Emissions from Coal-Fired Power Plants in the United States: A 2010 Status Report, Northeast States for Coordinated Air Use Management, July 2010." According to the commenter, this report notes the existence of reasonable concerns about the reliability of Hg CEMS and that, in general, availability is a concern for new technology. The commenters state that the proposal did not provide data to establish consistent achievability of all proposed specifications for Hg CEMS.

Response to Comments 12 - 13: The final rule does not specify a data availability requirement; however, the rule does specify that CEMS must be operated at all times that the affected unit is in operation (except for CEMS malfunctions and QA checks). The agency believes that the record indicates adequate availability of Hg CEMS necessary to comply with the final standards. To the extent that a facility does not believe the CEMS can function to provide adequate data availability at a particular source, the facility may elect to use a sorbent trap monitoring system and/or a backup monitoring system.

Comment 14: Commenters 17677 and 17681 relay experience measuring Hg emissions since 2008 using a dilution-extractive CEMS and state that the proposed Hg limit is below accurately measureable concentrations. Through RATA one commenter asserts significantly increased error as the Hg emission levels decline to less that 3 ug/m3. The commenter states that as allowed in the Hg CEMS RATA regulations, emissions less than 5 ug/m3 are allowed an alternate allowance from relative accuracy and given a plus or minus 1.0 ug/m3 difference from the EPA method 30B sorbent trap reference method result and that the proposed rule sets the Hg limit well below the accuracy capabilities of Hg CEMS. The commenter contends that the proposed limit is fundamentally immeasurable and states that the EPA should set a Hg emission level that is measurable and supported by sound scientific data pertaining to CEMS technology.

Comment 15: Several commenters (17638, 17681, 17930) state that Hg CEMS are not sufficiently accurate or reliable at the EPA's proposed emission levels to justify their use. Commenter 17930 states that the UV lamps in Hg CEMS are particularly troublesome and that problem, along with others, results in numerous failures of the CEMS.

Comment 16: Commenter 17675 describes agreements with the state permitting authority to reduce Hg emissions and the associated experience with Hg CEMS on coal-fired EGUs. According to the commenter, these systems provide accurate and audited continuous monitoring for Hg emissions. Even though these CEMS are currently state of the art, the lower limit of quantification for these CEMS and other similar technology is very near the Hg level required to be achieved in stack gases by the proposed Hg limits as documented in a recent study report by Dennis Laudal of the Energy & Environmental Research Center at the University of North Dakota titled "DETERMINING THE VARIABILITY OF CMMS AT LOW HG LEVELS". The commenter states that while it is likely that the quantification limits of Hg CEMS will improve as more systems are installed to monitor for compliance with the MACT standards, EGUs subject to these proposed standards that prefer to install CEMS early may be forced to install sorbent traps to be assured that the systems will meet MACT monitoring requirements. Commenter 17675 believes that sources that have already installed Hg CEMS should be given an automatic extension of the Hg monitoring requirements if the CEMS that are already installed need to be upgraded to meet the EPA's monitoring requirements.

Comment 17: Commenter 17728 relays experience with Hg CEMS operating on side-by-side sister units and states that the instruments do not yield comparable results for unknown reasons.

Response to Comments 14 - 17: If for a particular source, a facility believes that a Hg CEMS cannot achieve the performance requirements needed to satisfy the final standards, the facility may elect to install and use a sorbent trap monitoring system to monitor for continuous compliance. There are data in the draft report cited by one of the commenters, "DETERMINING THE VARIABILITY OF CMMS AT LOW HG LEVELS," that demonstrates reasonable performance of at least one Hg CEMS at Hg levels below 1.0 ug/m3 down to approximately 0.1 ug/m3.

Comment 18: Commenter 17725 states that based on their experience with eight installed Hg CEMS at three facilities in New York, the cost to operate and maintain these systems are not warranted given obvious compliance. According to the commenter, in general, CMMS are expensive to operate and maintain, there is a limited pool of qualified support contractors, they are tricky to install, difficult to operate correctly, and, since the installation of baghouses at Dunkirk and Huntley, the concentrations are so low that we are not always confident of the results even when the calibration and all requirements are met. The commenter states that if the CMMS had been required under CAMR, the commenter suspects that resolving the problems would have been very difficult. The commenter recommends a reduced monitoring plan if facilities can demonstrate *de minimis* emissions.

Response to Comment 18: The LEE provisions in the final rule allow for reduced monitoring for many facilities with very low emissions. The EPA believes those provisions allow for cost-effective monitoring where sources have very low emissions.

Comment 19: Commenter 17761 states that based on their more than 4 years of experience with Hg CEMS at the Scott Energy Center Unit 4 Hg CEMS can overstate actual emissions, demonstrates significant variability, does not necessarily correlate with stack testing measurements (20-25% higher than through stack testing), and will have difficulty meeting the aforementioned 95% availability requirements.

Response to Comment 19: See response to Comments 12 and 13 above.

Comment 20: Commenter 17805 states that based on their experience with Hg CEMS they have found the system to challenging and the company is still working with the Hg CEMS vendor to resolve monitor issues. Based on this, the commenter states that it is still appropriate for the EPA to allow alternative methods of demonstrating compliance. The commenter further notes that the EPA should confirm with suppliers and vendors that all necessary Hg NIST traceable calibration gases are available. The commenter also believes the certification requirement for the monitoring system NIST certified calibrator by an offsite third party vendor will create challenges for systems already installed under state-specific requirements. The commenter recommends the EPA work with state agencies to coordinate these requirements.

Commenter 17805 agrees with the EPA that application of a bias adjustment for Hg emissions is not necessary. It is the commenter's understanding that a bias adjustment, as used for SO_2 emissions in the Acid Rain Program, was primarily intended to assist with ensuring emissions were adjusted properly for cap and trade of emissions. Since Hg will not be traded, the commenter opines that bias adjustment is not necessary.

Response to Comment 20: The EPA has developed the approaches to Hg CEMS calibration including NIST traceability of elemental and oxidized Hg gas generators based on its work with NIST and numerous other stakeholders. To the extent that the commenter or others believe an alternative calibration approach can provide equivalent results, then the commenter may apply for an alternative method under the provisions of section 63.7(f).

Comment 21: Commenter 17690 states that because New York State requires Hg CEMS they are in a unique position to comment on the proposed rule's continuous compliance requirements. The commenter believes that all of the proposed additional monitoring requirements are similar to the New York requirements in that they represent the specification of an advanced technology that does not have a long and widespread history. The commenter states that while the testing equipment vendors may argue that their monitoring systems are fully functional, the commenter's experience is that for these types of applications the vendor infrastructure, industry capabilities, and even regulatory understanding and support are inadequate to meet the compliance schedule in the proposed Utility MACT rule. Further background information and detail to this comment are provided in Appendix 2 (see EPA-HQ-OAR-2009-0234-17690-A1.pdf for Appendix 2 pg 21.) The commenter provides the following observations and recommendations:

1. Commenter agrees that it is appropriate to harmonize monitoring and reporting requirements, to the extent possible, with those of 40 CFR Part 75.
2. Commenter supports the option to simply integrate air toxic emissions data and QA test results into the existing 40 CFR Part 75-compliant data acquisition and handling system computers already in place. However, we would prefer to use the 40 CFR Part 60 deviation-based reporting approach because acid gas, metal and PM hourly measurements have little value; ultimately, long-term totals are of greater value in determining impact.
3. According to the commenter, it is appropriate to use the existing Emissions Collection and Monitoring Plan System (ECMPS) infrastructure for reporting air toxics data and QA test results but commenter does not believe that is appropriate to develop a different reporting system.
4. Commenter supports disabling the bias adjustment for all air toxics data because bias adjustment is only appropriate for emissions trading programs.
5. Commenter agrees that hours when a monitoring system is out of service should simply be counted as hours of monitor down time, to be counted against the percent monitor availability.
6. Commenter favors the EPA's proposed streamlined continuous compliance approach and suggests that if this program were to integrate the Clean Air Markets Division (CAMD) staff experience to the maximum extent possible that the reporting process will be user friendly and efficient.
7. Commenter recommends adding at least 2 years to the final implementation date for the continuous monitoring requirements. During the extended implementation period, affected sources should provide documentation of procurement, installation and testing progress. The EPA and NIST should develop the necessary traceability protocols and testing programs necessary to support widespread air toxic continuous monitoring programs. It would also be appropriate to try to develop sorbent trap methodologies for air toxics.
8. Commenter recommends that if continuous monitoring at any affected source finds that the majority of observations are less than a certain level then the source should have the option to discontinue continuous emission monitoring and replace it with regular stack testing and compliance assurance monitoring. For example, for Hg, that certain level should be 2 μg/m3.

Response to Comment 21: The EPA largely agrees with the comments related to the use of ECMPS and electronic reporting of data. See further discussion under section 5B04 of this document. The EPA disagrees with the need for an additional 2 years for compliance with the monitoring requirements. Compliance with the final rule is 3 years following promulgation, which should provide sufficient time for continued advancement of Hg CEMS monitoring technology, which has already been demonstrated successfully at numerous facilities. For the bias adjustment comments, see response to Comments 40 and 41, below. Regarding data availability, see response to Comments 12, 13, and 19, above.

Comment 22: Commenter 18014 states that the proposal does not justify the burden of requiring ECMPS reporting because the data reporting requirements in Appendix A for Hg go far beyond what is necessary. According to the commenter, the EPA portrays this proposed reporting requirement as easy and that sources would "simply integrate Hg emissions data and QA test results into the existing Part 75-complianct DAHS." According to the commenter, the EPA creates a false dichotomy stating that it considered two options:

1. For deviation and data assessment reports, sources would “need to have a data handling system(DAHS) that: (1) Is programmed to capture data from the Hg CEMS; (2) uses the criteria in Appendix F to Part 60 to validate or invalidate the Hg data; (3) calculates hourly averages for Hg concentration and for the auxiliary parameters (e.g., flow rate, O_2 or CO_2 concentration) that are needed to convert Hg concentrations to the units of the emission standard; (4) calculates 30 boiler operating day rolling average Hg emission rates; and (5) identifies any deviations that must be reported to the agency.”
2. “Simply integrate Hg emissions data and QA test results into the existing Part 75-compliant DAHS” and submit data through ECMPS. After presenting these two options, the EPA states that it obtained “feedback from several DAHS vendors” who suggested the cost of the second option was “similar, and some cases, less than the cost of the first option.”

According to the commenter, however, any software under Option 2 would have to do everything the EPA described under Option 1. The commenter asserts that sources would likely integrate the new requirements within the DAHS that they currently use for Part 60 and Part 75 reporting but this does not mean that the proposed reporting scheme would be simple or cheap to implement.

Response to Comment 22: The EPA disagrees. As other commenters have stated generally, the use of a unified approach to CEMS reporting under this rule and the Part 75 reporting already conducted by the affected EGU population provides a straightforward and consistent reporting method for the industry.

Commenter 17805 supports using a Hg CEMS to demonstrate continuous compliance and has been operating and maintaining a Hg CEMS to report emissions at the Lewis & Clark Station to the Montana Department of Environmental Quality for about 2 years. However, the system has been challenging and the company is still working with the Hg CEMS vendor to resolve monitor issues, and therefore, it is still appropriate for the EPA to allow alternative methods of demonstrating compliance.

Comment 23: Commenter 17626 states that Hg limits need to be set to be consistent with the technology not only for control but for reliable and accurate measurement. The commenter believes that the proposed levels may be theoretically achievable, but current monitoring technology and standardization does [not] exist to measure these levels accurately and precisely. According to the commenter, this places the supplier in the position of being unable to guarantee such performance. The commenter notes it is not a not a measurement supplier but supports the position taken by such organizations as the Institute of Clean Air Companies (ICAC) to resolve these issues.

Response to Comment 23: If for a particular source, a facility believes that a Hg CEMS cannot achieve the performance requirements needed to satisfy the final standards, the facility may elect to install and use a sorbent trap monitoring system technology to monitor for continuous compliance. See section 5A06 for further discussion of Hg CEMs and sorbent trap monitoring.

Comment 24: Commenter 17637 states that it is not precisely determined whether test methods exist that are accurate, reliable and consistent enough to ensure compliance with the stated emission limits. Hg stack testing and other on-line measurements have not been fully developed to provide an accurate, repeatable and reliable level of Hg emissions. According to the commenter, although a performance specification has been proposed by the EPA, the hardware to support such a standard in the day-in-and-day-out environment is still unproven.

Response to Comment 24: The EPA disagrees that the test method and monitoring hardware are not fully developed to meet the stated emission limits in the final rule. Performance Specification 12B which is required in the rule along with Performance Specification 12A which has similar hardware requirements to those in the rule have both been promulgated since September 9, 2010 (75 FR 54970). See 5A06 in this document for further discussion of Hg CEMS and sorbent trap monitoring.

4. QA requirements for elemental and $HgCl_2$ generators.

Comment 25: Commenter 17197 has concerns with Appendix A, section 3.2.1.2 Reagent and Standards Requirements and sections 3.1.4 and 3.1.5 based on experience with an Hg CEMS since 2007. The commenter has concerns with the referenced NIST traceability protocol's 8-quarter recertification interval for $HgCl_2$ "user generators" because these interim protocols will require the "user generators" to be removed from the Hg CEMS and sent to the manufacturer for recertification. According to the commenter, these calibration gas generators are integral components of the TEKRAN Hg CEMS and are not easily removed or reassembled. The commenter states that the TEKRAN Hg CEMS is not designed to accept calibration gas from a generic "Field Reference Generator," or cylinder gas standard (NIST transfer standards) and that recertification of the "user generators" may require that many of their subassemblies (gas and liquid flow meters, temperature controllers) be calibrated to NIST reference methods. According to the commenter, this requires specialized equipment and knowledge generally available only from the manufacturer and consequently, the "send-to-manufacturer-for-recertification" prerequisite is the only real option provided under the interim protocols. According to the commenter, this option presents significant challenges, costs, and risks because the sequence of removing the user generator, installing the temporary user generator, configuring the DAHS for the temporary user generators, and then reinstalling the recertified user generator and reconfiguring the DAHS for the recertified user generators is very complex. The commenter states that specialized TEKRAN knowledge is required for these certification activities. A significant concern for the commenter is the potential for generator and Hg analyzer contamination, and equipment damage during disassembly, shipping, and reassembly. According to the commenter, the elemental and $HgCl_2$ generators contain very delicate subassemblies that can be damaged in shipping, which may affect the recertification. The commenter states that to help ensure proper Hg CEMS operation, onsite equipment vendor technical assistance would likely be required to install the temporary user generators and to reinstall the recertified user generators. The commenter believes that the significant costs, technical challenges, and equipment risks associated with the interim NIST traceability protocol's user generator recertification interval provisions are overly restrictive. Consequently, the commenter advocates that the proposed NIST traceability specifications referenced in Appendix A only become effective when they become final and that the *"... or an interim version of that protocol*" phrase in Appendix A, sections 3.1.4 and 3.1.5 definitions be deleted.

Comment 26: Commenter 17197 also recommends that the interim NIST traceability protocols be modified to include a recertification interval extension option for the user generators when the Hg CEMS meet a RATA incentive specification. The commenter proposes that the final NIST traceability protocols contain a RATA performance incentive option that extends the user generators' 8-quarter recertification interval another four quarters if the Hg CEMS successfully passes the annual RATA testing at the following proposed incentive specification:

- 10 percent RA,
- or < 0.8 µg/scm difference, if RM average is ≤ 5.0 µg /scm.

According to the commenter, the proposed <0.8 µg/scm difference is consistent with the linearity and integrity check requirements. It is the commenter's view that the user generators should retain their NIST certification as long as the Hg CEMS is able to achieve the alternate RATA incentive performance specification and other periodic QA/QC requirements (i.e., daily calibration, weekly integrity, quarterly linearity). The commenter asserts that if the Hg CEMS cannot achieve the RATA incentive specification, the owner/operator should have a 60-day grace period to recertify the user generators. The commenter supports a 60-day grace period due the complexity of the user generator recertification process.

Response to Comments 25 and 26: The EPA disagrees. The interim NIST traceability protocols for elemental and oxidized Hg gas generators represent significant effort on the part of the EPA, the CEMS vendor community, and affected sources to examine the calibration generator traceability issues, and devise an agreed upon approach for addressing those issues. In fact, one part of this collaborative effort between the EPA and its stakeholders focused on the development of an approach to allow the elemental Hg generators to remain 'in the field' for recertification and one of the organizations representing industry demonstrated how it could be effectively accomplished.

5. Monitoring challenges for new unit Hg limits.

Comment 27: Commenter 17622 believes that Hg CEMS are superior to sorbent traps because continuous monitoring is best done with methods that provide "real time" monitoring that can alert operators to changes in conditions that affect emission rates. According to the commenter, sorbent traps, while a valid continuous measurement method for Hg emissions, do not provide adequate response time to be useful for control and achievement of compliance at the new unit limits. The commenter believes that operators will likely target lower emissions levels (e.g., ~50 percent of the limit for a new unit) for their control set points, in order to have sufficient margin to achieve the proposed 30-day rolling average limitation. According to the commenter, as electronic real-time Hg CEMS will likely be used for emissions control, monitoring and reporting, there are a number of prospective hurdles for new units because commercially-available Hg CEMS have not been fully certified at low levels (<1.0 μg/m3) due to the NIST standard at 0.5 μg/m3 only recently being available. Commenter 17622 goes on to state that the EPA NIST protocol for traceability of Hg generators has not been implemented at Hg concentrations <0.5 μg/m3. According to the commenter, more testing, and possibly development and evaluation of commercially-available Hg generators, is needed to ensure that NIST traceability can be demonstrated and that the Hg CEMS enable control methods for units to stay in compliance. The commenter is concerned that the low Hg emissions level required for new units may be lower than the uncertainty of available measurement methods. The commenter states that Sorbent Trap Reference Method 30B requires a fresh look, particularly relative to sampling protocol and lower limits of detection (LLD) to meet and certify the new EGU limits for Hg and that it is unlikely that current electronic Hg CEMS can be confidently or reliably employed for monitoring, control and reporting of prospective new EGUs emissions under the proposed Utility MACT. According to the commenter, there are clearly both challenges and concerns about the traceability of commercially - available Hg CEMS required to effectively administer the proposed existing unit emission limits. The commenter recommends that the EPA develop a strategic initiative with NIST, targeting lower-level Hg (i.e., <0.5 μg/m3) calibration and standards traceability and support for Hg CEMS and sorbent trap methods.

Comment 28: Commenter 17758 states that the proposed new source Hg limit cannot be measured by any current or planned instrument, and even if a new unit could meet the limit, there is no way to assess compliance.

Response to Comments 27 and 28: The final rule provides the option for use of either Hg CEMS or sorbent trap monitoring systems. The EPA believes the record clearly shows these to be proven technologies, each providing certain advantages. For existing and some of the new unit limit standards, the level of the NIST traceable Hg standard is adequate and consistent with existing applications of Hg CEMS. For the lowest new unit standard, the affected facilities may opt to use sorbent trap monitoring systems to comply. As noted in a previous response, there are data in the recent draft report entitled "DETERMINING THE VARIABILITY OF CMMS AT LOW HG LEVELS," that demonstrate reasonable performance of at least one Hg CEMS at Hg levels below 1.0 ug/m3 down to approximately 0.1 ug/m3.

Comment 29: Commenter 17704 supports both the use of Hg CEMS and the alternative use of sorbent traps as proposed. The commenter also supports the proposed use of 30 days worth of valid Hg CEMS data as the initial compliance test.

Response to Comment 29: The EPA acknowledges this support. See further discussion of sorbent trap monitoring option, below.

Comment 30: Several commenters (17758, 17868, 18428) state that the Hg monitoring requirements should be revised because the accuracy of Hg CEMS near the concentration of the proposed existing source limit is questionable, and one commenter states the technology is not viable at the proposed level of the new source limit for the following reasons:

- The high relative uncertainty of NIST-traceable calibration gases and the lack of any NIST-traceable calibration gases corresponding to the proposed emissions standard.
- Persistent issues transporting samples from the stack to the measurement cell.
- The EPA acknowledged unreliability of Hg CEMS at concentrations corresponding to the standard when responding to questions on the EGU ICR; see https://utilitymacticr.rti.org/FAQ/FAQEmissionsTesting.aspx#TEST-002.

Commenter 17758 states that without further investment in developing Hg CEMS technology to address issues with the availability of NIST-traceable calibration gases at the appropriate concentration levels and sample transport, the only viable option for electric utilities for meeting the continuous Hg measurement requirement is to install, certify and operate a Hg sorbent trap-based monitoring system meeting the specifications in PS12B.

Response to Comment 30: See response to Comments 27 and 28 above.

Comment 31: Commenter 17383 states that they installed CEMS in preparation for the implementation of CAMR and discovered that these monitors took significant man-hours to maintain and to insure their accuracy. According to the commenter, the EPA has left the long-term operational problems, including the development of adequate calibrators and calibration gases to industry. The commenter states that with respect to standards for new units, the EPA developed standards for which there are not accurate and reliable monitoring methodologies for demonstrating compliance.

Response to Comment 31: The final rule allows for sources to use Hg CEMS or sorbent monitoring traps at the choice of the source operator. Sorbent trap monitoring has been shown to be highly reliable and accurate for long term monitoring of HG emissions. Those options should provide sources with the flexibility to select and operate the monitoring system that provides effective data collection sufficient to demonstrate compliance. We understand the concern about the technical hurdles with applying new technologies but we disagree that the Hg CEMS technology is not ready for this application. See also the response to Comments 14-17, above and 32-34, below.

6. Sorbent traps.

Comment 32: Commenter 17402 expresses strong support for the use of sorbent traps as the preferred method for Hg monitoring because the commenter's experience has been that CEMS struggle to measure low levels of Hg in the range of 0.10 µg/m3 to 0.50 µg/m3. By contrast, according to the commenter, sorbent traps are demonstrably capable of measuring Hg in that range, and sorbent traps offer a more consistent and accurate means for monitoring compliance. The commenter states that consequently, the EPA should ensure that sorbent traps remain a permissible means of compliance monitoring in the final rule. If the EPA decides to allow only one method of monitoring, the commenter favors the use of sorbent traps because of their heightened accuracy when compared with Hg CEMS. The commenter relays specific experience with both CEMS and sorbent traps that indicates monitoring results with sorbent traps are more reliable. The commenter believes that it would be far more reliable to look to sorbent traps for compliance with the MACT rule for facilities emitting more than 22 pounds per year, and the commenter provides a lengthy list of problems encountered with Hg CEMS deployments and highlights how sorbent traps do not encounter these problems.

Comment 33: Commenter 18023 states that a sorbent trap-based Hg monitoring system is not a realistic option for units using ACI because real-time feedback from the CEMS is needed to adjust the ACI rate, but a sorbent based monitor does not provide real-time feedback. According to the commenter, a dilemma for new units is that it is quite possible that the only mechanism to detect the new source limit will be through sorbent trap systems, but the new source Hg emission limit is so stringent that it will require sorbent injection for control, yet sorbent trap based monitors cannot be used to modulate ACI systems. The commenter states that sorbent trap based Hg monitoring systems would have limited use on any unit unless the compliance averaging time is extended to at least a 90-day block average because if significant amounts of data are lost over the 30-day compliance period, then demonstrating compliance becomes problematic. According to the commenter, sorbent trap based Hg monitoring systems have the potential for losing at least seven days' and as much as fourteen days' worth of data. The commenter states that the potential loss of data out of a 30-day period would be a particular problem for units that must meet the new source limit because the Hg compliance limit is so low for those units.

Comment 34: Commenters 17808 and 18025 support the use of sorbent traps and note that the EPA should not assume that most EGUS have Hg CEMS.

Comment 35: Commenter 18421 strongly supports the EPA's proposal to require the use of CEMS or sorbent traps for Hg as this will ensure affected sources can demonstrate continuous compliance with the proposed Hg emissions standards. According to the commenter, the EPA's assessment that most, if not all, units that would have been subject to the CAMR had purchased an advanced Hg monitoring system like CEMS or sorbent traps is supported by evidence in a report by NESCAUM. The commenter states that according to NESCAUM, Hg CEMS and sorbent traps are currently in use on over 700 coal-fired power plant stacks (over 600 Hg CEMS and nearly 100 sorbent traps) (see NESCAUM, Technologies for Control and Measurement of Mercury Emissions from Coal-Fired Power Plants in the United States: A 2010 Status Report). According to the commenter, the EPA also correctly points out that many states require coal-fired units to install and operate such controls to demonstrate compliance with SIP or consent decrees.

Comment 36: Commenter supports the inclusion of sorbent trap monitoring systems as an appropriate testing method for continuous Hg monitoring. Commenter installed both CEMS and a sorbent trap on Unit 2 at its Spurlock Station in 2008 to compare the operation and maintenance characteristics of the two technologies; operation of the Hg CEMS began in October 2008 and sorbent trap monitoring in

January 2009. The commenter states that it has experienced recurring reliability issues with the Hg CEMS including constant calibration drift issues, sample transport issues, probe convertor failures, Hg analyzer and Hg lamp failures, design issues that result in a time consuming process to diagnose problems, the need for continual recertification of the calibrator and unreliable operation due to mechanical breakdowns. The commenter's experience with a Hg sorbent trap monitoring system has been positive due to a number of strengths in the system including reliable design with no sample transport issues (the sample is collected at the end of the probe in the traps), the system is simple, problems are diagnosed easily and quickly, the system is appropriate for wet stacks and the system provides accurate Hg data.

Response to Comments 32 - 36: The final rule includes the option of using sorbent trap technology as well as Hg CEMS for monitoring compliance with the Hg standard. For the ACI control rate issue raised by one commenter, a source would be free to use a Hg CEMS for control operations and use the sorbent trap monitoring for compliance if it feels that such operational data is sufficiently critical to its control operations. The addition of backup monitoring provides a further option for addressing the concerns over data loss mentioned by the commenter. The EPA disagrees that the sorbent trap method cannot work on a continuous basis at the emission limit levels in the final rule. While it is true that the potential exists for increased capture of other stack gas constituents by the sorbent traps during long-term monitoring, PS12B addresses this situation. As a result, achieving the monitoring method's measurement performance requirements ensures data of known and acceptable quality. The EPA disagrees that a systematic error exists between the Hg CEMS and sorbent trap technology. In fact, the data from the EERC study definitively show that the agreement between the sorbent trap technology and Hg CEMS at these low levels is significantly better than that required by the relative accuracy specifications in PS 12A, which are consistent with those in the final rule. Also, with respect to PS 12B, section 8.3.2, PS 12B is an approved regulatory requirement that has gone through notice and comment rulemaking as an appropriate set of requirements for a sorbent trap monitoring system. The EPA is not revising PS 12B as part of this rulemaking. The requirement to utilize the same type of sorbent material in the sorbent trap monitoring system as will be used in the future for daily operations simply provides for an additional check on the overall system and procedures. If Method 30B is employed as the reference test method to conduct the relative accuracy testing, the tester may choose to use a different sorbent for the Method 30B sampling train to provide additional independence in the measurements. For low level concerns, the EPA disagrees that the sorbent trap reference method (Method 30B) is unsuitable to reliably perform RATA testing on electronic CEMS at low Hg emissions concentrations. Method 30B is a performance-based method that is, in effect, self-validating each time it is applied and the method-specific performance criteria are met. Moreover, recent testing conducted as part of the Utility MACT ICR demonstrated that Hg concentrations well below 0.1 $\mu g/m^3$ (100 ng/m^3) were reliably measured. In addition, RATA requirements for Hg concentrations less than 0.5 $\mu g/m^3$ are a component of Appendix A in the final rule and are known to be consistent with the measurement performance capabilities of Method 30B. For NIST capability issues, see earlier response to Comments 27, 28, and 30.

Comment 37: Commenter 17757 suggests that quarterly performance tests and analyses of sorbent trap monitoring data would be adequate to determine compliance with an annual emission limit.

Response to Comment 37: The EPA disagrees. Monitoring technology adequate to show continuous compliance in accordance with the emission limit exists and is preferable to periodic emissions testing. In other circumstances under the rule, the EPA has allowed for periodic testing, but in the case of Hg, given the importance of this HAP from this sector and the availability of appropriate monitoring options, the EPA reaffirms the proposal and has retained the continuous Hg monitoring provisions in the final rule.

Comment 38: Commenter 17775 supports use of sorbent trap monitoring systems and reliance on PS 12B, subject to the following comments. According to the commenter:

1. First, the EPA should explicitly provide an option for use of backup monitoring systems to allow sources to plan for the possibility of significant monitoring system failures where it is economical to do so.
2. Second, the EPA should provide a low emitter "breakthrough" specification in PS 12B and in 40 CFR Part 60, Appendix A, Method 30B. According to the commenter, the current performance specification for Method 30B allows for 10 percent breakthrough for effluent concentrations above 1 μg/m3 and 20 percent for concentrations below 1 μg/m3, and as the actual effluent Hg concentration approaches zero, this specification becomes virtually impossible to meet. The commenter asserts that to compound the problem, PS 12B contains a breakthrough specification of 5 percent at all concentrations. The commenter states that during testing for the 2010 ICR, RMB Consulting & Research, Inc. identified this issue during testing at several plants with very low Hg emissions and submitted a proposal to the EPA supporting use of an alternative specification at low concentrations (*see* W. Roberson, RMB Consulting & Research, Inc., "Proposed Alternative Performance Specifications for Method 30B" (June 14, 2010) (see (Attachment 10))). According to the commenter, in the proposal, RMB illustrates with Method 30B data how failure of the specifications is simply a matter of mathematics, because percent-based specifications lose meaning as results approach zero, and RMB recommended that the EPA provide the following alternative performance specifications for breakthrough: A) For concentrations < 0.5μg/m3 but > 0.1 μg/m3, the alternative breakthrough criteria could be < 50 percent of section 1 Hg mass; B) For concentrations < 0.1μg/m3, there would be no breakthrough criteria and the validity of the samples would rest on all other performance specifications being met.

According to the commenter, in response, the EPA staff indicated that, for the purposes of the 2010 ICR testing, and for stack concentrations less than or equal to 0.5 μg/m3, EGUs could consider Method 30B data valid as long as it meets all other QA/QC criteria, even if it does not meet the section 2 breakthrough criteria of Table 9-1 of Method 30B but that the EPA indicated that approval of the exception for the use of Method 30B when conducing RATAs or compliance tests would require additional discussion within the agency. Commenter believes that a number of units being retrofitted with baghouses and scrubbers may achieve Hg emissions levels below 0.5 μg/m3. According to the commenter, in order for sorbent trap monitoring systems to be available as an option, an alternative breakthrough specification is needed in PS 12B. The commenter states that a consistent achievable alternative specification also should be provided in Method 30B, and commenter requests that the EPA promulgate those revisions concurrent with finalization of subpart UUUUU, or complete a rulemaking to revise PS 12B and Method 30B well in advance of the subpart UUUUU compliance deadline.

Response to Comment 38: See the responses to Comment 7, above.

Comment 39: Comment 18449 states the continuous sorbent trap method has not been tested or validated at the very low levels being proposed. According to the commenter, although they use essentially the same method and technology, continuous sorbent tube measurements are even more challenging than sorbent tube reference method measurements. The commenter states that cartridges will be exposed continuously for (typically) 1 or 2 weeks, resulting in massive buildup of other stack contaminants as compared to the short term (2 to 4 hour) exposure period of reference cartridges. According to the commenter, the high levels of potential interferents that are co-eluted when the cartridge is heated will challenge the performance of the analytical instrumentation.

Commenter 18449 notes that a recent EERC study had what are probably the best possible sorbent trap results. The commenter states that EERC took extraordinary care in running the samples, and the manufacturer of the analyzer, Ohio Lumex, provided considerable support throughout the study. The commenter states that agreement between the Tekran CEMS and the sorbent traps was very good, with virtually no zero offset and a R2 value of 0.990. The commenter states that even under these best possible conditions, there was a systematic 11 percent difference in sensitivity between the Tekran CEM which used a NIST traceable elemental gas generator for calibration, and the sorbent traps, which used a NIST traceable liquid solution for calibration. The commenter questions which was correct.

Commenter 18449 states that PS 12B is mentioned as the standard for continuous sorbent Hg monitoring systems. The commenter provides that Section 8.3.2 under RATA testing, states that "The type sorbent material used in the traps must be the same as that used for the daily operation of the monitoring system." According to the commenter, the purpose of a RATA is to provide an independent test of the validity of the continuous monitoring system's results, and if different sorbent types yield different results, this is an indication of a severe problem somewhere. According to the commenter, it may be desirable, from a user point of view, to use the same sorbent, but the commenter does not believe it should be a requirement to do so.

Commenter 18449 provides the following comments with respect to the sorbent tube provisions:

1. If Hg levels in the low ng/m3 range are set as the MACT limits, they would have to be RATA'd on a regular basis. Commenter does not believe that the sorbent tube reference method has been sufficiently validated at these low levels to establish that it could be used to reliably perform RATA testing on electronic CEMS.
2. NIST is incapable of measuring or certifying Hg concentrations in the low ng/m3 range. According to the commenter, after 5 years of effort, the lowest point that NIST can certify is 0.5 µg/m3 and even this point can only be certified to an uncertainty of 6.1 percent. The commenter notes that this level of uncertainty applies to the NIST calibrator only and that vendor and user calibrators would have still higher uncertainties. Absent major developments, the commenter does not believe the NIST traceable gases be available to validate low ng/m3 measurements.

Response to Comment 39: See response to Comments 32-36 above.

7. Provisions for Hg CEMS on bypass stacks.

Comment 40: Commenter 18023 states that the final rule should clarify the provisions for units with a main stack and a bypass stack regarding use of the maximum potential concentration (MPC) for each hour in which the bypass stack is used. According to the commenter, if this approach is used, the EPA needs to clarify what value is used when Hg CEMS installed on a bypass stack measures a number higher than the MPC. The commenter also asserts that the EPA should specify that when multiple units are controlled by the same device and less than all of those units are being bypassed only the MPC for the units being bypassed, should be reported. According to the commenter, MPC should not be used for any of this since the MPC approach is only used for emission trading programs; a lower confidence interval type of value should be used instead for conditions where a bypass stack is not monitored.

Comment 41: Commenter 17774 states that one difference between section 63.10010(a) and Appendix A section 2 is the provision of an option for use of an assumed value during use of a bypass stack. The commenter states that Appendix A section 2.4.2 provides for use of the "maximum potential concentration" of Hg in lieu of installing an Hg CEMS or sorbent trap system on a bypass stack.

According to the commenter, installation of CEMS on a bypass stack can be problematic from a number of perspectives. According to the commenter, in addition to the costs of the additional monitoring system, bypass stacks will not be used with sufficient frequency to perform those periodic QA tests that require unit operation (e.g., RATAs and linearity checks). The commenter asserts that correlation of a PM CEMS on a bypass stack would be nearly impossible to accomplish without significant operation with bypass (since PS 11 requires a minimum of 15 runs).

Response to Comments 40 - 41: The EPA agrees with one of the commenters that the MPC approach for bypass stacks is more suited to an emissions trading program. Rather than require the use of the MPC to estimate emissions from the bypass stack, the final rule now requires use of one of two options: (1) direct monitoring of both the main stack and the bypass stack for Hg or (2) counting of bypass hours as hours of deviation from the Hg monitoring requirements. The EGU owner or operator remains subject to the 30 boiler operating day rolling average during bypass operations. In addition, the final rule no longer requires correlation of a PM CEMS according to PS 11. The monitor will be used as a PM CPMS, although the final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

8. Provisions for bias adjustments.

Comment 42: Commenter 18023 states that the final rule should not require the bias test and bias adjustment for Hg CEMS as proposed in section 4.1.1.5.3 because the Hg CEMS by nature exhibit drift in both the positive and negative directions depending on the cause of the drift which is best corrected through normal quality assurance activities, and basing adjustment of the hourly averages on a one-time per year test would adversely affect data accuracy. According to the commenter, if a bias test were required, it should quantify bias in either direction and allow for adjustment in either direction. The commenter states that when stack gas flow is used for the mass calculations then non-bias adjusted flow values should be used for that purpose.

Comment 43: Commenter 17805 agrees with the EPA that application of a bias adjustment for Hg emissions is not necessary. It is the commenter's understanding that a bias adjustment, as used for SO_2 emissions in the Acid Rain Program, was primarily intended to assist with ensuring emissions were adjusted properly for cap and trade of emissions. According to the commenter, since Hg will not be traded, the bias adjustment is not necessary.

Response to Comments 42 and 43: No bias adjustment or bias test is required under the final rule.

9. General concerns.

Comment 44: Commenter 17621 states that the EERC of North Dakota conducted a study to investigate the low-level measurement capabilities and variability of CMMs from Thermo Scientific and Tekran, with support from EPRI, DOE, and the Illinois Clean Coal Institute. The commenter states that EPRI reported that the quantification level of the Tekran system was 0.1 micrograms per normal cubic meter ($\mu g/Nm^3$), compared to 0.4 $\mu g/Nm^3$ for the Thermo Scientific system (EPRI, 2010b) and that these concentrations are equivalent to about 0.1–0.4 lb/TBtu. The commenter states that Method 30B was used as the basis for comparison, with extended sampling times used to reach the low levels of Hg. The commenter asserts that based on this study, CMMs from both vendors can measure Hg accurately at the proposed MACT limit for existing coal-fired EGUs but that CMM would neither be able to measure Hg accurately at the revised MACT limit for new coal-fired EGUs greater than or equal to 8,300 Btu/lb or at the proposed limits for either existing or new liquid oil-fired EGUs.

Response to Comment 44: The final rule provides the option for use of either Hg CEMS or sorbent trap monitoring systems. The EPA believes the record clearly shows these to be proven technologies, each providing certain advantages. For existing and some of the new unit limit standards, the level of the NIST traceable Hg standard is adequate and consistent with existing applications of Hg CEMS. For the lowest new unit standard, the affected facilities may opt to use sorbent trap monitoring systems to comply. As noted in a previous response above, there are data in the recent draft report entitled "DETERMINING THE VARIABILITY OF CMMS AT LOW HG LEVELS", that demonstrate reasonable performance of at least one Hg CEMS at Hg levels below 1.0 ug/m3 down to approximately 0.1 ug/m3.

Comment 45: Commenter 17747 states that the cycle time test unfairly excludes monitoring technologies that can provide accurate mercury measurement. According to the commenter, Xact (the commenter's proprietary testing technology) has demonstrated its ability to measure Hg accurately on several different source types including coal-fired power plants. Commenter provided results of studies on 585 MW coal fired electric generating facility equipped with ESP controls and located in the northwestern United States. According to the commenter, these results demonstrated the Xact had a relative accuracy of 3.53 percent, significantly better than the required 20 percent (figure 1 in comment document). According to the commenter, Xact is designed to measure Hg by sampling stack effluent nearly continuously, excluding only the time required for the tape to advance from the sampling area to the analysis area (~ 20 sec). The sample is typically gathered for 15 minutes and then analyzed for 15 minutes to achieve detection limits that are appropriate for coal fired power plants, and this means that concentration data is reported about 30 minutes after starting to gather the sample. According to the commenter, the proposed cycle time would preclude the use of Xact. The commenter states that the key issues are whether the instrument can measure Hg accurately and precisely and whether emissions are nearly constantly monitored and that provided the technology can demonstrate these things, response or cycle time is irrelevant.

The commenter notes that the current cycle time requirements are apparently based on what atomic fluorescence-based instrumentation can do. Although this technology can deliver mercury concentration data more quickly than XRF based technology, it can only measure mercury. The commenter notes that the Xact, on the other hand, can measure mercury as well as several other metal hazardous air pollutants (HAP) including (antimony, arsenic, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium). According to the commenter, this type of data is currently not available using any other instrument, and it is unlikely that it could ever be obtained from any atomic fluorescence based instrument.

The commenter notes that the proposed Hg monitoring performance specifications are inconsistent with those already promulgated under PS 12A. According to the commenter, this performance specification does not require a cycle time test, which indicates that EPA does not view a cycle time test as critical to the performance requirements of a Hg CEMS. The commenter notes that the reason the EPA did give for not using the PS 12A requirements is to "simplify compliance with the proposed rule by harmonizing its monitoring and reporting requirements, to the extent possible with 40 CFR Part 75." According to the commenter, this would include eliminating semiannual hard copy reporting of deviations along with data assessment reports required by 40 CFR Part 60, where PS 12A resides, and cycle time does not play any role in these more onerous reporting requirements. The commenter notes that the proposed EGU MACT does allow for the use of PS 12B (sorbent trap monitoring) and that in this case facilities may sample for up to 14 days before ending the traps to a lab for Hg analysis. According to the commenter, this would potentially allow 4-6 weeks to elapse before Hg data would be generated and reported, and it clearly does not make any sense to allow up to 6 weeks or more for data to be reported under one method of monitoring (sorbent traps) but require data every 15 minutes under another method (CEMS). Finally, the commenter notes that because Hg health effects are chronic there is no health benefit associated with 15-minute cycle times.

Response to Comment 45: The EPA agrees that the cycle time test requirements may be overly rigid for integrated batch sampling-based Hg monitoring technologies, and we have made revisions to the final rule to accommodate these technologies while still acquiring monitoring data at least once every 15-minutes consistent with our practice for CEMS.

Comment 46: Commenter 18428 states that an alternative to using CEMS for compliance, the EPA should allow fuel sampling and analysis for Hg determining Hg emissions from coal-fired units, particularly those with low coal Hg content. According to the commenter, this would be consistent with the fuel sampling option for oil-fired units under the proposed rule, as well as the similar option contained in the Industrial Boiler MACT rule.

Response to Comment 46: The fuel sampling option discussed in the proposed rule is no longer part of the final rule because of technical issues with those proposed requirements. The final rule retains the proposed approach for Hg monitoring, requiring either a CEMS or sorbent trap monitoring system, or LEE testing for existing units with very low emissions.

Comment 47: Commenters 17724 and 17876 state that the CEMS the facility installed in preparation to CAMR have significant reliability and operational issues (Hg, PM, HCl). Commenters 17724 and 17876 state that the EPA has left the long-term operational problems such as calibration gases to industry and there are not accurate and reliable monitoring methodologies for demonstrating. Commenters 17724 and 17876 state the EPA purports to provide compliance flexibility while in reality there is very little flexibility in light of the problematic and unproven nature of these monitoring technologies.

Commenter 17736 states the EPA cannot rely on unproven HCl CEMS, that HCl CEMS are not commercially available to measure HCl emissions from coal-fired EGUs, and no HCl CEMS were used to collect the data the EPA used to establish the HCl standard.

Response to Comment 47: The agency disagrees with the commenters. As mentioned elsewhere, the agency finds that the operation and maintenance issues for the CEMS mentioned are no different than for other CEMS now in wide use and acceptance by the industry. The agency is aware that the calibration gas issue is to be rectified well in advance of the rule’s compliance date. The agency notes that the rule is quite flexible with respect to compliance demonstration, containing numerous choices for compliance, including the use of emissions testing alternatives for those EGU owners or operators who remain concerned over use of CEMS or PM CPMS. The agency notes that FTIR CEMS exist now and can be used to measure HCl emissions continuously, that the HCl emissions limit was developed from emissions testing and has been adjusted to be appropriate for measurement with HCl CEMS, and that emissions testing options to demonstrate compliance exist for those EGU owners or operators who choose not to use CEMS.

5A06a - Testing/Monitoring: Application of Hg CEMS (Appendix A)

Commenters: 17725, 17770, 17795, 17796, 17800, 17820, 17821, 17881, 17886, 18449, 19114, 19121, 19122, 18023

1. Rounding issues.

Comment 1: Commenter 17881 states that section 7.1.8.2 requires Hg mass emissions be reported as pounds, to three decimal places. According to the commenter, this is not sufficient precision to allow a meaningful comparison to the Hg emission limit for new coal-fired units (coal > 8,300 Btu/lb). The commenter states that the Hg emission limit for such units is 0.0002 lb/GWh based upon the EPA's 05/18/2011 revised MACT floor analysis memorandum and that units as small as 25 MWe are affected by the proposed EGU MACT, so compliance with the aforementioned new unit Hg limit would equate to a mass emission rate of 0.000005 lb/hr. The commenter asserts that after rounding the preceding mass emission rate, as pounds, to three decimal places, it will become zero, and that \anything as high as 0.0004 lb/hr will round to zero. Thus, according to the commenter, a unit as small as 25 MWe could emit up to approximately 80 times the allowed Hg emission rate and yet still show compliance due to the specified rounding precision in Appendix A.

Comment 2: Commenter 17881 states that section 7.1.9 indiscriminately requires that the Hg emission rate records, in units of lb/TBtu or lb/GWh, be rounded to three decimal places. According to the commenter, this requirement makes little sense, as all lb/TBtu emission limits in the proposed rule are expressed to one decimal place, and several of the lb/GWh Hg emission limits are expressed to beyond three decimal places. The commenter states that as noted in relation to section 7.1.8.2, the Hg emission limit for new coal (> 8,300 Btu/lb) fired units is 0.0002 lb/GWh. According to the commenter, rounding all calculated Hg emission rates to three decimal places would prohibit a meaningful compliance determination with the preceding emission limit (i.e., an actual emission rate of 0.0004 lb/GWh, which is twice the emission limit, would round to 0.000 lb/GWh, which is compliance with the emission limit).

Comment 3: Commenter 18449 states that under "Calculation of Mercury Mass Emissions" on page 25145 the rule requires that reported concentration averages for both CEMS and sorbent methods be rounded, to the nearest tenth but that it is not clear how this would work with proposed MACT limits of 0.02 µg/m3, or how accurate 30-day rolling averages could be calculated with sources in the sub-microgram range. The commenter states that it has existing customers that have short term concentrations of 0.03 to 0.5 µg/m3, which have been verified by RATA testing. According to the commenter, hourly averages should be rounded to two or three significant figures, not tenths. The commenter believes that reporting to more decimal points has no downside provided that violations are defined as significant exceedances of the limit and that more accurate reporting would also give customers due credit if they had low level emissions and had invested in the technology able to report them.

Response to Comments 1 - 3: The EPA agrees with the commenters regarding the precision of the Hg concentration values and the Hg emission rates. The final rule requires the hourly Hg concentrations and emission rates to be reported to three significant figures, rather than specifying a particular number of decimal places. The 30-day average Hg emission rates are to be rounded to two significant figures (i.e., the same precision as all of the Hg emission limits). We believe that these changes address the concerns of the commenters.

2. Calculating Hg emission rate.

Comment 4: Commenter 17881 recommends the following items related to calculating the Hg emission rate:

1. Section 6.2.1.1 should be revised to explicitly note that fuel factors from 40 CFR Part 75, App. F, section 3.3.5 or those derived consistent with the procedures in section 3.3.6 may also be used for these calculations for calculating the Hg emission rate in units of lb/TBtu, According to the commenter, this change is necessary due to the fact that Method 19 does not contain fuel factors for subbituminous coals, petroleum coke or tire-derived fuels, and the provisions of section 12.3.2 of Method 19 would therefore require fuel sampling and analysis in order to determine site-specific fuel factors. The commenter states that the preceding would represent an unnecessary burden in light of the EPA having already established fuel factors for these fuels under 40 CFR Part 75.
2. Sections 6.2.1.2 and 6.2.2.2 of Appendix A relate to the calculation of Hg emission rates in units of the applicable standard (i.e., lb/TBtu of lb/GWh). According to the commenter, , this section should also describe the diluent capping procedure for start-up and shutdown, as allowed in section 63.10005(l). The commenter states that without reference to the preceding diluent capping provisions, these sections would appear to always require the use of the actual measured diluent gas concentration (in the context of section 6.2.1.2) or measured electrical load for the hour (in the context of section 6.2.2.2).
3. Section 6.2.2.2 should specify the use of the gross electrical output (consistent with the gross output definition in section 63.10042) in order to eliminate any possible confusion as to the basis of the MWh values to be used in the calculations (i.e., gross or net).
4. The formulas for calculation of the lb/GWh Hg emission rate (i.e., A-2, A-3 and A-4) all include an operating time component (th). It is not necessary to convert the Hg mass emission rate or the average electrical load to a total integrated pound or load value for each clock hour. Rather, the Hg mass emission rate and average electrical load can be used to directly calculate the Hg emission rate in units of lb/GWh. (commenter references a formula “Consider the following substitution of Equation A-2 into the term Mh in Equation A-4, and note that the term th cancels out, as it appears in both the numerator and denominator:”)

Response to Comment 4: The EPA agrees with items 1 through 4 in this comment and has made corresponding changes in the final rule.

3. Grace period.

Comment 5: Several commenters (17770, 17820, 17886) note that part 75 has a grace period for system integrity checks and recommend the same. Commenter 17820 states that the system integrity test is likely to be one of the most challenging tests and if the test cannot be automated EGUs will need to monitor operating hours to determine when a test will be due, and ensure that a qualified technician is available to generate the oxidized Hg and ensure that the test is conducted properly. According to the commenter, if the unit is not fully base-loaded, this will be difficult; most EGUs do not have technicians available to perform routine tests on nights and weekends, and even if the test is scheduled to be performed on time, issues with monitoring system breakdowns and the time necessary to complete maintenance could also result in late tests. Commenter 17820 recommends an operating hour grace period of at least 72 unit operating hours before data are invalidated, which would provide an EGU time to schedule and perform a test if one were triggered.

Response to Comment 5: For concerns raised with the system integrity check requirement, the final rule retains the weekly system integrity check requirement, without a grace period. However, to add flexibility, the required frequency of the test has been changed from once every 168 operating hours to once every 7 operating days. Operating days are much easier to track than operating hours. The test can be done at any time during the 7th operating day, rather than requiring it to be done at a certain hour. We believe that this added flexibility will allow utilities to schedule the test in accordance with the technician's work schedule.

4. Recordkeeping and reporting under Section 7 of Appendix A.

Comment 6: Commenter 17881 requests clarification of the recordkeeping and reporting provisions contained in appendix A, section 7:

1. The commenter states that it is unclear whether the requirements are meant to apply to the Hg CEMS and sorbent trap monitoring systems, or all monitoring systems used to demonstrate compliance
2. The commenter states that Section 7.1 requires that all measurements, data, et cetera, must be maintained for a period of 5 years from the date of the record. According to the commenter, since many of the auxiliary monitoring systems employed under Appendix A will also likely be subject to 40 CFR Part 75, the EPA should harmonize the data retention requirements with those found in 40 CFR 75.57(a), which requires that data be maintained for a period of at least 3 years from the date of each record. According to the commenter, having two different retention schedules for the same data elements (i.e., flow rate data, diluent data, etc.) will simply lead to confusion and potential non-compliance, especially in cases where a facility currently has well established procedures to purge various Part 75 data elements after the required 3 year period.
3. The commenter states that the EPA should clarify that none of the provisions in section 7.1.1 and related sub-sections apply to those auxiliary monitoring systems which are subject to 40 CFR Part 75, as many (if not all) of these requirements are duplicative of those that already exist within 40 CFR Part 75.
4. The commenter questions the rationale for some of the requirements to be reported in the context of Hg emissions monitoring. The commenter provides an example of megawatt ratings under section 7.1.1.2.1; according to the commenter, the EPA makes the presumption that all individual units have a defined megawatt output, which is not correct. According to the commenter, In those cases where multiple units share a common steam extraction turbine and electrical generator, steam output is often the basis for the individual unit ratings, and this approach is clearly allowed under 40 CFR Part 75 (refer to section 75.53(e)(1)(i)(I)). The commenter also states that the basis for any load rating must be specified (i.e., net or gross).
5. The commenter notes that under section 7.1.1.2.1 the identification of controls should be specific to those types of controls which have relevance under 40 CFR part 63, subpart UUUUU and that these would include acid gas controls, PM controls and Hg specific controls. Thecommetner questions how the collection of information on NO_X controls, for example, would be relevant under the proposed EGU MACT.
6. According to the commenter, formulas used to calculate emissions and heat input under section 7.1.1.2.1 only need formulas which are specific to the determination of the Hg emission rate in units of the applicable standard. The commenter also states that the calculation of heat input is not required to support the Hg emission rate determination, and this reference should be removed from the rule.
7. The commenter states that Section 7.1.2 relates to various operating parameter records which must be maintained "to the extent that these data are needed to convert Hg concentration data to the units of the emission standard". According to the commenter, rather than leaving it to the discretion of the regulated entity to determine whether certain data elements are needed, the EPA should clearly specify which data elements are necessary for each of the Hg emission limit forms (i.e., lb/TBtu and lb/GWhr).

8. The commenter states that Section 7.1.5.2.5 also requires the reporting of hourly PMA, which is not appropriate when missing data substitution is being prohibited.

Response to Comment 6: For item 1, appendix A applies to any Hg CEMS or sorbent trap monitoring system, as well as any other auxiliary monitoring required to report emissions in terms of the standard. As suggested in item 3 of this comment, the final rule clarifies that where such auxiliary systems are used, the recordkeeping provisions of part 75 generally apply to those systems. As in the proposal, one exception to that rule is that, consistent with the general recordkeeping provisions under the Part 63 NESHAP program, records used to demonstrate compliance with this rule must be kept for 5 years. For items 4 through 6, revisions in the final rule directly address these concerns and streamline the specific records that apply. For Item 7, the EPA has left the "as applicable" language as proposed; the reporting system will provide for capturing the correct information based on each emission limit. For item 8, just because the rule does not specify a minimum data availability requirement, does not mean that information on percent monitor availability is unnecessary. This information will be used to ensure that sources continue to operate and maintain their monitoring systems in accordance with the requirements of section 63.10020(b) and the general monitoring operation provisions that apply across part 63.

5. Recommendations - Appendix A.

Comment 7: Commenter 17725 recommends that the EPA add a subsection to Appendix A section 7.1.5.2.3 that clearly states that 40 CFR Part 75 data substitution procedures and bias adjustment factors are not to be used with the hourly average volumetric flow rate used by a sorbent trap monitoring system.

Commenter 17795 recommends the following changes to Appendix A:

1. The commenter states that Section 3.1.12 should be rewritten to allow the use of the closest upscale gas from actual stack concentrations and that currently, the proposal suggests implementing a Hg monitor span of 0-10 ug/m3. According to the commenter, for existing units > 8300 Btu/lb to demonstrate compliance with the proposed limits, Hg concentrations would need to be less than 1.2 ug/m3, and therefore the low level calibration gas would be closer to actual emissions and should be used as the daily calibration standard (20–30 percent of span value).
2. The commenter recommends quarterly, instead of weekly, oxidized Hg (Hg+2) converter checks. According to the commenter, NIST-traceable Hg+2 in the Tekran Hg monitoring systems is currently limited to ~2.5 ug/m3, but Hg+2 will be < 0.5 ug/m3 after controls to achieve compliance with the proposed standards. According to the commenter, quarterly checks will be more than sufficient at these levels. The commenter states that a weekly requirement was understandable for the trading program that would have been adopted for the CAMR where Hg+2 could exist in the gas stream of units purchasing of Hg allowances, but for this program Hg+2 won't be quantifiable for units in the > 8300 Btu/lb category. According to the commenter, calibrating a system at more than 5 times the measurable concentration would produce accuracy problems and filter contamination if conducted weekly at these levels.

Response to Comment 7: The EPA sees no need to add a subsection to section 7.1.5.2.3 of Appendix A as section 4.1.2.4 of Appendix A clearly states that bias adjustment is not required for sorbent trap monitoring system data. The EPA does not believe that allowing a low-level gas to be used for daily calibrations is necessary. Appendix A provides sufficient flexibility in setting the Hg CEMS span value and selecting calibration gases. The span value is set starting with the Hg concentration ($\mu g/m^3$) corresponding to twice the level of the standard. This value is then rounded upward, either to the next highest integer, the next highest multiple of 5 μg/m^3, or to the next highest multiple of 10 μg/m^3. For instance, if the level of the standard corresponds to a concentration of 1.2 μg/m^3, as suggested by the commenter, the span value could either be set at either 3 μg/m^3, 5 μg/m^3, or 10 μg/m^3. If it is set at 3 μg/m^3, a mid-level calibration gas with a concentration of 50 to 60% of the span value (i.e., 1.5 to 1.8 μg/m^3-- which is in close proximity to the level of the standard) could be used for daily calibrations. We believe this addresses the commenter's concerns.

Regarding the system integrity check, the EPA does not agree with the commenter that a quarterly test frequency is sufficient. To obtain accurate data with a Hg CEMS that has a converter, you must ensure that the converter is working properly. The system integrity check provides that assurance. Therefore, it is not appropriate to allow long time intervals between converter checks. If a quarterly test frequency were implemented, there could be more than five months between successive system integrity checks, e.g., if the test is done in early January (1st quarter) and the next one is not done until late June (2nd quarter). This level of quality-assurance for monitoring a HAP such as Hg is unacceptable.

Comment 8: Commenter 17796 states that the QA procedures for Hg CEMS outlined in CAMR and duplicated in Appendix A of the proposal are appropriate for determining that the unit is providing accurate results and should not be changed because now compliance is based upon an emission limit and not a yearly mass for trading purposes in CAMR.

Response to Comment 8: While the EPA agrees in many respects, we have made certain changes to the CAMR-based Hg monitoring procedures as appropriate, such as not using bias adjustment factors and not relying on data substitution practices.

Comment 9: Commenter 18023 states that under section 3.2.3.3, to provide for efficiency, the option should be provided to allow the use of monitors already installed and certified under part 60 or 75 without any additional requirements.

Response to Comment 9: The commenter is referring to the additional monitoring systems described in sections 3.2.3.1 and 3.2.3.2 (not section 3.2.3.3, which addresses monitor span and range). These additional monitors (i.e., diluent gas, flow rate, and moisture) are needed to convert Hg concentrations to the units of the emission standards. The final rule mandates that all of these monitoring systems be installed, certified, operated, and maintained according to 40 CFR Part 75 (see §§63.10010(b) through (d)), and that the data from these monitoring systems be reported using the ECMPS Client Tool. Nearly all coal-fired utilities already have these monitors in place to meet Acid Rain Program requirements. The final rule makes it clear that no additional certification testing is required under Subpart UUUUU for previously-certified Part 75 systems that are continuing to meet Part 75 QA requirements (see §63.10005(d)). Note, however, that the use of Part 60 monitors is not allowed---these monitors must either be replaced or upgraded to meet Part 75 requirements.

Comment 10: Commenter 17820 generally supports the EPA's attempt to provide consistency between this proposal and Part 75 but notes that not all of the part 75 requirements are necessary in this context. Some of these concerns include:

1. Commenters 17820 and 17800 note that while the EPA proposes ongoing QA requirements for Hg CEMS in Appendix A, the rule proposes in section 63.10021(1)(14) to require compliance with quarterly accuracy determinations and calibration drift tests in accordance with Part 60, Appendix F, Procedure 5. According to the commenters, the quarterly and daily requirements in Procedure 5 are duplicative of and conflict with some of the proposed requirements in Appendix A, and use of

Procedure 5 is inconsistent with the EPA's preamble statement that it considered and rejected using Procedure 5.

2. The commenter opines that two provisions from Part 75 that could help improve data availability are the provisions for use of back up monitoring systems and the provisions for use of conditional data validation. According to the commenter, these options have been used under Part 75 for years without any reduction in data quality, and the EPA should include provisions in Appendix A to allow use of similar procedures.
3. The commenter opines that the EPA should include back up and like-kind replacement monitoring system options similar to Part 75 in Appendix A. According to the commenter, including specific provisions will avoid the need for future guidance and/or unit-specific petitions if cases arise where a backup or replacement is needed.
4. The commenter states that Section 75.20(b)(3)(ii) allows sources that have made a change to a monitoring system that requires additional testing (e.g., repairs, replacements, adjustments, linearization, reprogramming, relocation, etc.) to conditionally validate data prior to completion of all required tests by performing a successful "probationary calibration error test." According to the commenter, this provision has been crucial to maintaining good data availability under Part 75, by avoiding invalidating data after a monitoring system has been confirmed to be operating properly but before all of the required confirming tests can be scheduling and completed.

Response to Comment 10: The final rule removes the references to Procedure 5 and adopts the part 75 options discussed in items 2 through 4 of this comment.

Comment 11: Commenters 19121 and 19122 support the monitoring requirements for Hg outside of part 75. However, the commenters recommend the following changes to Appendix A:

1. Commenters recommend amending the minimum requirement in section 3.1.16 (RATA) of nine valid test runs be reduced to a minimum of three runs (six samples) to show compliance. Commenters also recommend that a similar reduction in paired runs apply to certification and recertification events in other applicable Part 60 rules.

2. With respect to alternative 2 for accounting for gas moisture content under section 3.2.3.1 commenters believe that the moisture value need not be limited to the most recent Hg emissions test. Commenters recommend that any test event that requires a Method 4 analysis to be performed such as a CEMS RATA or Method 4 particulate test result be a valid representation of the stack moisture condition.

3. Commenters recommend that "significant percentage" language in section 5.1.5 be more clearly defined. The commenters believe that it is likely infeasible to perform a diagnostic linearity check within 168 hours of a span change as it would require that the Hg calibration gas generators' output values be adjusted by the manufacturer to the new linearity requirements which require new NIST certification of the generators. Thus, according to the commenters, the time needed to ship the calibration gas generators to the manufacturer, modify and recertify the generators can take longer than 168 hours. Commenter 19121 recommends that owners/operators have 30 operating days to perform a diagnostic linearity check after change of span value.

4. Commenters recommend that if CO_2 and flow data is available, the procedures in 40 CFR Part 75 be used to calculate the Hg emission rate instead of the current section 6.1.3 that states "for any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used, in the emissions calculation, or moisture, as applicable, do not calculate the Hg emission rate for that hour."

5. Commenters recommend the EPA incorporate by reference parts of Part 75 that are used to determine Hg emission rate calculations in section 7.

Response to Comment 11: Regarding changes 1) through 5) suggested by the commenters:

1. At this time, the EPA has no intention of reducing the minimum number of test runs for the RATA of a Hg CEMS from nine to three, as recommended by the commenters. The nine run RATA is a well-established procedure that provides a robust statistical basis for determining the accuracy of a CEMS, and is familiar to, and widely accepted by, the regulated community and source testers. The commenters provided no data to support their claim that three runs (as opposed to nine) are sufficient to assess relative accuracy. Without such demonstration data, a change in the RATA procedures is unwarranted. Further, the commenters' broad recommendation to extend the proposed reduction in the number of paired runs to "certification and recertification events in other applicable Part 60 rules" is beyond the scope of this rulemaking.

2. Sections 63.10010(b) through (d) of the final rule specifies that all of the additional monitors needed to convert Hg concentrations to units of the emission standard must meet the requirements of 40 CFR Part 75. To account for stack gas moisture content, Part 75 provides three possible compliance options: (a) install and certify a continuous moisture monitoring system; (b) use a fuel-specific default moisture value from §75.11(b); or (c) petition the Administrator under §75.66 for a site-specific default moisture value. Under option (c), the proposed default value could be based on Method 4 data collected either during historical stack tests or CEMS RATAs.

3. Proposed section 5.1.5 of Appendix A has been renumbered as section 5.1.6 in the final rule, and has been made consistent with sections 2.1.1.5 and 2.1.2.5 of 40 CFR Part 75, Appendix A, regarding span adjustments. The proposed requirement to perform a diagnostic linearity check within 168 operating hours after changing the span of a Hg analyzer has been retained, but a clearly defined window of time in which the span change must be implemented has been added. The owner or operator has up to 90 days after the end of the calendar quarter in which the need for a span change is identified to implement the span adjustment.

4. The EPA has not incorporated the commenter's recommendation. The final rule retains the statement in section 6.1.3 of Appendix A prohibiting calculation of Hg emission rates when valid data for one or more parameters are not available. This is consistent with a long-standing position that compliance with emission rate limits must be based exclusively on actual, measured data---i.e., the use of substitute data is not appropriate for Part 60 programs (for example, see statements to this effect in NSPS Subpart Da). This is in contrast to emissions accounting programs such as the Acid Rain Program, which require pollutant mass emissions to be reported for every unit operating hour, in accordance with 40 CFR Part 75. During monitor outages, Part 75 requires substitute data values to be used in the calculations. Note that even if EPA had decided to allow the use of substitute data during Hg monitor outages, the commenter's suggested calculation approach could not have been implemented, because all of the Hg monitoring provisions of Part 75 have been removed from the rule in response to the vacature of the Clean Air Mercury Rule (CAMR) (see 76 FR 17301, March 28, 2011).

5. The EPA has incorporated the commenter's suggestion to simplify section 7 of Appendix A by referencing relevant sections of Part 75, but only for the additional monitoring systems that are needed to convert Hg concentration to units of the standard (i.e., diluent gas, flow rate, and moisture systems). Similar cross-referencing of Part 75 is not possible for Hg emission rate calculations because, as explained in the previous paragraph, Part 75 no longer includes Hg monitoring provisions.

Comment 12: Commenter 17800 states that the EPA needs to remove the requirement for a NIST traceable oxidized Hg standard from the certification tests (see 86 FR 25034). The commenter is not aware of any oxidized standard for Hg, let alone a "NIST-traceable oxidized Hg standard".

Response to Comment 12: The definition of a "NIST-Traceable Source of Oxidized Hg" in section 3.1.5 of Appendix A refers to a generator that: (a) is capable of providing known concentrations of vapor phase mercuric chloride and (b) meets the performance requirements of the interim version of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators". That traceability protocol was developed with significant input from industry, consultants, and vendors of Hg CEMS. The protocol does not provide NIST traceability through an unbroken chain of comparisons for the oxidized Hg calibration gas, but rather establishes NIST traceability for chemical reagents used to produce the calibration gas (such as $HgCl_2$ solutions or chlorine gas cylinders), and for individual components of the gas generator which measure these reagents in the process of producing the gas, e.g., weighing and mass flow meters. This approach represents the current "state of the art" and has been agreed upon by EPA and industry as an interim methodology. Further research is needed to develop direct NIST traceability for oxidized Hg calibration gas standards.

Comment 13: Commenter 17821 states that section 3.2.1.4.3 proposes to require that the full "range" of the Hg analyzer be capable of measuring the MPC values that are defined in section 3.2.1.4.1. Commenter encourages the EPA to define the MPC value as the "span" and "range" of the Hg CEMS and suggests that this value be used as the basis for determining calibration and linearity gas values and calibration errors. According to the commenter, modern Hg CEMS are based on digital technology and do not have "span ranges" built into the technology like the older analog analyzers of the past. The commenter states that they do have analog outputs that can be scaled such that a zero and full scale value can be defined to match with the 4-20 mA output signal used for data recording, but that this setting is not a span range setting in the analyzer. According to the commenter, modern Hg analyzers have a measurement range that is limited only by the lower and upper detection limits of the measurement sensors within the analyzer. Commenter understands the need to determine the accuracy of an Hg analyzer and the need to determine calibration and linearity errors. However, according to the commenter, defining an arbitrary value for "span" is meaningless to a modern Hg analyzer, and a better method would be to utilize a standard "span" value for all Hg CEMS used in compliance with these proposed rules. (Commenter provides an example**.)**

Comment 14: Commenter 17821 recommends that the EPA define the "range" of the Hg CEMS as a range from zero to the appropriate MPC (see section 3.1.13). According to the commenter, a source would then perform linearity checks "across the range as determined by these rules" instead of across the analyzer's entire measurement capability. The commenter states that modern Hg analyzers have a large measurement range, and the commenter does not believe that EPA intended for sources to test the analyzer across its entire range of measurement but rather across the "span" or full "range" defined for use with compliance of these proposed rules.

Response to Comments 13 - 14: The commenter appears to misunderstand the terms "span" and "range" as they are presented in Appendix A. The purpose of the span value is to determine the appropriate calibration gas concentrations for daily calibrations and linearity checks---these concentrations are all expressed as percentages of the span value. To comply with the stringent Hg emission limits in subpart UUUUU, Hg concentrations must be reduced to very low levels. Section 3.2.1.4.2 of Appendix A requires the span value to be set by multiplying the Hg concentration corresponding to the standard by two, and then rounding off the result appropriately. Flexibility is provided; the span value (in units of $\mu g/m^3$) may be rounded to either the next highest integer, the next highest multiple of 5 μg/m^3, or the next highest multiple of 10 μg/m^3. If better accuracy at the lower end of the scale is desired, rounding off the span value to the next highest integer or multiple of 5 μg/m^3 may be preferable to rounding to the next highest multiple of 10 μg/m^3, because calibration gases closer to the level of the emission standard will be used for daily calibrations and linearity checks (see the response to Comment 7, above). The EPA recognizes that low Hg concentrations are often attainable only by operating wet scrubbers and/or carbon injection systems, and that it is possible for these emission controls to malfunction. During control device malfunctions, Hg concentrations may approach the level of the maximum potential concentration (MPC). Therefore, section 3.2.1.4.3 of Appendix A also requires the Hg analyzer to be capable of reading Hg concentrations as high as the MPC.

Comment 15: Commenter 18023 states that section 3.1.7 requires the span value to be set to approximately twice the concentration corresponding to the emission standard and alternatively rounding the span value to the next highest interval of 10. According to the commenter, based on the emission limit stated in the current draft rule, this would restrict the span value to either 2 μg/m3 or 10 μg/m3. Commenter recommends that they should be allowed to set the span value anywhere between 2 and 10 μg/m3 as long as that range falls within acceptable limitations of the NIST traceable calibrator. The commenter states that the EPA also proposes that the full-scale range should be set to include the MPC. According to the commenter, the EPA should allow the full-scale range to be set at one number (10), and perform quality assurance testing over a lower portion of that range (0- 5). The commenter also states that 40 CFR part 75 has an annual requirement for the majority of analyzer readings to be between 20 and 80 percent of full-scale, which should not apply to Hg.

Response to Comment 15: In the final rule, greater flexibility in setting the span value is provided; the span value (μg/m^3) is twice the Hg concentration corresponding to the emissions standard, rounded to either the next highest integer, the next highest multiple of 5 μg/m^3, or the next highest multiple of 10 μg/m^3. For certain existing units, the estimated Hg concentration corresponding to the standard is about 1.5 μg/m^3. Therefore, the span value could be set to either 2.0, 5.0, or 10.0 μg/m^3. If the span value is set at 5.0 μg/m^3, the required QA tests (i.e., daily calibrations, linearity checks and system integrity checks) will be performed in the 0-5 μg/m^3 portion of the measurement scale (as suggested by the commenter). Then, provided that the analyzer is capable of reading Hg concentrations as high as the MPC, the span and range requirements of sections 3.2.1.4.1 through 3.2.1.4.3 of Appendix A will be satisfied. The final rule does not require the majority of the Hg concentration data to be within 20 to 80% of the analyzer's full-scale range.

Comment 16: Commenter 17821 opposes the requirement under section 3.2.3.3. to set the span for a CO_2 monitor at a value of 1.25 times the maximum potential value for these flue gas components. According to the commenter, typically, a coal-fired source has a maximum potential CO_2 concentration of approximately 14 percent in the flue gas, and 1.25 times 14 is only 17.5%. The commenter states that other regulations, such as 40 CFR 60 and 40 CFR 75, require the span of a CO_2 monitor to be set at 20 percent. According to the commenter, the difference between these established rules and this proposal results in a conflict of span settings which would require sources to either install and operate a separate CO_2 monitor for compliance with these proposed rules, or conduct a separate span calibration check on an existing CO_2 monitor in order to comply with all applicable requirements. Commenter encourages the EPA to define a span of 20 percent for CO_2 monitors used for compliance with these proposed rules.

Response to Comment 16: The final rule does not include the requirement to set the CO_2 monitor span at 1.25 times the MPC. Section 63.10010(b) requires that all diluent gas monitors used to provide data under Subpart UUUUU must meet the requirements of 40 CFR part 75. Part 75 span values for CO_2 or O_2 monitors are therefore acceptable for Subpart UUUUU and there is no conflict between the regulations. Essentially all coal-fired utility units already have certified part 75 CO_2 or O_2 monitors in place to meet Acid Rain Program requirements.

Comment 17: Commenters 17821 and 17881 object to the requirement at section 7.2.5.1 to submit quarterly Hg monitoring data. According to the commenters, this rule is not based on a cap-and-trade program but on compliance with emission limitations and structured around excess emissions and deviation reporting. The commenters opine that under those types of compliance programs, there is no need for sources to submit hourly monitoring data, along with the other data that is required by this section and later subsections. Commenter 17881 states that the EPA does not justify the requirement to electronically submit data under section 7.2.4.

Response to Comment 17: The EPA disagrees. These provisions provide extremely useful compliance oversight information regardless of whether compliance is market-based or emission limit based. With the existing structures built around Part 75 reporting for these sources, reporting these data through the ECMPS mechanism is an efficient means of ensuring these records are maintained and available for review. Having an hourly record of unit operating time, measured emissions, and monitor outages provides added assurance the emission limits are being met. Electronic audits can be performed to verify that the 30-day rolling average emission rates are being calculated correctly nationwide.

Comment 18: Commenter 18449 states that the Appendix A Performance Specification appears to replace PS-12A in this MACT but not in the other recently prepared MACT rules. According to the commenter, the previous PS-12A document had been created with considerable input from many sources and had undergone several revisions, has worked well for the last 6 years, and required only minor corrections. The commenter states that this new document is an attempt to reconcile some old Part 60 concepts with the second generation CEMS performance specs of the PS series, and in particular combines PS-12A, PS-12B and Procedure 5. According to the commenter, Appendix A mingles Hg monitor performance requirements, which are a function of the continuous Hg monitor, with higher level Hg reporting requirements, which are implemented as higher level functions of the DAS.

Response to Comment 18: The commenter is correct that Appendix A of this rule contains the Hg CEMS and sorbent trap system requirements for Hg monitoring for this rule; the rule does not reference or rely on PS-12A. In addition, Appendix A contains specific recordkeeping and reporting requirements for Hg monitoring data to support entry of the data into ECMPS.

In particular, the final rule requires all CEMS data to be submitted to EPA using the ECMPS Client Tool. The Hg monitoring requirements in Appendix A, which closely resemble the provisions of the vacated CAMR regulation, have been retained in the final rule. Certification and on-going QA provisions like those in Appendix A went through public comment during the CAMR rule making, were published in Part 75 (but have since been removed), and were designed to be implemented through ECMPS. PS 12B is referenced as it is essentially identical to the former Appendix K of Part 75, which was to be implemented through ECMPS under CAMR.

Comment 19: Commenter 18449 states that the requirement to report readings of either CO_2 of O_2, on any constant basis is unnecessary. The commenter states that Hg monitors (or any other pollutant monitor) always report concentrations, either volumetrically (ppm, ppb) or m/v basis (ug/m3). Most CEMS are diluting and report on a wet basis. According to the commenter, the emission limits are given as a mass emission limit per unit of plant activity, and the correction of the pollutant output concentration to a specific CO_2 or O_2 concentration does not in any way facilitate this calculation but adds unnecessary variables that will increase the uncertainty and calculation error. The commenter states that corrected (CO_2 or O_2) pollutant concentrations are not used in any of the subsequent mass emissions calculations being proposed by the EPA for concentration based Hg analyzers.

The commenter states that stack velocities determined using pitot tubes or other measurement devices are not measured on a constant O_2 basis. Thus, according to the commenter, the stack volumes would need to be recalculated on a 7 percent O_2 basis in order to allow calculation of the mass emission rate. The commenter states that the sorbent trap reference method does not report concentrations on a 7 percent O_2 basis and that thus both the reference and CEMS values would have to be corrected to 7 percent O_2. According to the commenter, if the Hg CEMS intrinsically produces a concentration corrected to 7 percent CO_2, these results must be back corrected to yield an as-is value to allow comparison. This is a needless step that complicates matters and introduces errors. The commenter states that most existing CEMS do not have an O_2 monitor. According to the commenter, it is unnecessary and punitive to require the addition of an O_2 monitor to a Hg CEM, which will reduce reliability and accuracy of the overall system. According to the commenter, all commercially available dilution-based Hg CEMS analyzers are capable of directly determining their own dilution ratio by injecting Hg calibration gas at various points within the system, which means that the use of CO_2 or O_2 as a dilution ratio check is not required.

Response to Comment 19: The commenter appears to be objecting to the use of diluent gas, flow rate, and other parametric measurements to convert Hg concentrations to the units of the emission standards. If so, his comments are misdirected. He purports to be commenting on Appendix A, but is actually objecting to the units of the emission standards, which EPA has no intention of revising at this time. In order to express a measured Hg concentration in units of lb/TBtu, an equation from EPA Method 19 is used. The Method 19 equations all contain a diluent gas concentration term and some of them require corrections for the stack gas moisture content. The commenter's assertion that an O_2 monitor is required in incorrect; the final rule allows the diluent monitor to measure either O_2 or CO_2. Finally, if you elect to (or are required to) demonstrate compliance with an electrical output-based Hg limit, a diluent monitor is not required at all---only a flow monitor is needed in that case.

Comment 20: Commenter 18449 states that under the RATA testing section 4.1.1.5 the procedure should require only that the CEMS and reference results be converted and compared to each other on a consistent basis. According to the commenter, the reference method does not report on a diluents basis and Hg analyzers will not report on this basis, and thus any requirement to correct to some reference CO_2 (or O_2) basis needlessly complicates the RA testing.

Response to Comment 20: The EPA agrees with the commenter that for the purposes of this rule, the Hg monitor should be assessed on the basis of how accurately it measures Hg concentrations. Therefore the RATAs must be done on a concentration basis, comparing the $\mu g/m^3$ readings from the reference method to the $\mu g/m^3$ readings from the monitor. This is clearly stated in sections 4.1.1.5.2 and 4.1.2.4 of Appendix A.

Comment 21: Commenter 19114 states that the EPA appears to have overlooked many of the issues that were resolved in the earlier CAMR rulemaking process. The commenter attached its 2005 CAMR comments to further address issues that had previously been addressed in the previous CAMR rulemaking. Some issues identified by the commenter include:

- According to the commenter, the proposed rule does not address the handling of negative values. The commenter recommends that negative values be rounded to zero and use an associated code to indicate the change, which the commenter states is similar to how Part 75 handles negative data. According to the commenter, if instrument drift and allowable calibration error tolerances are included, it is possible to be within the analysis tolerance and read a legitimate negative value.

- Commenter recommends the use of part 72 definitions for CO_2 and flow range determination and the definition for zero gas because, according to the commenter, part 72 is more accurate and provides harmonization between the two rules.
- Commenter recommends an additional option be available for measuring moisture. According to the commenter, if the stack is saturated, a source should be able to use temperature, absolute pressure, and a psychrometric chart to measure moisture. The commenter states that temperature and pressure transmitters can be calibrated with NIST traceable equipment, and a RATA could be performed but would be unnecessary. According to the commenter, during periods when the stack is not saturated, default factors listed in the rule could be used.

Response to Comment 21: Regarding the three issues raised by the commenter:

1. This issue can be handled through the ECMPS Reporting Instructions. There is a Method of Determination Code (MODC) in Part 75 (i.e., MODC "21"in §75.57, Table 4a) that addresses the handling of negative values. The EPA will instruct sources to use MODC 21 and report zero Hg concentration when a negative value is read by a CEMS that is not out-of-control.

2. There are no definitions for "CO_2 and flow range determination" or for "zero gas" in 40 CFR Part 72. The closest thing to either of these terms is the definition of "zero air material" in section 72.2 In view of the confusion of terms and incorrect rule citations, EPA is unable to provide a meaningful response to this comment.

3. The final rule allows the "additional option" for measuring moisture described by the commenter. In cases where the Hg emissions calculations require corrections for moisture, affected sources must account for the stack gas moisture content in accordance with 40 CFR 75.11. The affected source may either: (a) install and certify a continuous moisture monitoring system; (b) use an applicable fuel-specific default moisture value provided in §75.11(b); or (c) petition the Administrator for permission to use a site-specific default moisture value. One of the allowable Part 75 continuous moisture monitoring systems under option "(a)" consists of a temperature sensor and a psychrometric chart, and applies only to saturated gas streams.

Comment 22: Commenter 18023 states that with respect to section 3.2.3.1 Heat Input-Based Emission Limits, when Hg and the diluents (CO_2 or O_2) are measured on different bases (*i.e.*, one wet and the other dry), stack moisture would need to be accounted for. If, however, they are measured on the same basis, asserts the commenter, a stack moisture monitoring system would not be required.

Response to Comment 22: The commenter's statement is true, but the EPA sees no need to make any changes to the rule text. Section 3.2.3.1 of Appendix A clearly states that "in some cases" stack gas moisture content must be considered. The need for moisture correction (or lack thereof) depends entirely on which Method 19 equation is used to calculate the Hg emission rate. The selected Method 19 equation, in turn, depends upon the measurement basis (wet or dry) of the pollutant and diluent gas species. Therefore, it will be obvious to the affected sources if and when moisture corrections are needed.

Comment 23: Commenter 17881 states that the requirements of section 63.10010 for main and bypass stacks conflict directly with those in Appendix A (section 2.4.2 of Appendix A allows installation of a

CEMS on the main stack and the use of maximum potential Hg concentration whenever the bypass stack is utilized). The commenter states that EGUs with multiple stack or duct configurations are addressed in section 63.10010(a)(5). The commenter appreciates the flexibility afforded in this paragraph but opines that the EPA should specify the method used to merge the multiple stacks or duct values into a single value which could then be compared to the emission limit. According to the commenter, in the absence of such guidance, it could be construed that each monitoring location must independently show compliance with the applicable EGU emission limits, and this could result in situations of seeming non-compliance. The commenter questions whether, for example, if Hg monitoring is conducted in A and B ducts associated with a single EGU and one duct monitor shows a compliance value (75% of the limit) while the other duct monitor does not (105% of the limit), compliance actually would be assessed and whether the two duct values should simply be averaged arithmetically, in a flow weighted manner, etc.

Response to Comment 23: For a unit with multiple parallel control devices with multiple stacks or ducts where all stacks or ducts are monitored, section 63.10010(a)(6) of the final rule states that the pollutant emission rate for the unit must be calculated, weighted by stack gas volumetric flow rate, where the weighted average emission rate is calculated according to section 63.10010(a)(6).

Comment 24: Commenter 17881 states that span values for auxiliary measurement systems (i.e., flow rate, diluent gas and moisture monitors) in section 3.2.3.3 contain undefined terms such as maximum potential flow rate and maximum potential concentration. The commenter notes that these provisions are on the surface similar to those found in 40 CFR part 75, albeit without much of the detail necessary to implement the provisions (i.e., how is the maximum potential flow rate or maximum potential concentration determined). questions the commenter, at a minimum, the span, range and maximum potential flow rate/concentration provisions of 40 CFR part 75, Appendix A should be allowed, and it may be prudent to abandon the details contained in section 3.2.3.3 and simply refer to the associated 40 CFR part 75 provisions.

Response to Comment 24: The EPA agrees with the commenter's recommendation to dispense with the details in section 3.2.3. The final rule simply requires all of the additional monitoring systems needed to convert Hg concentrations to the units of the standards to meet the requirements of 40 CFR part 75. This approach is appropriate, since ECMPS will be used to receive and process the CEMS data that are used to assess compliance with the Hg emission limits under subpart UUUUU.

Comment 25: Commenter 17881 states that the cycle time test provisions of part 75, Appendix A, section 6.4 allow a change of < 6% of the average reading over a 6-minute period to define a stable reading when conducting the cycle time test and that this provision should also be allowed in section 4.1.1.4 of Appendix A.

Response to Comment 25: In the final rule, the additional text suggested by the commenter has been added to the cycle time test procedure in section 4.1.1.4 of Appendix A.

Comment 26: Commenter 18449 states that span ranges will be difficult since pollutants are not expected to vary over a wide concentration (during normal operation as compared to startup). Commenter 18449 suggests the EPA update the span wording in PS-12A and Appendix A, where it allows 10 ug and multiples of 10 ug; commenter 18449 states that multiples of 10 ug doesn't work for very low Hg values as in Utility MACT, where a span range of 5 ug/m3 might be more appropriate. Commenter 18449 states that each defined span range requires a set of two different gases (Hg- and Hg2+), each at three different concentrations (20-30 percent, 50-60 percent, and 80-100 percent of span), which is a problem for both suppliers and NIST, and suggests the number of spans be minimized.

Commenter 18449 states that utility MACT spans should be fixed at 5, 10, 20, and 40 ug/m3. (Commenter 18449 states that Cement MACT spans should not be available in increments of 10 ug but should be spaced much farther apart, such as 100, 180, 260, etc. Commenter 18449 states the wording should be clarified so that users can choose such ranges, rather than forced to nearest multiple of 10.)

Commenter 18449 states that CAMR also required Hg calibration gases be traceable to NIST, however, NIST at that time had no idea how to certify Hg generators or calibration gases and had to develop the methodology, procedure, and processes, with no protocols in place until well after the start of the program, so that the EPA was forced to defer the NIST traceability requirement for a year. Commenter 18449 notes that the EPA and NIST still have a number of current issues, for which NIST will require external funding, and identified these issues as follows:

1. Measure and certify lower level elemental concentrations. According to the commenter, currently NIST can only certify concentrations down to 0.5 µg/m3, and this value has a very high uncertainty of 6.1 percent (Prob_95 percent). The commenter states that NIST will have to be able to certify points at 20-30 percent of the lowest span value that the EPA envisions; for example, a 0.25 µg/m3 certified concentration would be needed for lower span ranges.

2. Measure and certify high elemental concentrations (100 to 260 µg/m3). The commenter states that this is required for the Cement MACT rather than this rule, but it's included here since it has to be done.

3. Measure mercury chloride generators. According to the commenter, currently there is a 9 percent discrepancy between NIST traceable elemental calibrators and NIST traceable ionic evaporative calibrators, and the reason for this is unknown. The commenter states that if NIST could accurately measure the output of evaporative calibrators, this difference could be explained. According to the commenter, the current Interim Oxidized Protocol deems a generator to be certified if all inputs are NIST traceable. The commenter states that this approach can remain, but the ability of NIST to confirm the output of even a single test ionic generator would increase confidence that the various types of generators all yield identical output concentrations.

4. Improve "routine" elemental certifications. The commenter states that certifications of elemental calibrators by NIST over the range 0.5 to 38 µg/m3 have been "routine" for several years, but it recently took three separate attempts with NIST and over one year for the commenter to have a pair of calibrators correctly certified over this range. The commenter states that the high levels were correct, but the low concentrations were off by up to 12 percent, and if legislation been in place, this delay would have caused enormous problems.

5. The EPA Interim Traceability Protocols currently state: "For CEMS applications, this protocol applies only to Hg monitoring system span values greater than or equal to 5.0 micrograms per cubic meter (µg/m3)" According to the commenter, this must be changed if the EPA envisions span values of less than 5 µg/m3 will be required under the new legislation. The commenter states that rovided that NIST can provide lower uncertainties for lower concentrations for elemental generators, the commenter does not see any reason why the interim protocols will not work at the lower concentrations needed for a 2 µg/m3 span range.

6. Vapor pressure of mercury. The commenter states that there is a 7 – 9 percent difference between two proposed mercury vapor equations. According to the commenter, these equations are used to predict the output concentration of saturated vapor elemental mercury generators running at a specific temperature; one equation has been in use for decades and been experimentally verified on an ongoing basis, even by

the NIST Gas Metrology Group, and the other, recently proposed by another group within NIST (Boulder Colorado) predicts a mercury concentration in saturated vapor 7 to 9 percent higher but as viewed as "theoretically correct". The commenter states that although the EPA's Interim Elemental Mercury Traceability Protocol neatly sidesteps this issue, it has worldwide implications for the accuracy of all measurements of mercury in air or other gases.

Response to Comment 26: The EPA disagrees that fixed span values should be specified in PS-12A or Appendix A; however, in the final rule, the EPA has revised Appendix A, which includes the Hg monitoring requirements specific to this rule, to enable greater flexibility when identifying an appropriate span value. The Appendix A requirements provide for identifying a potential span value (based on a level two times the Hg concentration equivalent to the emission limit), but also provides options for rounding the span value to either the next highest integer, the next highest multiple of 5, or the next highest multiple of 10. In regard to Item 1, the EPA disagrees that NIST will have to be able to certify elemental Hg concentrations less than 0.5 $\mu g/m^3$ at this time. No span values (i.e., a span value less than 5 $\mu g/m^3$) that would require certified elemental Hg concentrations less than 0.5 $\mu g/m^3$ are required by the final rule. The EPA does, however, encourage the development and use of lower span ranges (that meet Appendix A), where appropriate. If a span value is chosen that requires the use of certified elemental Hg concentrations less than 0.5 $\mu g/m^3$, NIST would be capable of conducting certifications at this level, though as far as the EPA is aware NIST has not yet conducted certifications at these low levels. Regarding Item 2, the EPA agrees that higher level elemental Hg calibration gas concentrations are needed for potential future regulatory requirements independent of this rule. The EPA has worked with NIST to expand the range of NIST elemental Hg reference concentrations that can be certified and certified elemental Hg concentrations ranging from 0.5 $\mu g/m^3$ to 300 $\mu g/m^3$ are now available. Concerning Item 3, the EPA agrees that NIST possessing an ability to accurately measure the output of evaporative mercuric chloride generators is desired; however, in the absence of this capability, the current Interim Traceability Protocol for certifying oxidized Hg gas generators is accepted as the appropriate methodology for establishing NIST traceability for mercuric chloride. Moreover, this approach reflects significant effort on the part of the EPA, the CEMS vendor community, and affected sources to examine the calibration generator traceability issues, and devise an agreed upon approach for addressing those issues. For Item 4, it is the EPA's understanding that NIST currently performs elemental Hg gas generator certifications on a routine basis and the EPA is unaware of any problems in this regard. The EPA disagrees with the assertion in Item 5 that the EPA must revise the Interim Traceability Protocol; span values less than 5 $\mu g/m^3$ are not required by this rule and as a result, changes to the Interim Traceability Protocols are not necessary for implementation of the rule. The EPA does agree with the commenter that the EPA Interim Traceability Protocols are suitable for lower elemental Hg concentrations such as those associated with a 2 μg/m3 span range. In fact, NIST and at least one vendor are capable of certifying elemental Hg generators at concentrations as low as 0.5 $\mu g/m^3$, so the EPA will consider modifying the protocol at a later time. Finally, regarding Item 6, while the EPA is aware that there is a 7 to 9% difference between two Hg vapor equations used by the scientific community, the EPA's application of NIST traceability for elemental Hg is empirically based upon an unbroken chain of comparisons anchored to an accepted, NIST elemental reference gas which is independent of these theoretical Hg vapor equations.

5A07a - Testing/Monitoring: Application of PM CEMS

Commenters: 17197, 17383, 17402, 17621, 17623, 17638, 17655, 17675, 17677, 17681, 17689, 17696, 17702, 17704, 17705, 17711, 17714, 17716, 17725, 17728, 17729, 17730, 17737, 17740, 17747, 17752, 17754, 17756, 17758, 17761, 17774, 17775, 17790, 17795, 17796, 17798, 17800, 17801, 17808, 17812, 17813, 17818, 17820, 17821, 17868, 17871, 17881, 17886, 17912, 17913, 17914, 17975, 18014, 18428, 18443, 18447, 18498, 18831, 18935, 18963, 19033, 19114, 19120, 19121, 19536, 19537, 19538, 18023

1. Support of use of PM CEMS during startup and shutdown.

Comment 1: Commenter 17975 supports the proposed requirement to use PM CEMS on EGUs that elect to comply with the PM filterable limit as a surrogate for non-Hg metals because PM CEMS are an EPA approved monitoring method, and in use at an increasing number of plants. The commenter believes that the EPA needs to make the final rule clear that PM CEMS must be operated around the clock, including during startup, shutdown, maintenance, and malfunctions, when PM emissions may be at their peak. The commenter refers to an "expert's" conversations with several PM CEMS vendors that indicate these monitors can be calibrated to accurately measure PM at very high concentrations that occur during startup and shutdown.

Response to Comment 1: The final rule clarifies that the operating limit monitoring for the PM and HAP metals emission limits requires use of a PM CPMS, not PM CEMS, and work practice standards that include operation of monitoring, not numerical emissions limits, during periods of startup or shutdown. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

2. Recommendations to use PM CEMS as indicator/CAM.

Comment 2: Multiple commenters (17705, 17725, 17716, 17820, 17886, 18014, 18498) suggest that the final rule use PM CEMS data as an indicator of PM control performance, but not to enforce a numeric PM limit, and that alternatively, sources could also demonstrate a reasonable assurance of compliance based on opacity or parametric monitoring as the EPA has already proposed under other rules.

Comment 3: Several commenters (17623, 17638, 17681, 17676, 17775, 17886) suggest using PM CEMS within a MACT monitoring program modeled after the part 64 CAM program.

Comment 4: Several commenters (17402, 17716, 17737, 17775, 17886) believe current PM CEMS technology is useful as a compliance assurance monitoring tool that can trigger requirements for investigation and corrective action.

Comment 5: Several commenters (17402, 17681, 17716, 17737, 17775) note successful implementation the CAM rule under 40 CFR part 64 and request that the final rule adopt this approach for continuous monitoring. Commenter 17402 suggests that CAM plans could include opacity monitoring, a site-specific utility MACT compliance plan, and periodic stack testing.

Response to Comments 2 - 5: The final rule requires the use of a PM CPMS for an operational limit and does not enforce a numeric PM limit when this monitoring approach is used. In the final rule facilities would be allowed to petition the Administrator under section 63.8(f) of subpart A of part 63 for an alternative to use opacity or parametric monitoring at a specific site in lieu of required monitoring in the final rule. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

3. Requests for clarification on establishment of PM CEMS operating limits.

Comment 6: Commenter 17729 requests clarification that the rule requires using the filterable PM measurement to set an ongoing 30-day rolling average operational limit with compliance based on a filterable PM CEMS.

Response to Comment 6: The final rule requires the use of a PM CPMS for an operational limit and does not enforce a numeric PM limit. The PM CPMS is required to report measurements in raw data output from the monitor and not a correlation to manual filterable PM measurements. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 7: Commenter 17881 states that it is not clear if section 63.10011(b)(3) applies to units with PM CEMS. Commenter notes that for a unit complying via the use of PM CEMS, it is not clear if "non-Hg HAP metals" refers to the aggregate of all regulated HAP metals or each of the individual HAP metals. According to the commenter, it seems like this provision must be based on all metals in aggregate, or it would be impractical to implement.

Response to Comment 7: The final rule requires the use of a PM CPMS for an operational limit and does not enforce a numeric PM limit. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). The source has the option to measure non-Hg HAP metals with a reference method each quarter. The monitoring and testing that is required will depend on which emission limit the source elects.

Comment 8: Several commenters (17730, 17868, 18023) state that proposed reliance on total PM as a surrogate for the non-Hg HAP metals, and the use of the PM CEMS to conduct performance testing and measure ongoing compliance is poorly defined. Commenters (17800, 18023) state that the provisions in Table 4 ("highest 1-hour average") are inconsistent with the provisions in proposed section 63.10011(d) for determining the filterable PM operating limit. According to commenter 17730, the proposal requires that when sources conduct the initial performance test, they must develop a filterable PM emission limit based on a compliant stack test using Method 5 and Method 202, but the proposal fails to provide any further explanation of how sources are supposed to derive the filterable PM limit, or whether or not sources are also required to comply with the individual HAP metals emission standards. The commenter believes that there are several calculations that could be used to determine a filterable PM limit based on stack test results but that the exact calculation is not specified in the proposal. The commenter characterizes this portion of the proposal as "essentially establishing a surrogate for measuring a surrogate" and "simply nonsensical." The commenter believes it is unreasonable for the EPA to seek comment on such a poorly defined proposal, and the commenter believes that if the agency continues to pursue the total PM standard as a surrogate for non-Hg HAP metals, the agency should make clear the methodology for establishing the filterable PM limit and re-propose the rule for public comment because the commenter cannot effectively provide comment without further definition.

Response to Comment 8: We are no longer requiring use of a PM CEMS for a PM limit. We are requiring the use of a PM CPMS for an established operational limit. The source has the option to measure non-Hg HAP metals with a reference method each quarter. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 9: Several commenters (17754, 17800,18963, 18023) state that the owner/operator must "[m]aintain the PM concentration (mg/dscm) at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the total PM emissions limitation,". and that proposed section 63.10011 directs that the operating limit for PM should be based on the average of the PM filterable results of the three Method 5 performance test runs, whereas Table 4 provides that the PM limit shall be the highest 1-hour average measured during the most recent performance test. According to the commenters, these two relevant provisions appear to reflect inconsistent analyses and compliance demonstration periods and therefore should be clarified in order to avoid potential confusion, misinterpretation, and/or inconsistent application. The commenters request that the proposed rule be clarified to expressly provide that the operating limit for demonstrating continuous compliance with the emission standard for total PM shall be based on the highest 1-hour average measured during the most recent performance test, in accordance with Table 4 of the proposed rule. The commenters state that consistent with this approach, if the total PM emissions from an affected EGU exceed the previously-established operating limit during any period, the owner/operator of such unit would have the option of conducting another performance test, and the highest average value measured during such test would become the new applicable operating limit for the relevant unit.

Response to Comment 9: Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals (or HAP metals inclusive of mercury for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 10: Commenter 17871 states that the EPA has failed to demonstrate that a functional relationship between filterable particulates and condensable particulates in EGUs. According to the commenter, this approach becomes unworkable when one considers the rule requires annual testing resulting in new standard for non-Hg metallic HAP every year. The commenter notes that under the proposed rule, the use of SO_2 as a surrogate for acid gas HAP is appropriate because the EPA has correctly noted that "the technologies used for removal of acid gases are primarily those that are also used for FGD" (76 FR 25023). The commenter states that SO_2 would be measured with a CEMS certified and operated in accordance with part 75. According to the commenter, even though proven technology and quality assured emission data is used to demonstrate compliance with the standard, a "second MACT standard" has been created that requires that the sorbent injection rate be maintained at or above the lowest 1-hour average sorbent flow rate measured during the most recent performance test. Commenters 17871 and 17740 state that by setting up compliance in this manner, the emission standard becomes the basis for an operating limit, which in turn becomes another, far more stringent, standard of compliance that a facility would be required to meet on a continuous basis. According to the commenters, this is inconsistent with the purpose of an emission standard, which allows for fluctuations in emissions over a 30-day period and improperly imposes two MACT standards on sources.

Response to Comment 10: The comments are inapplicable, as the final rule no longer contains a condensable PM emissions limit and, for those source owners or operators who choose to use SO_2 CEMS, no operating limit exists and no parameter monitoring is required.

Comment 11: Commenter 17623 states that the total PM standard is unclear and impracticable because it will be difficult for sources to plan for changes to the limits resulting from performance testing. According to the commenter, the PM limit of 0.030 lb/MMBtu for existing sources would be adjusted downward based on the PM emission rate measured by the reference method during each periodic performance test. The commenter believes that there are two possible interpretations of the proposed rule that would result in this downward adjustment.

1. According to the commenter, one interpretation would require the PM limit to be adjusted down based on the proportion of Total PM emissions that are condensable. The commenter states that if, for example, 50 percent of the total PM emissions are condensable at a particular unit, then the applicable PM CEMS limit for that unit would be reduced to 0.015 lb/MMBtu.
2. According to the commenter, the other interpretation would require the PM limit to be set at the actual filterable PM emissions rate measured during the initial and subsequent PM performance tests conducted for the unit. The commenter states that under either approach, the conversion of the total PM numeric rate limit into a filterable PM standard that a PM CEMS can monitor will require sources to readjust their compliance level after each performance test.

Response to Comment 11: Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals (or HAP metals inclusive of mercury for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 12: Commenter 17795 states that there is conflicting language in the proposal. According to the commenter, pages 25029-25030 indicate that ESP and fabric filter parameter monitoring is required for all units not using HCl CEMS, but the language from page 25031 states that parameter monitoring is required only if units are not using PM CEMS. According to the commenter, fabric filter BLDS and ESP voltage limit monitoring requirements should apply only to units that do not use PM CEMS as stated on page 25031. The commenter believes this was the EPA's intent, as there is no justification or further assurance of compliance for the monitoring of particulate control equipment operational parameters when direct continuous monitoring of filterable PM is implemented. According to the commenter, the EPA should clarify that it did not intend to make ESP voltage and fabric filter BLDS readings an operational limit if a unit uses a PM CEMS to demonstrate compliance.

Response to Comment 12: Control equipment parameters are not monitored under the final rule, so this concern is moot.

4. Concerns with using PM CEMS data to determine compliance with non-Hg metals standard.

Comment 13: Commenter 17621 states that the merits of including condensable PM in the total PM limit are difficult to evaluate, as no test data are available for the exact condensable PM method that is required for compliance with the proposed MACT limits. The commenter states that the ICR required condensable PM to be measured using OTM-28, which method was changed significantly before it was promulgated in 2010 as revised Method 202. According to the commenter, most ICR test contractors used OTM-28, a few used the original Method 202, and because none of the ICR tests used revised Method 202, the conclusions of EPRI's evaluation of condensable PM method usefulness are uncertain. According to the commenter, adding a condensable PM measurement to the filterable PM sampling train increases the total variability and reduces the sensitivity of the combined measurement system. The commenter states that a recent field study conducted by American Electric Power (AEP) and EPRI found that Method 202 (condensable PM) had much higher variability than Method 5 (filterable PM) for replicate test runs (EPRI, 2011) and that in the ICR Part III tests at coal-fired EGUs, the relative standard deviations (RSDs) of condensable PM test series averaged slightly higher than the RSDs of filterable PM test series (24 percent compared to 20 percent). According to the commenter, the detection limit of a combined Method 5/Method 202 sampling train is twice as high as that of a Method 5 train alone, as each gravimetric measurement adds uncertainty to the total.

Moreover, according to the commenter, the accuracy of the new Method 202 has not been demonstrated adequately and requires additional research. The commenter states that laboratory studies conducted by EPRI pointed to a potential negative bias in OTM-28, which did not effectively capture SO_3 (EPRI, 2009)., and that only about half of the SO_3 introduced into the sampling train was captured. According to the commenter, this finding indicates that Method 202 may not be accurate under flue gas conditions that are expected to be increasingly prevalent in power plants as wet FGD systems (which tend to produce SO_3) are added.

The commenter states that a total PM limit is problematic for compliance monitoring, as continuous PM monitors measure only filterable PM. According to the commenter, since condensable PM emissions are a product of the coal sulfur content and other factors (e.g., ash properties, SCR SO_2 oxidation rate), it is not clear how a power plant would determine compliance with the total PM limit without being able to monitor both filterable PM and condensable PM on a continuous basis. The commenter asserts that the difficulty of demonstrating and achieving compliance with total PM limits will depend on the percentage of total PM that is condensable PM and how variable the ratio of filterable PM to condensable PM is over time. Commenter states that (in document; Figure 2-2 is histogram of condensable PM as a percentage of total PM: Part III ICR Coal-fired EGUs) the fraction of total PM that is condensable PM varies from under 1 percent to over 99 percent across the coal-fired EGUs tested in the ICR. According to the commenter, the ICR database does not contain sufficient historical condensable PM data to determine how much condensable PM emissions will change at a unit over time.

Finally, the commenter states that EPRI's study has implications for how representative the ICR data are of industry emissions, as well as for future performance testing. The commenter states that the EPA based the MACT floor for total PM on the lowest test series for each EGU, regardless of the method used to measure filterable PM (Method 5, Method 29, or OTM-27). According to the commenter, as many of the lowest ICR emissions are from Method 29 tests run at 320 °F, those results will not be representative of tests made using Method 5 at 250 °F, and as a result, there is considerable uncertainty regarding the true emissions of filterable PM from the power industry. The commenter states that the compliance method for filterable PM specified in the proposed rule is Method 5, while the ICR test data include filterable PM results from Methods 5, 29, and OTM-27. According to the commenter, to eliminate the various method biases identified in the EPRI/AEP study, the requirement to run Method 5 tests at 320 °F should also apply to Method 29 metals tests, and there should be a requirement to use nonreactive filters.

Comment 14: Commenter 18429 states that the unit-by-unit, single test approach in setting a MACT limit proposed by the EPA is inappropriate. The commenter notes that an example of the difficulty in meeting a PM operational limit is one of the commenter's units equipped with a wet scrubber, SCR, and ESP for emissions controls. According to the commenter, when following the stack test that would establish the filterable PM operational limit, the unit's PM CEMS consistently recorded 30-day averages above that level, because the initial filterable PM level was measured while the boiler was operating in a steady-state, full load condition over a brief period of only hours, and the PM CEMS then measures filterable PM levels continuously during all load and operating conditions. According to the commenter, the EPA's proposed approach punishes good behavior and is a setup for failure. The commenter encourages the EPA to replace a total PM with a category-wide, filterable PM limit that is achievable under the variety of conditions that utility units experience. The commenter further notes the comments submitted by EPRI in this docket provide detailed analysis justifying the use of filterable PM as an adequate surrogate for all non-Hg metals. The commenter states that among the key conclusions are that filterable PM is correlated to emissions of particulate-phase metals (e.g., chromium) and there is a statistically significant correlation with metals that are volatile at stack gas temperature, particularly Hg and selenium.

Comment 15: Commenter 17197 believes the proposed PM CEMS operating limit determination method is unworkable, arbitrary, likely overly restrictive, and non-representative. The commenter believes the better solution is replacing the proposed total PM limit with a filterable-only PM limit for non-Hg HAP metals using PM CEMS, however the commenter offers an alternative. Commenter recommends instead that the surrogate PM CEMS operating limit (filterable PM) be established by using the simultaneous EPA Method 5 and Method 202 stack testing results to establish the EGU's filterable-to-total PM ratio. According to the commenter, the PM CEMS operating limit (filterable PM) would be appropriately set by adjusting the total PM limits (0.030 lb/MMBtu or 0.30 lb/MWh) using the filterable-to-total PM percentage established during the three 1-hour test run performance testing. The commenter states that for example, if the measured filterable-to-total PM factor was 0.5, the PM CEMS operating limits (filterable PM) would be set at 50 percent of the total PM Limits (0.015 lb/MMBtu or 0.15 lb/MWh). According to the commenter, setting the PM CEMS operating limit using this alternate methodology is more representative because it utilizes all three performance test runs and not just the highest 1-hour average measured EPA Method 5 rate. The commenter asserts that this methodology is less dependent on short-term PM control system performance, since it is based on the established filterable-to-total PM ratio, and is less arbitrary since the resulting PM CEMS operating limits have some equivalence to the underlying total PM limit.

Comment 16: Several commenters (17623, 17677, 17681, 17730, 17775, 18023) believe that it is problematic to use PM CEMS data to determine compliance with a total PM limit because PM CEMS only measure filterable particulate. Commenters (17623, 17775) states that the technology used to establish the total PM limit and to perform periodic stack tests that re-set the "floating" PM CEMS operating limit use significantly different technology. Commenter 17775 states that the proposal does not indicate that the agency considered how the permissible PS-11 measurement error might impact compliance determinations. Commenter 17677 is concerned that the PM CEMS operating limit appears to be an enforceable requirement treated as equivalent to the total PM limit despite the fact that the PM CEMS limit reflects only a fraction of the total non-Hg metals being emitted during the performance test. Commenter 17677 believes that setting an enforceable limit on a surrogate seems refutable during enforcement proceedings. Several commenters (17623, 17677, 17681) suggest requiring another stack test for total PM within 60 days of exceeding the PM CEMS operating limit rather than deeming the source out of compliance with the HAP emissions limit. Commenters (17676, 18023) believe that annual compliance tests are sufficient to ensure compliance.

Comment 17: Several commenters (17689, 17704, 17813, 18014) state that the proposed PM total approach is unworkable for several reasons. According to the commenters, Methods 5 and 202 would be utilized to determine the condensable and filterable portions of PM total, with PM CEMS measurements used to set unit operating limits afterwards, but Method 5 does not and cannot account for variations in PM filterable actual levels over a range of unit operating levels, including startup and shutdown, that a PM CEMS would measure, so, in effect, Method 5 measurements when compared to PM CEMS measurements over full unit operating conditions is not appropriate. Several commenters (17689, 17702, 17704, 17813) state that the PM standard should be based on a PM filterable limit only.

Comment 18: Commenter 17737 states that PM CEMS provide an indirect measure by "correlating" the monitor's response to short term stack tests (e.g., Method 5 tests) conducted over a range of concentrations that must be sufficient to include the level of the applicable emission standard. Commenter provides an analysis by UARG that indicates that a PM CEMS meeting the criteria in PS 11 can produce responses that differ significantly (on the order of 25 percent) from what would be obtained with Method 5. (See, e.g., UARG Comments, EPA-HQ-OAR-2002-0058-2880 at 51-54; EPA-HQ-OAR- 2005-0031-0246, at 3-10). According to the commenter, for example, if the filterable PM limit is set at 0.030 lb/MMBtu and the Method 5 test result is 0.028 lb/MMBtu, emissions would be compliant with the filterable PM limit, but with the allowed measurement error of 25%, the PM CEMS could present a PM level of 0.035 lb/MMBtu and thus demonstrated false exceedance of the PM limit where the true PM level should have be in compliance.

Response to Comments 13 - 18: The final rule no longer requires monitoring with a PM CEMS. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 19: Commenter 17737 states that they conduct Method 5 performance tests each year, and the results of those tests have varied as much as 80 percent for a given unit. According to the commenter, the EPA provides no data or explanation as to how this operating limit might address this variability in operating conditions that are certain to occur. According to the commenter, this is likely because the three-run average of a stack test conducted during 1 day at constant operating conditions, essentially represents a single point measurement, which by its very nature cannot provide any indication of variability. Several commenters (17737, 17790, 18014) state that use of the EPA's proposed method of setting the operating limit would leave compliance with that limit completely to chance (i.e., dependant on the performance test results), and utilities would not know what their operating limit was until compliance with that standard was in effect, leaving no opportunity to prepare for the standard. The commenters note that the EPA must modify its standard to allow units to comply.

Response to Comment 19: Under the final rule sources are allowed to establish different operating limits monitored with a PM CPMS if they believe there is variability due to varying load conditions. The final rule no longer requires monitoring with a PM CEMS. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 20: Commenter 17711 states that PM CEMS measure only filterable PM yet the EPA proposes that the operating limit for facilities using PM CEMS is the highest 1-hour average concentration in mg/dscm measured during the most recent performance test. According to the commenter, the EPA is setting an artificially low PM standard for units using PM CEMS. The commenter states that the compliance method should match the standard; the EPA should either set filterable PM emission limits or establish more appropriate operating limits for sources using PM CEMS (e.g., the total PM limit minus the amount of condensable PM measured during the last performance test).

Response to Comment 20: Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 21: Commenter 19120 states that the establishment of an operating limit makes the 0.030 lb/MMBtu limit on total PM arbitrary. According to the commenter, for example, if the emissions rate during stack testing for total PM is well below 0.030, exceedance of the filterable PM operating limit would not be an indication that the actual emissions limit of 0.030 lb/MMBtu was exceeded or even approached. The commenter recommends that the EPA base the operating limit on a more representative value than simply basing it on the value achieved during the stack test and notes that while section 63.10011(d) indicates that the operating limit will be based on the average of the PM filterable results of the three Method 5 performance test results, Table 4 indicates that the operating limit will be based on the highest 1-hr average measured during the test.

Response to Comment 21: Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). Under the final rule sources are allowed to establish different operating limits monitored with a PM CPMS if they believe there is variability due to varying load conditions. The final rule no longer requires monitoring with a PM CEMS. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 22: Several commenters (17402, 17775, 17790) support use of PM as a surrogate for non-Hg HAP metals. Other commenters (17402, 17675, 17716) request that the agency not require regulated units to install and use PM CEMS as the continuous compliance determination method. Several commenters (17402, 17716, 17775) support inclusion of PM CEMS as one option among others for an appropriate filterable PM limit, provided the EPA has considered and addressed all of the issues associated with use of PM CEMS for that purpose. Commenter 17402 states that including PM CEMS as an option would be consistent with recent revisions to NSPS Subpart Da. However, the following commenters do not believe that the proposal accounts for the following issues relevant to the use of PM CEMS as a direct indicator of compliance following periodic performance tests:

1. Multiple commenters (17402, 17675, 17681, 17696, 17716, 17728, 17737, 17752, 17775, 17790, 17868, 18023) note the inaccuracy of PM CEMS at low concentrations;
2. Multiple commenters (17402, 17716, 17728, 17737, 17752, 17775, 17790, 17868, 17886, 18014, 18023) state there is a lack of data correlating PM CEMS response with actual emissions during startup and shutdown and across load ranges. Commenters (17775, 17737) state that the proposal's explanations (that the proposed limits were achievable during periods of startup and shutdown based on use of a 30-day averaging period and assumptions regarding the use of cleaner fuels) were not substantiated with data;
3. Multiple commenters (17402, 17675, 17681, 17696, 17716, 17728, 17775, 17868, 18023) are concerned about the PM CEMS allowed measurement error (i.e., high degree of uncertainty within PS-11 tolerance interval);
4. Multiple commenters (17402, 17716, 17728, 17737, 17752, 17775, 18023) note the differences in measurement methods or conditions that can affect monitor calibration;
5. Multiple commenters (17402, 17675, 17681, 17696, 17716, 17728, 17775, 17790, 17868, 18023) question the achievability of PS 11 performance criteria at the low emission limits proposed. In particular, commenter 17775 provides an analysis by a consultant that indicates the PM CEMS are not a viable compliance option and alleges that proposed PM limits are so low that existing PM CEMS technologies cannot pass PS-11 criteria;
6. Commenters 17737 and 17775 claim there is a lack of compliance provisions allowing the operational flexibility necessary to develop strong PM CEMS correlations to the reference method
7. Several commenters (17696, 17737, 17752, 17775, 18023) question the long-term reliability of PM CEMS and long-term stability of measurement responses of current PM CEMS technologies
8. Commenter 17868 notes the lack of alternate limits for PM, SO_2, HCl, and Hg during periods of PS-11 testing;
9. Commenter 18023 states there is a lack of NIST traceable PM daily calibration standards:
10. Commenters 18023 and 17790 state the use of PM CEMS is cumbersome, expensive, and includes highly variable calibration procedures.

Response to Comment 22: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 23: Commenter 17737 states that the EPA should establish a separate standard for periods of startup and shutdown. According to the commenter, however, if the EPA promulgates a rule that requires use of PM CEMS as a compliance method during periods of startup and shutdown, the EPA cannot simply assume that averaging time or differences in fuel will compensate for these period.

Response to Comment 23: The comment is moot, as the rule no longer has emissions limits applicable during periods of startup or shutdown.

Comment 24: Commenter 17800 states that the EPA should revise the compliance procedures for the non-Hg metals standard. Commenter believes that the EPA's proposed compliance procedures for the total PM standard are not workable because the EPA does not clearly describe how compliance would be determined or how the proposed site-specific limit would be established or how the limit would apply. Commenter is opposed to a site-specific limit. The commenter states that a PM standard should apply consistently for all affected sources and compliance must be established that accurately represents the actual emissions from the source and test methods should be clarified and not combine different testing and measurement components.

Response to Comment 24: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

The establishment of an operational limit is described in the final rule and is applied the same for all sources, thus representing the operation of control equipment for all affected sources.

Comment 25: Commenter 17820 states that the EPA should designate filterable PM and not total PM as a surrogate for the non-Hg metals standards. According to the commenter, however, if total PM is retained the EPA should allow an alternative option to determine a unit-specific filterable PM limit and the EPA should extend the option to use filterable PM as a surrogate for metals to oil units and to allow compliance demonstrations through the use of CEMS.

Response to Comment 25: The rule has a filterable, not total, PM emissions limit.

Comment 26: Commenters 17812 and 17821 state that given the variability in testing and coal properties, the requirement to maintain PM concentration at or below the highest 1-hour average measured during the most recent performance test as proposed imposes a de facto unjustified reduction in emission limit on those units using a PM CEMS. Commenter 17821 recommends deleting the requirement in its entirety.

Response to Comment 26: Under the final rule sources are allowed to establish different operating limits monitored with a PM CPMS if they believe there is variability due to varying load conditions. The final rule no longer requires monitoring with a PM CEMS. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

5. Compliance costs if PM CEMS are not appropriate monitors for non-Hg HAP metals.

Comment 27: Commenters 17728 and 17775 state that if PM CEMS are not a realistic option for monitoring PM as a surrogate, then the EPA must reconsider its assumptions that most sources will opt to use PM as a surrogate, and should seriously consider the reasonableness and cost of the non-Hg HAP metals testing option, including the impact of control device parametric monitoring options.

Response to Comment 27: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). If the PM CPMS option is not chosen, then sources are required to perform quarterly testing to show compliance. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

6. Concerns about the commercial readiness of PM CEMS.

Comment 28: Commenter 17818 states that it is their understanding that continuous PM monitoring systems (PM CEMS) have been in operation for a number of years in other countries, and that a number of PM monitors have been in operation in the U.S. for several years as a result of applicable state requirements. According to the commenter, there are a number of commercially available continuous PM monitoring technologies that are capable of meeting the EPA requirements. The commenter states that information from the ICAC indicates that they have prepared a guidance document to help potential purchasers of PM CEMS to prepare a bid specification for the solicitation of bids from particulate monitor suppliers. Commenter agrees with the EPA that PM CEMS are commercially available and are reasonable monitoring options for coal- and oil-fired units. It is the commenter's opinion that PM CEMS are appropriate systems for monitoring compliance with the applicable provisions of the proposed rule.

Response to Comment 28: See response to comment 37.

Comment 29: Commenter 17796 supports the use of Hg CEMS but does not believe the use of PM CEMS is supportable. According to the commenter, the EPA supports the "feasibility" of the PM CEMS by pointing to few facilities which have installed CEMS and to the Performance Specifications for evaluating compliance under 40 CFR Part 60. According to the commenter, there is no rigorous demonstration that PM CEMs are feasible for general application, such as the process it went through to finalize the Method 201/202 filterable and condensable particulate forms which it finalized in January of 2011. The commenter reviewed the Supporting & Related Material portion of the Docket for the PM CEMS program and in over 3000 documents only found four that clearly dealt with PM CEMS, from two facilities in Ohio and that simply reported the hourly measurements. The docket should show more examples of facilities using PM CEMS and also the QA steps necessary for good data. According to the commenter, the docket also needs to show that the PM CEMS equipment will be readily available and also be able to be installed and troubleshot in a timely manner. The commenter states that a similar process with public input must be followed by the EPA to assure that information gathered from the CEMS is valid and, more important to state agencies, that such information can be relied upon to enforce in case of non-compliance.

Commenter 17796 also notes that the EPA's proposal to use CEMS as an option for PM compliance only affects the filterable portion of the PM and relies on the concept that the condensable portion will be addressed though the demonstration of "equivalency" between the CEMS and the stack testing during the initial compliance tests. According to the commenter this is a very tenuous position to rely upon to assure compliance with the total PM limits. The commenter notes that the New York SDEC has a longstanding policy of requiring that the condensable portion of PM emissions be addressed in the permitting process since this portion of the PM emissions are critical for the mitigation of health effects associated with $PM_{2.5}$. Thus, the commenter believes the PM CEMS approach is not adequately rigorous to assure enforceability of the limits, nor allows for the necessary assurance of reducing PM levels to address $PM_{2.5}$ emissions. Finally, the commenter still has many questions as to reliability of PM CEMS and how much experience with this equipment exists. The commenter states that the preamble stated "several electric utility companies in the U.S. have now installed or are planning to install PM CEMs. The commenter questions how many different types of EGUs have PM CEMS (broken down by unit configuration and fuel type). Finally the commenter notes that the costs of PM CEMS are equivalent to installing a Hg CEMS which is also required unless the source owner goes with sorbent traps which are estimated to have less upfront costs but higher annualized costs.

Response to Comment 29: Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

The final rule also includes the option to install and operate PM CEMS if the source chooses to comply with the filterable PM emissions limit. To apply this option, the source would have to meet Performance Specification 11 and procedure 2 of 40 CFR part 60 appendices B and F, respectively.

Comment 30: Commenter 17621 notes that there are almost 70 PM CEMS operating on EGUs in the U.S. Over 40 are installed on wet stacks (following FGD systems). According to the commenter, PS-11 requires a minimum of 15 Method 5 test runs to develop a calibration curve for the CEMS and as a practical matter, the lowest point on the calibration curve is the normal operating point of the CEMS. According to the commenter, the only way to expand the operating range is to de-tune the power plant control equipment to provide up-scale readings to the instrument while conducting the Method 5 manual testing. The commenter states that while this approach has been demonstrated with some success on dry stacks by de-tuning the ESP, it has not been attempted on units equipped with fabric filters. The commenter asserts that wet stack applications present further challenges, since de-tuning an ESP upstream of a wet FGD has less effect on the outlet emissions and increases the risk of producing off-specification gypsum. According to the commenter, in these cases, the calibration curve for the PM CEMS consists of the normal operating point and an artificial zero.

According to the commenter there is not a lot of documentation available on the installed PM CEMS equipment; however, all of the systems now installed on wet stacks have indicated some plugging problems. The commenter asserts that usually this has been handled by frequent cleaning of the probes. The commenter states that the experience at an EPRI demonstration project has shown similar issues, with some systems working better than others. According to the commenter, all of the vendors continue to make improvements and try alternatives. The commenter states that dry stack systems fare better, especially where cross-stack installations are possible, though one particular model had problems with data loss due to sunlight interference at the height of the day.

According to the commenter, the sensitivity of the PM CEMS is limited by the lowest filterable PM emission that can be accurately and precisely measured by Method 5. The commenter states that in EPRI sponsored PS-11 testing, the lowest range of PM emissions used for calibration was 2 to 5 milligrams per cubic meter (mg/m^3), approximately 0.002 to 0.005 lb/MMBtu. According to the commenter, this level of sensitivity is adequate to measure filterable PM at the proposed total PM limits for existing coal-fired EGUs (0.03 lb/MMBtu), but may not be sensitive enough to measure at the proposed total PM limit for new coal-fired EGUs (approximately 0.005 lb/MMBtu). Commenter notes that while a lower detection limit for Method 5 can be obtained by extending the sampling time, longer sampling times will increase the time required to conduct the full 15 runs required by PS-11.

Response to Comment 30: The final rule no longer requires a PM CEMS for compliance monitoring. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 31: Commenter 19033 is unaware of any PM CEMS that can measure both filterable and condensable PM. The commenter has PM CEMS on three industrial boilers that it owns and operates and they operate at a temperature of approximately 320 ºF, in order to prevent water droplet interference. According to the commenter, if the EPA intends that a PM CEMS be used to assure compliance with the PM limit in Table 2, it needs to amend Table 2 to specify that the PM limit is filterable PM, not total. The commenter states that in that manner, output from a PM CEMS, coupled with the required part 75 flow and diluent monitors, can be used to provide PM emissions on a lb/mm Btu basis. According to the commenter the EPA seems to be trying to control condensable PM by specifying that the PM emission limit be on a total, rather than-filterable basis. The commenter states that wet scrubber technology will provide condensable PM removal, in addition to acid gas removal, and there is thus no need for the EPA to regulate condensable PM as part of this regulation with a specific emission limit.

Response to Comment 31: The final rule no longer requires a PM CEMS for compliance monitoring. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg

HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 32: Commenter 17790 states that the accuracy of a PM CEMS should be considered when setting an emission limit. The commenter states that establishing the "accuracy" of the PM CEMS is accomplished by conducting a three-level Method 5 test but that unlike gaseous monitors (e.g., SO_2 or NO_X CEMS), PM CEMS are not capable of routine calibration checks using calibration gases. According to the commenter, the variability at low PM levels and insufficiency of frequent accuracy checks may impact the reliability and accuracy of the PM monitors reading over time and provide a false indication of compliance or non-compliance with a PM emission limit. Also according to the commenter, PS- 11 certification requirements require de-tuning of PM control devices, without a corresponding relief from current emission limitations and reporting requirements.

Response to Comment 32: The final rule no longer requires a PM CEMS for compliance monitoring. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Although PM CEMS are not required under the final rule, we believe that PM CEMS with a successful correlation using PS-11, with the 95% confidence levels, will assure that the PM CEMS would have the necessary certainty as a compliance monitor. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data.

Comment 33: Commenter 17790 states that the EPA must allow the use of Method 5B to demonstrate compliance with PM limits. The commenter states that Method 5B is allowed for sources calibrating PM CEMs under PS-11. According to the commenter, the method was developed for sources using wet scrubbers and is routinely allowed for compliance stack tests. The commenter states that the EPA did modify some of the requirements in Method 5 (filter temperature) which are consistent with Method 5B objectives and thus should allow the complete use of the method.

Response to Comment 33: PM CEMS are no longer required under the final rule. Method 5 is the reference compliance method in the final rule for the annual PM compliance test. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 34: Commenter 17790 states that there is insufficient reliability in PM CEMS to give accurate data for EGUs with low PM emissions (i.e., EGUs with FGD). The commenter states that its Monroe Power Plant is currently hosting an EPRI PM CEMS Demonstration Project. According to the commenter, the commenter's experience so far suggests that PM CEMS may not be reliable and accurate monitors of stack gas particulates; the project has accumulated limited run time, with sub-standard performance such as plugged monitors and extended down time.

Response to Comment 34: The final rule no longer requires a PM CEMS for compliance monitoring. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Although PM CEMS are no longer required under the final rule, section 2.4 of PS-11 stresses the importance of planning for the specific effluent matrix and/or PM that might influence the correlation and describes the process required to enhance the probability of obtaining a successful correlation and the selection of the most appropriate CEMS for the installation. We believe that PM CEMS with a successful correlation using PS-11, with the 95% confidence levels, will assure that the PM CEMS would have the necessary certainty as a compliance monitor. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data.

Comment 35: Several commenters (17681, 17638, 18831) disagree with using PM CEMS for compliance for the following reasons. According to the commenters:

1. The commenters believe PM CEMS have not proven to be reliable for the electric utility industry,
2. The instruments are very expensive,
3. The instruments measure only filterable PM, and
4. The proposal to use a short-term total PM stack test to establish a continuous 30-day filterable limit does not take into consideration any variability of the reference test method, fuel supply, the CEMS itself or unit operations.

For these reasons, commenters request that the EPA require compliance for metals based on an annual filterable PM test because EGUs are accustomed to conducting annual PM stack tests for SIP and NSPS compliance.

Response to Comment 35: The final rule no longer requires a PM CEMS for compliance monitoring. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Although PM CEMS are no longer required under the final rule, the EPA disagrees with the commenters that indicate a general concern that PM CEMS are not an adequately reliable technology. PM CEMS have been demonstrated for a variety of applications. PM CEMS performance specifications and QA procedures have been around quite a while with PS-11 and Procedure 2 promulgated January 2004. There have been at least 65 successful installations in the United States and in other countries. A successful installation is obtained when a PM CEMS passes the PS-11 statistical criteria, thereby demonstrating that an acceptable level of accuracy is achieved. PS-11 provides the steps in obtaining a reliable successful correlation with reference methods, thereby ensuring compliance data that is sufficient to determine compliance with PM emission limits. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data.

Comment 36: Commenter 19197 states that the PM CEMS operating limit is proposed to be set at the highest 1-hour average measured rate from the most recent performance test used to demonstrate compliance with the total PM emissions limits. According to the commenter, the proposed methodology is likely non-representative because the time period necessary to perform the total PM performance test is relatively short, consisting of three 1- to 2-hour long simultaneous EPA Method 5 and Method 202 stack tests. According to the commenter, the resultant operating limit is only representative of the 3 to 6 hour PM control system operating period and consequently, the performance testing time period may not represent typical PM control efficiencies. The commenter states that the testing might occur during a highly controlled period, resulting in an overly restrictive filterable PM emissions operating limit. The commenter offers an example of the potential subjectivity of the proposal. The commenter states that during performance testing, hypothetical “Facility A’s” baghouse particulate control system’s effectiveness might be very effective and the EPA Method 5 and Method 202 testing show very low filterable and total PM emission rates while conversely, hypothetical “Facility B’s” baghouse particulate control effectiveness might be compromised during the EPA Method 5 and Method 202 performance testing, barely showing compliance with the total PM limit. According to the commenter, consequently, setting the filterable PM CEMS limit as proposed by using the highest 1-hour average measured Method 5 rate during the performance test will penalize the better performing “Facility A.” The commenter states that the PM CEMS limit determination methodology should not encourage operating with marginal baghouse control effectiveness during performance testing.

Response to Comment 36: Under the final rule sources are allowed to establish different operating limits monitored with a PM CPMS if they believe there is variability due to varying load conditions. The final rule no longer requires monitoring with a PM CEMS. The final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). Sources also may opt for quarterly testing with reference methods to determine compliance.

Comment 37: Commenter 17975 states that they have discussed with vendors, the ability of the two primary types of PM CEMS (light scattering or beta measurement) to measure high concentrations of PM, such as are and would be emitted during SSM events, especially for units with non-energized ESPs during such events. The commenter states that vendors have assured the commenter that if the specifications call for measurements of high concentrations of PM then they can supply the appropriate instrument packages. Commenter notes that there is nothing inherently limiting for either of these technologies that would preclude their ability to measure high concentrations of PM and the fact that reputable vendors confirm this makes it imperative that PM CEMS be required at all times, including SSM time periods, when emissions are at their highest, especially for units with ESPs. Commenter provides a short explanation of both types of CEMS.

Response to Comment 37: As mentioned elsewhere, the comment is moot, for the final rule no longer contains emissions limits applicable during startup or shutdown periods and provides for affirmative defense in the event of excess emissions that occur during a malfunction.

Comment 38: Commenter 17696 states that because of bad performance of PM CEMS on two of their coal-fired units, they believe it is inappropriate for the EPA to require the use of PM CEMS for compliance determinations without a reasonable alternative until reliable PM CEMS are commercially available. The commenter believes that a reasonable alternative is to require periodic PM emission tests when fuels change or when PM CEMS indicate, similar to a part 64 CAM approach. The commenter believes it is not necessary to require fuel analyses or bimonthly Method 29 stack tests.

Response to Comment 38: Under the final rule sources are allowed to establish different operating limits monitored with a PM CPMS if they believe there is variability due to varying load conditions. The final rule no longer requires monitoring with a PM CEMS. The final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). Sources also may opt for quarterly testing with reference methods to determine compliance.

Comment 39: Commenter 17705 states that the agency must address issues with PM CEMS technology before mandating its use as a compliance methodology because PM CEMS are not yet widely deployed across the utility industry and because the agency has made use of PM CEMS optional under 40 CFR part 60, subparts D and Da. The commenter has no direct experience with PM CEMS but is aware that the industry has ongoing concerns and states that the EPA shares at least some of these concerns based on text included by the agency in a consent decree that requires a 2-year demonstration period for PM CEMS. According to the commenter the language in the consent decree acknowledges that PM CEMS technology is still in development. The commenter states that the EPA must also commit to providing a simpler and more reliable way to calibrate PM CEMS because PS-11 can be difficult for sources with highly efficient PM controls. The commenter states that the PS-11 procedures place source operators at risk of exceeding permit limits, and the commenter requests that the EPA provide guidance to permitting authorities that it is inappropriate to subject sources to enforcement proceedings when trying to achieve the high dust loads required by PS-11. The commenter does not support the proposed alternative to PM CEMS of conducting bimonthly Method 29 tests.

Response to Comment 39: The final rule no longer requires a PM CEMS for compliance monitoring. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Although PM CEMS are no longer required under the final rule, the EPA disagrees with the commenters that indicate a general concern that PM CEMS are not an adequately reliable technology. PM CEMS have been demonstrated for a variety of applications. PM CEMS performance specifications and QA procedures have been around quite a while with PS-11 and Procedure 2 promulgated January 2004. There have been at least 65 successful installations in the United States and in other countries. A successful installation is obtained when a PM CEMS passes the PS-11 statistical criteria, thereby demonstrating that an acceptable level of accuracy is achieved. PS-11 provides the steps in obtaining a reliable successful correlation with reference methods, thereby ensuring compliance data that is sufficient to determine compliance with PM emission limits. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data.

Comment 40: Multiple commenters (17402, 17681, 17716, 17737, 17758, 17820, 18014) characterize PM CEMS as not measuring PM directly, and several commenters (17402, 17758, 18014) state that PM CEMS calculate PM emissions based on reference method measurements that depend on the calibration procedures and the inherent limitations of the measurement technology.

Response to Comment 40: The final rule no longer requires a PM CEMS for compliance monitoring. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Although PM CEMS are no longer required under the final rule, the EPA disagrees with the commenters that indicate a general concern that PM CEMS are not an adequately reliable technology. PM CEMS have been demonstrated for a variety of applications. PM CEMS performance specifications and QA procedures have been around quite a while with PS-11 and Procedure 2 promulgated January 2004. There have been at least 65 successful installations in the United States and in other countries. A successful installation is obtained when a PM CEMS passes the PS-11 statistical criteria, thereby demonstrating that an acceptable level of accuracy is achieved. PS-11 provides the steps in obtaining a reliable successful correlation with reference methods, thereby ensuring compliance data that is sufficient to determine compliance with PM emission limits. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data.

Comment 41: Multiple commenters (17402, 17716, 17725, 17758, 17790, 17820, 18014, 18498, 18023) believe that PS-11 creates a significant risk of “false positives” due to instrument error because of PS-11’s generous statistical performance criteria. These commenters also express doubts that PM CEMS can produce representative measurements over the entire range of boiler operations because calibration of the instrument does not occur across all load ranges. According to commenters, these periods of operation result in transient flue gas conditions causing changes in particle density, morphology, size distribution or stratification of PM within the flue that are not reflected in the correlation of the instrument. The commenters believe some of the preceding issues can be addressed in the final rule, but the commenters do not think the technology is usable as a direct indicator of compliance as proposed.

Response to Comment 41: Although PM CEMS are no longer required under the final rule, section 2.4 of PS-11 stresses the importance of planning for the specific effluent matrix and/or PM that might influence the correlation and describes the process required to enhance the probability of obtaining a successful correlation and the selection of the most appropriate CEMS for the installation. We believe that PM CEMS with a successful correlation using PS-11, with the 95% confidence levels, will assure that the PM CEMS would have the necessary certainty as a compliance monitor. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data. Applying a technology suitable for a particular application would naturally take some planning. Section 2.4(1) of PS-11 states that you should select a PM CEMS that is appropriate for your source. Manufacturers of beta gauge instruments have demonstrated that the calibration curve does not change as the fuel mix changes or load changes. Vendors have guaranteed that their PM CEMS will meet the PS-11 criteria for multi-fuel boilers. PS-11 provides for situations where multiple correlations may be needed for a PM CEMS technology (see Section 2.3 of PS-11). Based on this information, the final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 42: Several commenters (17402, 17681, 17716, 17740) state that treating PM CEMS as a direct indicator of compliance is inappropriate because the EPA’s floor analysis is based on reference method data, and the proposed limits do not reflect the underlying uncertainty of the PM CEMS.

Response to Comment 42: The final rule no longer requires a PM CEMS for compliance monitoring. Under the final rule, you may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable

PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 43: Commenter 17761 states that if emission reductions are mandated, it must be recognized that PM CEMS have not been widely deployed and their utilization has been largely limited to requirements imposed by the EPA in NSR consent decrees with escape clauses in place. The commenter submits that there is insufficient experience with PM CEMS being utilized for compliance purposes to make them a viable tool to judge compliance with these standards. To the extent that stack testing is an alternative, the commenter submits that there is currently a shortage of qualified stack testers. Due to the level of precision required when conducting such important compliance tests, the commenter has consistently had to waive its procurement guidelines (and pay additional costs) in an effort to obtain quality firms that follow proper procedures after having experiences with failed PM stack test results that are due to human error.

Response to Comment 43: Although PM CEMS are no longer required under the final rule, the EPA disagrees with the commenters that indicate a general concern that PM CEMS are not an adequately reliable technology and are have not been widely deployed. PM CEMS have been demonstrated for a variety of applications. PM CEMS performance specifications and QA procedures have been around quite a while with PS-11 and Procedure 2 promulgated January 2004. There have been at least 65 successful installations in the United States and in other countries. A successful installation is obtained when a PM CEMS passes the PS-11 statistical criteria, thereby demonstrating that an acceptable level of accuracy is achieved. PS-11 provides the steps in obtaining a reliable successful correlation with reference methods, thereby ensuring compliance data that is sufficient to determine compliance with PM emission limits. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data.

Comment 44: Commenter 17871 states that PM CEMS are not yet advanced enough to provide reliable and accurate data at a reasonable cost. The commenter states that state agencies regularly determine that PM CEMS are not reasonably cost-effective monitoring devices-a point with which the EPA has agreed. See 70 FR 7908 (Feb. 16, 2005) (justifying the use of COMS because CEMS are "significantly more expensive to purchase and maintain than COM ..."). The commenter states that the requirement for PM CEMS is particularly problematic for EGUs with very low mass emissions of filterable PM. The commenter states that the MACT requires developing a correlation between the PM CEMS and a reference method (Method 5) using the PS-11, and this involves conducting 15 correlation runs between Method 5 and the PM CEMS over a range of PM concentrations. The commenter asserts that considering the inherent lack of precision of Method 5 at low PM concentrations, it will be very difficult to demonstrate the correlation coefficient (>0.85) required for the initial site specific certification of the PM CEMS. The commenter also asserts that it is also unclear how a range of PM concentrations can be created during performance testing when a fabric filter baghouse is used for particulate control.

Response to Comment 44: Although PM CEMS are no longer required under the final rule, section 2.4 of PS-11 stresses the importance of planning for the specific effluent matrix and/or PM that might influence the correlation and describes the process required to enhance the probability of obtaining a successful correlation and the selection of the most appropriate CEMS for the installation. We believe that PM CEMS with a successful correlation using PS-11, with the 95% confidence levels, will assure that the PM CEMS would have the necessary certainty as a compliance monitor. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and

Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data. Precision of the Method 5 tests may be improved by employing paired trains for each run to sort out the imprecise test runs. PS-11 has a special correlation coefficient of >0.75 for low-emitting sources and section 8.6 of PS-11 allows sources to obtain zero point data to aid in achieving correlation criteria.

Comment 45: Commenter 18447 is concerned about the accuracy and reliability of a PM CEMS and under the proposed rule their units would require monthly stack tests that are excessive and expensive.

Response to Comment 45: Although PM CEMS are no longer required under the final rule, EPA disagrees with the commenters who indicate a general concern that PM CEMS are not an adequately reliable technology. PM CEMS have been demonstrated for a variety of applications. PM CEMS performance specifications and QA procedures have been around quite a while with PS-11 and Procedure 2 promulgated January 2004. There have been at least 65 successful installations in the United States and in other countries. A successful installation is obtained when a PM CEMS passes the PS-11 statistical criteria, thereby demonstrating that an acceptable level of accuracy is achieved. PS-11 provides the steps in obtaining a reliable successful correlation with reference methods, thereby ensuring compliance data that is sufficient to determine compliance with PM emission limits. Most all successful correlations achieve much tighter statistical criteria than the minimum allowed under PS-11 and Procedure 2. Procedure 2 describes the required audits to insure that subsequent measurements are stable and within acceptable limits, thereby ensuring reliable compliance data. Under the final rule we have dropped the requirement for monthly stack tests.

Comment 46: Commenter 18935 recommends that the EPA develop a guidance document for performance specification testing of PM CEMS that reflects recent experience with current control technologies and emission levels. The commenter also suggests that sources be allowed a phase in period for PM CEMS, perhaps allowing sources to conduct frequent periodic monitoring by conventional reference methods until a PM CEMS is installed. According to the commenter, it has assisted clients with the performance specification testing of particulate CEMS and found that many sources have concerns about varying the process or control equipment conditions to produce three varying loads of particulate emissions. The commenter states that sophisticated particulate emission control systems perform consistently and reliably when matched to source characteristics – changing operations to produce alternate emission levels is not an easy matter. According to the commenter, while PS-11 allows for the generation of low level emission data by removing the probe, it is not clear if reference method testing using a Method 5, 5I, or 17 sampling train needs to be conducted during the same time (if so, these methods are not really designed for ambient particulate monitoring).

Response to Comment 46: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-Hg HAP metals. The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11.

6. PM CEMS certification issues.

Comment 47: Commenters 17800 and 17914 request clarification on the procedures to be used for certification of PM CEMS. In order to certify a PM CEMS using PS-11 procedures, the PM CEMS must be correlated using a three point curve with the reference method data. According to the commenters, in order to generate the three PM loads required by PS-11 (section 8.6) it is necessary to partially disable the particulate control device to increase/decrease the PM mass loading to establish a valid correlation curve, but this may not be practical or possible for certain particulate control technologies, as there is no way to temporarily, partially disable fabric filters not equipped with flue gas bypass dampers to generate higher PM emissions. In addition, state the commenters, state or local regulatory permits may preclude a source from operating at PM levels in excess of the permitted levels, and without an exemption, it would not be possible to pass the correlation tests in PS-11. Commenter 17914 states that in addition, for IGCC there is no PM control device since the combustion turbine is burning synthetic gas fuel, and it may not be possible to establish an adequate correlation of PM as per PS-11 requirements for certain control devices/plant configurations.

Comment 48: Commenter 17801 states that PS-11 requires a correlation with reference method tests performed over the full range of the PM CEMS responses that corresponds to the normal operating conditions of the source and control device and that due to a lack of post combustion emissions control, IGCC syngas-fueled turbines are not able to vary PM emissions to achieve a valid correlation. The commenter states that PM spiking is an option (though it hasn't yet been demonstrated and not recommended by GE on a combustion turbine), but these systems are still in development, and may not even be appropriate, safe or possible to inject PM into a combustion turbine. Commenter further notes that PS-11 requires that the confidence interval (CI) and the Tolerance Interval half range (TI) are both calculated as a percent of the emission limit; according to the proposed EGU MACT, the limit would be set by the performance testing for initial compliance and filterable PM is a surrogate for non-Hg metal HAP, and the particulate limit (which includes condensables) would not apply to the correlation; and depending on the results, it may be impossible to meet the specifications using a limit set in this manner. Therefore, states the commenter, compliance with the PM limits should be demonstrated via the standard PM emissions stack testing methodologies (Methods 5/202). The commenter suggests that opacity monitors can be used on a continuous basis as a compliance indicator.

Response to Comments 47 - 48: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-mercury HAP metals. The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11.

Although PM CEMS are no longer required under the final rule, there are several things that help with obtaining a correlation for a low-emitting source. Precision of the Method 5 tests may be improved by employing paired trains for each run to sort out the imprecise test runs. PS-11 has a special correlation coefficient of >0.75 for low-emitting sources and section 8.6 of PS-11 allows sources to obtain zero point data to aid in achieving correlation criteria. We recommend that sources operate their PM CEMS over a correlation test planning period of sufficient duration to identify the full range of operating conditions and PM emissions to be used in your PM CEMS correlation test to avoid operation in excess of the permitted levels. Based on this information, the final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

7. Problems with “floating limits.”

Comment 49: Commenters 17623 and 17774 conclude that the operating limits for PM CEMS will be “floating limits” in which a facility will be measuring filterable particles with its CEMS, but its actual limit is based on the performance testing which measures total PM. According to commenters, as proposed, the “floating limits” will create uncertainty in the regulated community and will be detrimental to the application of the Utility MACT. In light of the measurement problems caused by a total PM limit, one commenter requests that the EPA change the PM surrogate standard from a total PM standard to one based only on filterable PM because the commenter believes it will allow for a clearer target that will not change as operating conditions change.

Response to Comment 49: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals (or HAP metals inclusive of mercury for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 50: Commenters 17714 and 17756 state that under the proposed rule each unit’s operating limit is confirmed or reestablished during subsequent performance tests and this could result in progressively tighter limits over time based on the unit’s most recent test. Commenters believe it is inappropriate and inconsistent with the CAA to tighten a limit based on test results that show lower emissions from a previous test. Commenter 17756 states that their experience with PM CEMS data from well-controlled units show that compliance with a limit established in this way cannot be maintained on a continuous, 30-day rolling average basis and that the proposed total PM limit is unworkable because it fails to provide a single, known standard to be met.

Response to Comment 50: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The establishment of an operational limit is described in the final rule and is applied the same for all sources, thus representing the operation of control equipment for all affected sources. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 51: Several commenters (17655, 17752, 18023) state that PM CEMS operating limits established by unit testing would be unwise and unwarranted because such operating limits could be far below the regulatory limit. According to the commenters it is conceivable that an EGU could meet the total PM performance test standard by a wide margin (e.g., actual Method 5 results during performance test < 0.010 lb PM/MMBtu) but no matter how well the unit performs during performance tests, the proposal stipulates that the unit must continue to operate at the same filterable PM emissions rate (as determined by PM CEMS) indefinitely. The commenters state that the "operating limit" for filterable PM reflects a limit on the only fraction of total PM removed by standard air emission control equipment. Commenter 17655 believes that this is a radical departure from past agency standard-setting, which has consistently recognized that control equipment performance varies over time, especially in units like power generation equipment that must operate for extended periods between maintenance outages. The commenter conjectures that the "EPA apparently assumes that condensable PM is both an indeterminate and widely varying quantity that has the capability of throwing an affected EGU out of compliance…." The commenter contends that the agency offers no evidence that the condensable PM fraction can be determinative of compliance with the non-Hg metals standard, and the commenter believes that condensable PM is instead a relatively fixed increment during normal operation. Based on the commenter's assumption that the condensable PM rate is relatively constant, the commenter recommends that the condensable PM emission rate (lb condensable PM/MMBtu) measured by the reference method in the most recent performance test should be utilized as a constant value in the following equation to determine the hourly emission rate in compliance calculations for the 0.03 lb PM/MMBtu MACT limit for existing sources:

$$\text{Calculated tPM}_{\text{for comparison to standard}} = (\text{cPM}_{\text{from most recent performance test}}) + (\text{fPM}_{\text{from PM CEMS or CAM}})$$

Commenter 17655 concludes that the "operating limit" should not be expressed as being equal to the filterable PM measured during performance tests, but rather the operating limit for sources subject to the total PM limit of 0.03 lb PM/MMBtu should be calculated as follows after each performance test:

$$\text{Operating Limit} = 0.03 \text{ lb tPM/MMBtu} - \text{cPM}_{\text{from most recent performance test}}$$

Comment 52: Commenter 17716 acknowledges that their recommended methodology of determining a filterable operating limit (by subtracting the condensable PM measured during the performance test from the total PM MACT limit) is not without its own flaws, given the bias and uncertainty associated with formation of sulfate and nitrate artifacts in Method 202 (that have nothing to do with metals); however, it does introduce a margin for variability into the compliance process that better reflects normal operating conditions. Commenters 17716 and 17758 also state that establishing a fixed filterable PM operating limit value is necessary for determining the acceptability of the tolerance interval and confidence interval results for PS-11.

Response to Comments 51 - 52: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 53: Commenter 17758 believes without a filterable PM emissions limit in the final rule, the PM CEMS compliance approach is unworkable and inconsistent with the performance criteria of PS-11. Commenter 17716 believes that allowing sources to substitute a total PM limit for a filterable PM limit for PS-11 purposes is appropriate because the total PM limit would effectively represent the highest potential filterable PM limit where condensable emissions are reduced to zero.

Response to Comment 53: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM, using the PM monitoring as a PM CPMS. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Comment 54: Commenters 17912 and 17798 state that the proposed rule that establishes a long-term compliance limitation based upon only a few hours of test results fails to take into account the court's holdings that the EPA must establish MACT standards which include all operating scenarios including variability which always occurs.

Response to Comment 54: The agency disagrees with the commenters, for the PM emissions limit includes a variability component determined using ICR Part II data and the UPL calculation.

Comment 55: Commenters 17913 and 19114 state that the proposed approach punishes a unit that has low PM emissions because the performance test will establish the condensable emissions from each unit, and the subsequent "filterable PM limit" should be equal to the total PM limit in the regulation minus the measured condensable PM emissions. Commenters note that the approach will reward facilities that are able to increase their emissions right up to the total PM limit during the performance test, so as to obtain the least restrictive subsequent "filterable PM limit." According to the commenters, the goal of the regulation should be to ensure that facilities maintain emissions below the given emission standard in the regulation; this is achieved by having a facility demonstrate that filterable PM measured with a CEMS in combination with condensable PM measured during a performance test do not exceed the given total PM emission standard. Commenter 19114 notes that units that employ a baghouse will be out of compliance as often as units equipped with precipitators due to the tighter unit-specific PM limit that would be established as a result of the required performance stack test. For example, states the commenter, a unit equipped with a baghouse may have emissions during the performance testing of 0.008 lb/mmBTU for filterable PM and 0.012 lb/mmBTU for condensable PM thereby passing the performance test; the unit would then have to meet a 0.008 lb/MMBTU limit on its PM CEMS. The commenter states that a unit equipped with an ESP may have emissions during the performance test of 0.02 lb/MMBTU for filterable PM and 0.01 lb/MMBTU for condensable PM, thereby passing the performance test; this unit would then have a 0.02 lb/MMBTU limit on its PM CEMS. The commenter states that the baghouse is doing a much better job of controlling PM, but the manner in which the proposed rule governs ongoing operations does not give the unit with the baghouse credit for its low emissions. According to the commenter, the limits for the baghouse unit should be calculated as the proposed Total PM limit, 0.03 lb/MMBTU, less the condensable fraction, 0.012 lb/MMBTU, to give the source its filterable PM CEMS limit of 0.018 lb/MMBTU; this approach would meet the spirit of the proposed rule by limiting a source to the MACT floor, while giving the source credit for good performance.

Response to Comment 55: Monitoring of total PM is no longer required in the final rule. PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. See the response to Comment 53 above.

Comment 56: Multiple commenters (17655, 17716, 17725, 17752, 17881, 18498, 18023) oppose the proposed procedure for deriving an operating limit based strictly on the filterable PM emission rate during periodic performance tests, and provide the following reasons:

1. According to the commenters, an operational limit equal to filterable PM at the time of testing would reflect an unrealistic expectation of future performance. For example, state the commenters, a fabric filter always performs well for particulate control but, like any other equipment, would be expected to work best when new. It would be unreasonable to hold any equipment to the same level of performance after years of operation (even with frequent maintenance).
2. According to the commenters, the source's margin of compliance may be completely lost depending on the vagaries of the situation at the time of a performance test. According to the commenters, if the combination of normal operating conditions at the time of the performance test enables the unit to operate on the lower end of the normal operating range, the PM operating limit will be unattainably low during operating conditions on the higher end of the normal range. The commenters state that the proposed methodology eliminates the compliance margin for sources with very low emissions on the day of the performance test, yet the opposite result may occur for a unit that barely meets emissions limits due to challenging conditions on the day of the performance test.
3. According to the commenters, the consequence of losing the compliance margin encourages operators to reduce their risk of non-compliance by reverting to a compliance option other than PM CEMS.
4. According to the commenters, the proposed methodology encourages operators to run performance tests on "the ragged edge" of compliance, and the MACT regulations should not encourage operators to conduct compliance tests at sub-optimal conditions. Commenters (18023, 17798, 17912) state that the proposed method provides a disincentive for installing controls, or operating the control in a manner that allows for a reasonable margin of compliance.
5. Commenter 18023 believes the proposed method for establishing a PM CEMS operating limit yields a site-specific limitation that is inconsistent with the MACT program's goal of uniform standards.
6. According to the commenters, an exceedance of the PM CEMS operating limit does not necessarily indicate actual emissions were above the underlying PM standard or non-Hg HAP standard.

Response to Comment 56: The final rule requires the use of a PM CPMS for an operational limit and does not enforce a numeric PM limit. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of Hg for liquid oil-fired units). The operating limit for demonstrating continuous shall be based on the highest 1-hour average measured during the most recent performance test. The source has the option to measure non-Hg HAP metals with a reference method each quarter. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. Any degradation of the control equipment will be accounted for in the yearly reestablishment of the PM operational limit and the compliance margin will change accordingly. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

Under the final rule, sources are allowed to establish different operating limits monitored with a PM CPMS if they believe there is variability due to varying load conditions. The final rule no longer requires monitoring with a PM CEMS. Establishment of the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals using the highest 1-hour average measured, along with allowing more than one operational limit for different load conditions, and a 30-day rolling average should provide certainty of compliance for the source for EGU owners or operators who choose to use a PM CPMS. Should EGU owners or operators choose not to have to develop, monitor, and then maintain the EGUs in accordance with an operating limit, they could choose to use a PM CEMS or quarterly emissions testing.

Comment 57: Commenter 17808 recommends changing the treatment of condensable PM for units using PM CEMS to establish an operating limit on filterable PM. The commenter provides the following example of why the proposed treatment of condensable PM is inequitable with regard to emissions of metals: For instance, states the commenter, in the initial compliance demonstration for Facility A, an existing coal-fired power plant with heat input >8,300 Btu/lb, shows total PM emissions of 0.020 lb/MMBtu with 50 percent filterable and 50 percent condensable PM, a facility-specific filterable PM limit of 0.010 lb/MMBtu would be established. However, states the commenter, an identical Facility B with the same total PM emissions but a higher ratio of filterable PM to condensable PM, such as 75 percent, would establish a filterable PM limit of 0.015 lb/MMBtu. According to the commenter, this method is inherently uncertain, and could result in a facility having a variable emissions target. Additionally, states the commenter, this method results in unfairly “ratcheting down” the standard on some units and introduces a new set of problems.

Response to Comment 57: PM CEMS are no longer required under the final rule. You may elect to comply with an optional operating limit for PM. . See the response to Comment 53.

Comment 58: Commenter 17774 states that the use of a total PM surrogate presents a host of problems including:

1. According to the commenter, the EPA’s use of a condensable PM standard has the effect of increasing the stringency of the PM rate, as compared to an emission rate for PM that applies solely to filterable PM emissions.

2. According to the commenter, the total PM standards are problematic because condensable PM is very difficult to measure and thus proxies must be used for monitoring.

3. According to the commenter, PM CEMS data simply cannot be used to measure compliance in conjunction with a rule imposing a limit on total PM without introducing considerable uncertainty into the compliance guidelines. The commenter states that the CEMS technology is quite different from the formula the EPA used to set the total PM standard. According to the commenter, a PM CEMS monitors only filterable PM emissions, not condensable emissions, and therefore cannot be used to set a total PM limit; because of this, the limits for PM will have to be established by PM performance tests, which are the only process that can measure both filterable and condensable particulates.

4. According to the commenter, the limits for PM do not allow for variability in testing or operating conditions because they are based on the particular circumstances of one stack test. The commenter states that this lack of a variability calculation is contrary to the requirements for setting a MACT standard; if the EPA retains a total PM standard, it must add a variability factor to the requirements to reflect the full range of conditions under which sources are operating. The commenter states that it is not feasible to require numerous stack tests, as each is expensive and time-consuming, nor is it acceptable to base a standard on isolated stack testing conditions alone.

Response to Comment 58: Measurement of condensable PM is no longer required under the rule.

8. Variability of reference method data from scrubbed units.

Comment 59: Commenter 17675 states that stack tests completed since installation of scrubbers indicates filterable PM is very low and that annual condensable PM and filterable PM test data indicates there are no consistent ratios for condensable PM, filterable PM, or total PM from the commenter's scrubbed units. Based on these highly variable and consistently low PM data, the commenter believes it will be nearly impossible to develop an accurate correlation curve for PM CEMS. In lieu of the PM CEMS option, the commenter requests that the final rule include an LEE testing option for sources consistently performing at emission rates much lower than the PM standard. The commenter requests that such a PM LEE option preclude regular or additional Method 29 tests.

Response to Comment 59: Measurement of condensable PM is no longer required under the new rule. The final rule does include the LEE option with less frequent performance testing.

Comment 60: Commenters 17383 and 19121 state that trying to use a PM CEMS that was designed to measure filterable PM for measuring total PM is questionable at best and that based on the commenter's limited testing, the ratio of condensable PM to filterable PM is highly variable. According to the commenters, under these circumstances, correlation of the PM monitor would be difficult if not impossible. Commenter 19121 states that the inclusion of condensable PM fractions in the limit hints at trying to control $PM_{2.5}$ precursors, which is better managed under another CAA program.

Response to Comment 60: Measurement of condensable PM is no longer required under the new rule. PM CEMS are no longer required in the final rule.

Comment 61: Commenter 18443 states that the EPA cannot require sources to set filterable PM operating limits with no compliance margin and that for units that emit low concentrations of PM, this is an extremely onerous requirement with which it is likely impossible to comply. Units with wet FGDs, for example, typically emit filterable PM at or below detection levels. According to the commenter, a limit set at these levels would be below the detection level of a PM CEMS and allow no compliance margin. The commenter states that the EPA has not justified this type of requirement and it must be eliminated from the final rule.

Response to Comment 61: PM CEMS are no longer required in the final rule. PM CPMS should be able to operate at the low PM operational levels expected at sources and should not be below the detection limits.

9. Need for PM CEMS availability criteria.

Comment 62: Commenters 17638 and 17681 state that the EPA must establish minimum CEMS data availability and deviation requirements and that the operating costs included in the proposal fail to account for all the maintenance costs associated with PM CEMS. One commenter requests that the EPA revise those operating cost estimates.

Response to Comment 62: PM CEMS are no longer required in the final rule.

10. Table 4 requirement to convert PM CEMS readings to dry basis.

Comment 63: Several commenters (17716, 17725, 18014) advise that the requirement in Table 4 of the proposed rule to convert PM CEMS data to a "mg/ dscm" basis creates unnecessary problems because most PM CEMS do not measure on a dry basis but are correlated to "mg/wscm." According to the commenters, switching to a mg/dscm is problematic because the current measurement must be converted to a dry basis which would require a source to monitor stack moisture or use a some type of default value. Notwithstanding the inadvisability of using the PM measured during the compliance test as an operating limit, state the commenters, if the final rule retains this provision, sources should be allowed to use either the average 30-day correlated analyzer response (mg/wacm, mg/wscm, etc.) or lb/MMBtu values as an indicator.

Comment 64: Commenter 17881 states that under section 63.10021(a)(11)(ii) diluent data (O_2/CO_2) is only needed for the lb/MMBtu rate calculation or concentration values corrected back to a diluents gas concentration (which is not the case, as the PM filterable operating limit is mg/dscm and is not corrected back to a specific diluent level).

Response to Comments 63 - 64: PM CEMS are no longer required under the final rule. PM CPMS measurement data are to be in units of raw instrument output and not necessarily on a concentration basis in the final rule. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

11. ESPs vs. fabric filters.

Comment 65: Commenter 17705 has concerns because while ESPs are highly effective control technologies, they may not be as consistent in its day-to-day performance as fabric filter technology. According to the commenter, this difference is not a problem at currently permitted PM limits and under current compliance demonstration requirements (i.e., annual performance testing), but it could be a significant problem if the EPA retains the currently proposed requirements to establish PM operating limits, as such operating limits are expected to allow little, if any, operational variability in control equipment. The commenter doubts that even utilities with EGUs equipped with fabric filters can be confident they can demonstrate continuous compliance if the PM operating limit requirement is implemented as proposed by the EPA.

Response to Comment 65: While the rule no longer requires use of PM CEMS and associated operational limits, the rule retains establishing an operational limit and measuring it using a PM CPMS. Should the owner or operator be uncomfortable with using a PM CPMS and an operating limit, the final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). The source can also conduct quarterly performance testing in place of these continuous monitoring options.

12. Direct measurement.

Comment 66: Commenter 17747 states that direct monitoring of pollutants rather than a surrogate (PM) will contribute to a better understanding of the health effects associated with each metal. According to the commenter, direct measurement for HAP by the EPA is a provision of the CAA Revisions of 1990 and best fit with the requirements and purpose of the law.

Response to Comment 66: Consistent with the CAA, the rule requires monitoring sufficient to assure compliance with the emissions limits and that the sources will maintain emissions reductions on a continuous basis. The rule applies continuous emissions monitoring effectively with a focus on the HAP

(Hg) of interest and allows for other monitoring in a manner consistent with the CAA. We also believe that implementing this rule with the required frequent testing, including HAP metals, and continuous emissions monitoring will provide a significant increase in the amount of directly measured emissions data over the current database. The rule also requires electronic reporting of monitoring and testing data directly to the EPA so that we will have these data in hand for supporting subsequent regulatory reviews.

Comment 67: Commenter 17881 states that it makes little sense to have sections 63.10005(d)(1) through (d)(6), as well as section 63.10005(e), describe the averaging of hourly "concentrations" obtained using a CMS during an initial 30-day period when the emission standards are always expressed as emission rates (in units of lb/MMBtu, lb/TBtu, lb/MWh or lb/GWh). Commenter further notes that section 63.10005(d)(5) currently discusses the use of PM CEMS for demonstrating compliance with the applicable emission limits in Tables 1 and 2 of the proposed rule but that the reference to the use of PM CEMS for demonstrating compliance with the emission limits is wholly inappropriate, as the PM CEMS are to be used to verify compliance with an operating limit (in units of mg/dscm) consistent with Table 4 of the proposed rule, not PM emission limits expressed as lb/MMBtu or lb/MWh (and reckoned on a different basis, i.e., total PM versus filterable PM).

Response to Comment 67: We have edited the final rule so that the text is consistent with the format of the required measurements. Note also that measurement of condensable PM is not required in the final rule and PM CEMS are no longer required in the final rule. The final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion).

13. Clarification on use of parametric monitoring in lieu of CEMS.

Comment 68: Commenter 17914 requests clarification on the parametric monitoring approach described on page 25064. The commenter finds only an annual test requirement for the Parametric Monitoring option. The commenter notes that in the preamble (pages 25029 -31) both initial compliance and on-going compliance for IGCC or coal or solid oil-derived fuels requirements are discussed and if an EGU elects to use total PM as a surrogate for non-Hg HAPS, they must use a PM CEMS. The commenter states that an EGU may:

- Install PM CEMS and reduce the level of testing regardless of type of control equipment status

- Demonstrate compliance by testing every month if no controls are installed and no continuous PM monitoring is done

- Demonstrate compliance by testing every 2 months if controls are installed and specific control equipment parameters are monitored with PM CEMS

The commenter states that any EGU can, as an alternate to testing, install PM CEMS. According to the commenter it is unclear in the body of the proposed rule what testing beyond an annual compliance test may be required for the parametric monitoring option, and there is no evidence provided by the EPA to suggest why a parametric monitoring approach would require additional testing beyond that required for PM CEMS. According to the commenter, it would be expected that a change in coal characteristics, combustion system operation or AQCS system performance may cause the parametric correlation to PM emissions to change but it is not clear why a PM CEMS would be immune to this same effect. According to the commenter, the use of PM CEMS requires use of a quasi-parametric relationship with filterable particulate since the PM CEMS signal must be correlated to the reference method, for example

EPA Method 5 or Method 17. The commenter states that these correlations can change over time and with varying conditions. Monthly variation of PM emissions vs. system operating parameters requires additional study to determine if any variation exists that may result in exceedance of the total PM limit. The commenter states that this study should also include PM CEMS and the potentially variable relationship of filterable PM to Total PM over time. The commenter recommends the proposed rule be revised to reduce the testing requirements when using the parametric monitoring to an annual test or less often when it is proven that PM emissions are < 75% of the MACT limit in line with the final Industrial boiler MACT (subpart DDDDD) regulations. The commenter further recommends that the text in section 63.1 0022 explicitly include wet ESP technology in the parametric monitoring options for PM.

Response to Comment 68: Measurement of condensable PM is not required in the final rule. PM CEMS are no longer required in the final rule. If you use a PM CPMS, you must conduct annual testing to assess the operating limit (expressed in the raw output of the PM CPMS) established during the previous test.

Comment 69: Commenter 19033 recommends that the operating requirements for ESP power input, as documented during performance tests, only be applicable during periods of PM CEMS downtime, so that it can be demonstrated that the ESP is operating properly during such PM CEMS downtime events. The commenter states that such a provision would be patterned after the Part 75 requirements that address demonstration that the APCD is operating properly, so that SO_2 substitution values can be supported during periods of SO_2 CEMS downtime.

Response to Comment 69: Parameter monitoring of ESP parameters is not required in the final rule.

Comment 70: Commenter 19121 states that units with PM CEMS should not be required to install bag leak detectors.

Response to Comment 70: Parameter monitoring of baghouses, including bag leak detectors, is not required in the final rule.

14. Corrections.

Comment 71: Commenter 18014 states that Table 8 erroneously references “QA Procedure 5” for the PM CEMS QA/QC requirements. According to the commenter, this reference should be changed to “Procedure 2.”

Response to Comment 71: This reference has been removed in the final rule.

Comment 72: Commenter 19121 states that part 63 Table 4 is setting operating limit averaging periods of 1 hour for outlet emissions is counter to the 30 boiler operating day averaging methodology.

Response to Comment 72: The final rule requires a 30-boiler operating day rolling average for the PM CPMS monitoring.

Comment 73: Commenter 17881 states that the PM CEMS should not be subject to the quality assurance tests required under section 63.10021 (a)(11)(iv) because filterable PM is not the regulated pollutant and correlation testing will dictate operating in an abnormal manner for purposes of obtaining three different PM levels. Commenter notes that this applies also to (a)(16)(vii) and (a)(17)).

Response to Comment 73: The final rule does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit in the final rule if the source elects to use this approach (see the final preamble for further discussion). If this option is used, the source must comply with the QA requirements in PS 11. However, PM CEMS are not required in the final rule. If the source uses the monitoring as a PM CPMS to demonstrate compliance with an operating limit, then the provisions of PS 11 do not apply, and the applicable QA/QC provisions will be as set forth in the monitoring plan required in the final rule.

Comment 74: Several commenters (19536, 19537, 19538) state the compliance provisions specify periodic performance testing in which the surrogate, regulated pollutants, and operating parameters are monitored for two cases: (1) no PM CEMS with PM controls and (2) no PM CEMS with no PM controls. The commenters state that if a PM CEMS is used, regardless of whether the units is equipped with PM controls, no operational or non-Hg metal HAP monitoring is required except during an every 5-year performance test and that this is inadequate to determine continuous compliance. Further, it does not provide any testing for metals present as gases or condensables. Thus, state the commenters, HAP such as selenium, which the EPA admits is frequently present in the gases, would not be measured either directly with Method 29 or indirectly through a surrogate when PM CEMS is used to determine compliance. The commenters also state that initial performance compliance provisions are missing from Table 5 for PM CEMS.

Response to Comment 74: You may elect to comply with an optional operating limit for PM. If you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or HAP metals inclusive of mercury for liquid oil-fired units). The operating limit for demonstrating continuous compliance shall be based on the highest 1-hour average measured during the most recent performance test. If you use a PM CPMS and associated operating limit, you must conduct the applicable Method 5 or Method 29 test once annually and re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11.

15. Five-year test requirement.

Comment 75: Commenter 17798 states that stack testing once every 5 years to corroborate CEMS monitoring is a very long time period to rely on CEMS filterable PM data which may or may not relate to actual metals emissions. Therefore, the commenter feels this monitoring approach is overly complex, requires expensive CEMS monitoring, and may not demonstrate real metals emission levels for up to 5 years. The commenter requests that the EPA consider the following modifications: With the CEMS monitoring option, require stack testing every 2 years instead of 5 years to establish compliance with metal emission limits relative to filterable PM emissions. The commenter states that using a CEMS approach is premised on the EPA's ability to establish a relationship between filterable PM and metals emissions on a sector-wide basis and sources with particular control equipment may require adjustments to this method to account for wet conditions from wet scrubbers. The commenter asserts that under a CEMS monitoring approach the EPA should eliminate any requirement for testing and setting of pollution control equipment operating parameters.

Response to Comment 75: The comment is moot, as the rule does not require use of PM CEMS; PM CPMS are an alternative and annual testing is required to reassess the operating parameter value. For those owners or operators who choose to use PM CEMS as an alternative, no additional operating parameter value monitoring or limit is necessary. Furthermore, in that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11.

Comment 76: Commenter 17800 asserts that the EPA has not explained why there should be an independent filterable PM limitation that changes every 5 years. According to the commenter, although it is reasonable to retest for compliance every 5 years because of the innate variability of unit operation resetting emission limitation is not.

Response to Comment 76: The comment is moot, as the rule does not require the use of PM CEMS and PM emissions testing every 5 years. Where a source uses a PM CPMS as part of its monitoring approach, annual testing is required to reassess the operating parameter value.

16. PM as surrogate Method 202.

Comment 77: Commenter 19114 states that using total PM as a surrogate has numerous technical challenges that demonstrating continuous compliance using a filterable PM limit does not. The commenter states that filterable PM can be measured continuously through a PM CEMS monitor. According to the commenter, the variability of condensable PM in the flue gas is enormous and the test methods for condensable PM are still incapable of accurately measuring the condensate in a replicable fashion routinely. The commenter states that the study that the commenter conducted, in conjunction with EPRI, showed that the Method 202 may not be accurate in stacks with FGD. The commenter states that more study is required to understand the limitations with the measurement of condensables and to construct a test method that will be accurate and repeatable for in-stack measurements.

Response to Comment 77: While the agency disagrees with the suggestion that Method 202 is "incapable of accurately measuring the condensate in a replicable fashion routinely," the comment is moot, as the final rule does not contain a total PM emissions limit.

17. Miscellaneous.

Comment 78: Commenter 17800 states that under section 63.10010(g)(3) the EPA is requiring a PM CEMS to "complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period." According to the commenter, depending on the PM CEMS used and the level of particulate emitted this may not be possible. For example, states the commenter, a system that uses a filter tape (dichotomous sampler) to measure filterable PM where there is very low filterable PM levels emitted (similar to the proposed PM standard) may not be able to collect enough sample to adequately measure these emissions in this 15 minute timeframe. The commenter states that the EPA should allow some flexibility in this requirement to allow for monitoring extremely low levels of filterable PM emissions.

Response to Comment 78: Measurement of condensable PM is not required in the final rule. PM CEMS are not required in the final rule.

Comment 79: Commenter 17752 questions, with respect to PS 11, whether it is possible to create or measure two PM levels between zero and the levels anticipated in the rule.

Response to Comment 79: The rule now includes an option for using PM CPMS, whose use should alleviate the commenter's concerns, as well as maintains the option for using PM CEMS. Note that other compliance options exist should an EGU owner or operator choose not to use PM CPMS or PM CEMS.

Comment 80: Commenter 17752 suggests that PM CEMS could be used as an "indicator of compliance" for an "appropriate" filterable PM limit, to identify when investigation and corrective action are warranted.

Response to Comment 80: The comment is moot, for while the rule maintains the use of PM CEMS as a compliance demonstration option, the final rule also allows the use of PM CPMS, which involves establishing and maintaining a site-specific operating limit as an indicator of compliance, as another compliance demonstration option.

Comment 81: Commenters 17724 and 17876 state that the CEMS the facility installed in preparation to CAMR have significant reliability and operational issues (Hg, PM, HCl). Commenters 17724 and 17876 state that the EPA has left the long-term operational problems such as calibration gases to industry and there are not accurate and reliable monitoring methodologies for demonstrating. Commenters 17724 and 17876 state the EPA purports to provide compliance flexibility while in reality there is very little flexibility in light of the problematic and unproven nature of these monitoring technologies.

Commenter 17736 states the EPA cannot rely on unproven HCl CEMS, that HCl CEMS are not commercially available to measure HCl emissions from coal-fired EGUs, and no HCl CEMS were used to collect the data the EPA used to establish the HCl standard.

Response to Comment 81: The agency disagrees with the commenters. As mentioned elsewhere, the agency finds that the operation and maintenance issues for the CEMS mentioned are no different than for other CEMS now in wide use and acceptance by the industry. The agency is aware that the calibration gas issue is to be rectified well in advance of the rule's compliance date. The agency notes that the rule is quite flexible with respect to compliance demonstration, containing numerous choices for compliance, including the use of emissions testing alternatives for those EGU owners or operators who remain concerned over use of CEMS or PM CPMS. The agency notes that FTIR CEMS exist now and can be used to measure HCl emissions continuously, that the HCl emissions limit was developed from emissions testing and has been adjusted to be appropriate for measurement with HCl CEMS, and that emissions testing options to demonstrate compliance exist for those EGU owners or operators who choose not to use CEMS.

5A07b - Testing/Monitoring: Application of multi-metals CEMS

Commenters: 17283, 17747, 19536, 19537, 19538

1. In favor of multi-metals CEMS.

Comment 1: Commenter 17283 recommends that multi-metal CEMS should be an allowed alternative for demonstrating compliance with the EPA proposed metals emissions limits. The commenter states that this recommendation is based on the proven performance and commercial availability of multi-metal CEMS, the fact that multi-metal CEMS represent substantially enhanced monitoring and PM is not an appropriate surrogate for HAP metals emissions in an increasingly complex energy extraction process.

Response to Comment 1: In the final rule, facilities would be allowed to petition the Administrator under section 63.8(f) of subpart A of part 63for an alternative to use of multi-metal CEMS at a specific site in lieu of required monitoring in the final rule. Also see responses to comments under Comment Code 4F01 for further discussion of relationship of PM and non-Hg metal HAP.

Comment 2: Commenter 17747 states that multi-metals CEMS represent the highest level of monitoring for these sources (i.e., directly monitoring the HAP pollutant of concern on a continuous basis).

Response to Comment 2: Short term multi-metal CEMS demonstrations have historically shown, with appropriate QA/QC, that the data are accurate and reliable. Longer term operational information would be needed to support a proposal of performance specifications. We agree with the commenter that data from multi-metal CEMS is a direct measurement of metals and not a surrogate measurement.

Comment 3: Commenter 17747 asks that the EPA incorporate language in the final rule expressly allowing the use multi-metals CEMS once a multi-metals performance specification has been promulgated. According to the commenter, the incorporation of this type language would give source operators some assurance that monitoring with a multi-metals CEMS would be acceptable to the EPA, and it is also likely to encourage the use of multi-metal CEMS on sources, which is beneficial to the EPA's understanding of the health effects associated with metal HAP. Finally, states the commenter, multi-metal CEMS would provide source operators with more feedback on control of metals and may allow them to optimize operations to minimize HAP metal emissions. The commenter provided information about the capabilities of their proprietary testing technology.

Response to Comment 3: We may in the future propose a multi-metal performance specification and QA/QC requirements but we have no immediate plans to do so because we lack long term operational information and the resources to support a proposal. The final rule does reiterate the ability of a source to petition the Administrator under section 63.8(f) of subpart A of part 63for an alternative to use multi-metal CEMS at a specific site in lieu of required monitoring in the final rule. The EPA does have a draft method on its website at www.epa.gov/ttn/emc that could be the basis of a petition to the Administrator for alternative monitoring. We agree that multi-metal CEMS could possibly provide source operators with more feedback on control of metals and may allow them to optimize operations to minimize HAP metal emissions.

Comment 4: Commenter 17283 states that direct monitoring of all phases of all HAP metals is an enhancement over the monitoring of a surrogate (PM) for some urban HAP metals. According to the commenter, periodic testing does not provide reasonable assurance of control/prevention nor does monitoring PM provide reasonable assurance of urban HAP metal control/prevention, and multi-metals CEMS is commercially available and accepted by the EPA. Thus, states the commenter, use of PM as a surrogate for HAP metals monitoring is no longer needed.

Response to Comment 4: We believe that the final rule does provide a reasonable assurance of compliance with the non-Hg metals limitation and the monitoring and testing that we are requiring are consistent with numerous EPA rulemakings for comparable emission sources. We are providing for monitoring continuous compliance with specific standards through the use of an applicable CEMS, or a sorbent trap for Hg, or a PM CPMS for non-Hg metals or PM. Should a source owner or operator elect not to use CEMS or the other instrumental methods, performance testing is required.

2. Individual metals.

Comment 5: Commenter 17283 states that monitoring only the vapor phase of Hg does not provide reasonable assurance of control/prevention under all conditions that are now to include SSM events. The commenter states that this is particularly the case when there is a proven and approved technology available that measures all phases of Hg. The commenter recommends the use of multi-metal CEMS as an alternative to Hg CEMS.

Comment 6: Commenter 17283 states that selenium does not meet two of the three court-defined criteria which must be met for PM to be a surrogate for HAP metals: "…HAP metals are invariably present in cement kiln PM…" (subsection 3.2.1); and "…PM control technology indiscriminately captures HAP metals along with other particulates." (subsection 3.2.2.) According to the commenter, the addition of a condensable fraction to the definition of PM only complicates this for other HAP metals.

Response to Comments 5 and 6: Note that the final rule no longer applies a numerical emissions limit during startup and shutdown much reducing concerns about limited measurement of particulate Hg. The EPA disagrees that selenium does not meet two of the criteria which must be met for PM to be a surrogate. Selenium is a metalloid that sits just below sulfur on the periodic table and is, chemically, very similar to sulfur. In the high temperature combustion environment, selenium is likely to be present as gas phase SeO_2 (as, similarly, sulfur is likely to be present as gaseous SO_2). Much like SO_2, SeO_2 is a weak acid gas. The ash from western subbituminous and lignite coals contains natural alkalinity (in the form of Ca or Na compounds). The alkaline compounds in the fly ash effectively neutralize the SeO_2 acid gas, forming a particulate that is easily removed in the PM control device. Eastern bituminous coals typically contain insufficient free Ca to completely neutralize the SeO_2 and the much increased levels of SO_2 in that flue gas. However, because SeO_2 behaves very similarly to its sulfur analog, SO_2, it can be expected to also be removed effectively in standard FGD technologies (wet scrubbers, dry scrubbers, DSI, etc.). Therefore, selenium will either fall in to the category of ‘‘non-Hg metal HAP’’ and be effectively removed in a PM control device, or it will fall into the category of ‘‘acid gas HAP’’ as gaseous SeO_2 and be effectively removed using FGD technologies. We specifically reviewed the Method 29 data from the utility boiler ICR where we had measured particulate emissions, selenium emissions and selenium in the coal. In almost 90 percent of the facilities less than half of the estimated selenium was emitted. In the remaining facilities, we reviewed the location where selenium was collected in the Method 29 sampling train and found measureable amounts of selenium on the quartz filter. While we do not know the amount of selenium that was in the flue gas prior to any emissions control, we conclude that selenium was available in particulate form after emissions controls and was likely removed by the particulate and/or acid gas controls.

3. Concerns about use of PM as a surrogate.

Comment 7: Commenter 17283 states that reducing HAP metal concentrations from their current levels in feed and fuel to zero would essentially reduce HAP metals to zero in the emissions (reducing HAP metals concentrations by many orders of magnitude) while having essentially no impact on PM emissions. According to the commenter, processes and additives may increase PM emissions without increasing HAP metal emissions, such as might be the case of scrubber solution bypassing demisters, or they may increase HAP metal emissions without increasing PM, such as might be the case if trace HAP metal concentrations increase in an additive or other feed material, or where an additive is injected into the process. The commenter states that without the direct monitoring of HAP metals, there will be no way to determine if the HAP metals are changing.

Response to Comment 7: While modifying the feed and fuel such that the HAP metal concentrations are zero would achieve essentially zero emissions, the EPA knows of no techniques which could achieve this end without transferring the emissions to another source. Also see responses to comments under Comment Code 4F01 for further discussion of relationship of PM and HAP metals.

Comment 8: Commenter 17283 states that Method 29 is costly, dangerous, creates hazardous waste and is difficult to obtain accurate and reliable results at the low concentration expected with contemporary controls. The commenter states that in effect, it appears that the EPA is using PM as an indicator or parameter to monitor in much the same way they use plant operating parameters in CPMS. According to the commenter, as long as PM, fuel, and all control parameters remain relatively constant between Method 29 measurements, one might be able to assume that HAP metals emissions have not changed dramatically since the last Method measurement, but it would be far less costly, far more informative and protective as well as more useful for plant operation if a multi-metals CEMS were used to measure HAP metals emissions directly and continuously.

Response to Comment 8: The EPA disagrees with the commenter's opinion about EPA Method 29. We have found the method to provide reliable, low level, repeatable results when properly conducted in the field. The cost of using this method is actually much more economical, per analyte than many other test methods that the EPA employs to measure emissions.

Comment 9: Several commenters (19536, 19537, 19538) state that total PM is not an appropriate surrogate for non-Hg metal HAP and those HAP can be accurately measured by CEMS. According to the commenter, if the EPA retains total PM as a surrogate, a PM CEMS should be required, not optional, to determine compliance. The commenter states that PM CEMS have been required in consent decrees and PSD permits to determine compliance and are in wide use at EGUs.

Response to Comment 9: The final rule uses a filterable PM surrogate limit for non-Hg metal HAP, with the required compliance testing using a manual PM method. The EPA also established an alternate equivalent standard for non-Hg metal HAPs, but the on-going monitoring with these metals is accomplished with a PM CPMS for an operational limit or frequent testing with a metals manual method. Also see responses to comments in 4F01 of this document for further discussion of relationship of PM and HAP metals. Furthermore, the final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11.

5A08 - Testing/Monitoring: Application of SO_2 CEMS

Commenters: 17191, 17383, 17621, 17677, 17722, 17725, 17728, 17730, 17752, 17758, 17775, 17790, 17800, 17820, 17821, 17868, 17873, 17881, 17886, 17902, 17909, 18014, 18037, 18428, 18498, 18539, 19120, 19536, 19537, 19538, 18023

1. Allow existing IGCC units to use SO_2 CEMS option.

Comment 1: Commenter 17191 believes it is appropriate for the EPA to include the SO_2 monitoring option in Table 2, part 3b as an alternative to monitoring HCl. The commenter notes in response to the EPA statements in the preamble regarding a lack of data on SO_2 monitoring for existing IGCCs, that SO_2 CEMS monitoring data for its IGCC unit are routinely submitted electronically to the EPA and the EPA has ready access to the CEMS data as they are publically accessible and have been used previously in the rulemaking for the Transport Rule (aka Cross-State Air Pollution Rule). The commenter stresses the importance of the SO_2 monitoring as an option, given the current lack of a PS specific to HCl CEMS, as described in the proposed rule preamble. The commenter believes that it is in the best interest of it cooperative members to be able to rely on existing SO_2 monitors for acid gas compliance rather than incurring the cost of installing HCl monitors that have little or no long-term demonstrated “real world” reliability. The commenter requests that the SO_2 CEMS monitoring option be included for the existing IGCCs as a matter of equity and fairness. As these data are readily available to the EPA and interested public, there is no basis for the EPA’s preamble justification for not including the option. While the commenter specifically references their IGCC unit, they do note that it is one of only two IGCC EGUs currently operating that are included in the existing IGCC category established by the proposed regulation.

Commenter 17191 requests that section 63.9991 be rewritten to eliminate the pre-requisite of using a wet or dry FGD technology to qualify for the alternate SO_2 CEMS limit. The commenter notes that their IGCC system uses a sulfur removal system upstream of the combustion of the syngas; the removed sulfur is captured and sold as molten sulfur for reuse. According to the commenter, as the sulfur is removed prior to combustion no FGD technology is required for IGCC emissions. The commenter believes this Clean Coal Technology should not be penalized (prevented from opting to use SO_2 monitors) because it uses an upstream technology for sulfur removal, eliminating the need to treat the flue gas for SO2 removal.

The commenter attempted to find the provisions in the regulation that need to be amended so that existing IGCC units can rely on the option of SO2 CEMS use. The commenter requests that the EPA amend other sections of the regulation, as necessary, which may have been overlooked or that may be subject to revision before final rule issuance that would prohibit existing IGCC SO_2 CEM use.

The commenter suggests the following modifications to section 63.9991:

> *“(a)(l)(i) You man not use the alternate SO_2 limit if your coal-fired EGU does not have* ***a system for pre-combustion sulfur removal or*** *a system using wet or dry flue gas desulfurization technology installed on the unit.* “ (Emphasis reflects proposed inserted change).

> *“(a)(l)(ii) You may not use the alternate SO_2 limit if your oil-fired EGU does not have* ***a system for pre-combustion sulfur removal or*** *a system using wet or dry flue gas*

desulfurization technology installed on the unit. " (Emphasis reflects proposed inserted change).

"(a)(l)(iii) You must operate the ***pre-combustion sulfur removal system, or*** *the wet or dry flue gas desulfurization technology installed on the unit at all times in order to qualify to use the alternated SO_2 limit.* " (Emphasis reflects proposed inserted change).

The commenter also requests that section 63.10000(c)(1) be amended, in part, to read:

"As another alternative to HCl CEMS, you may demonstrate initial and continuous compliance through use of a certified sulfur dioxide (SO_2) CEMS, provided the unit has ***a system for pre-combustion sulfur removal or*** *a system using wet or dry flue gas desulfurization technology.* " (Emphasis reflects proposed inserted change).

Comment 2: Commenter 17758 suggests SO_2 CEMS should be allowed to be used as a surrogate for HCl for IGCC units since FGD is not needed for those units and HCl CEMS are not a proven compliance monitoring technology. The commenter believes such details need to be clearly defined in the final rule.

Response to Comments 1 - 2: The EPA disagrees with the commenters' suggestions First, the premise upon which the rule allows for SO_2 monitoring in lieu of HCl monitoring of the exhaust of a wet or dry FGD unit is that the FGD preferentially removes HCl over SO_2. That means that SO_2 control is a certain indicator of similar or better HCl control when the control measure is a wet or dry FGD. We are not aware that other sulfur control measures including pre-control sulfur removal can be related to similar HCl emissions reduction. Further, the rulemaking record does not have any SO_2 data from existing IGCC units to correlate with HCl emissions. The SO_2 data pne commenter references are not data collected as part of establishing the HCl standards under this rule. As noted by the commenter, the unit in question appears not to use a wet or dry FGD, which is a prerequisite for using SO_2 as an indicator of HCl control. The preamble to the proposed rule fully explains the rationale for this limitation.

2. SO_2 CEMS certification.

Comment 3: Commenter 17677 states that section 63.10010(e) creates some confusion about certification of SO_2 CEMS. The commenter believes the proposed rule should simply allow CEMS certified under 40 CFR 75 or 40 CFR 60 to be acceptable.

Response to Comment 3: The EPA disagrees as the specific provisions in section 63.10010(e) add specific requirements to the general part 60 and part 75 requirements. Note that the EPA believes part of the commenter's confusion results from a typographical error in cross referencing paragraph (g) of the section. All of those cross references should be to paragraph (e), not (g), and are corrected in the final rule.

Comment 4: Commenter 17402 objects to the linearity test requirement for SO_2 monitoring. The commenter states that section 63.10010(e)(6)(ii) of the proposed regulations states that one "must perform the linearity check test required in Appendix A to part 75 on the SO_2 CEMS whether or not it has a span of 30 ppm or less." According to the commenter, this requirement ignores the EPA's previous acknowledgement that a linearity check "begins to lose its significance" at span values less than or equal to 30 ppm. The commenter states that in the preamble to the proposed 1998 revisions to 40 CFR Part 75, the EPA acknowledged that span at these low values loses its significance. The commenter believes the proposed requirements should be replaced with the Part 75 exemption. According to the commenter part 75 requires EGUs to ensure that the analyzer span is set to obtain accurate and representative data. Part 75 also requires the owner or operator of an EGU to conduct an annual analyzer span and range evaluation to ensure that the majority of the analyzer readings are within 20 to 80% of span. According to the commenter, coupled with these requirements, the three linearity gas concentrations are more than sufficient to determine that the analyzer is linear. The commenter states that the proposed linearity requirement will add significant costs.

Response to Comment 4: The final rule has been amended to remove the fourth gas nominally near the emission standard level. The EPA disagrees that a linearity check is unnecessary to ensure quality assurance of the SO_2 CEMs for compliance at emission standard levels.

Comment 5: Commenter 17758 states that it is confusing why, despite using continuous SO_2 monitors successfully for more than 20 years, the EPA has proposed additional QA requirements. The commenter states that in proposed section 63.10010(e)(6) the EPA has added several problematic additional QA requirements for SO_2 CEMS that are not currently specified in Appendices A or B of 40 CFR part 75.

The commenter notes the following:

- Section 63.10010(e)(6)(i) – According to the commenter, the proposed Utility MACT rule would require the SO_2 CEMS to pass a 7-day calibration error test for units with spans less than or equal to 50 ppm and it is unclear whether the specifications in Part 75 or PS 2 are applicable. According to the commenter, under Part 75 requirements, the 7-day calibration error specification is a difference of less than or equal to 2.5 percent of span or ±5 ppm; using the Part 75 specifications, current SO_2 CEMS should be able to easily meet the alternative ±5 ppm requirement. The commenter states that if the PS 2 specifications are to be applied, then the specification is restricted only to the drift requirement of 2.5 percent of span, and this will make passing the 7-day calibration error test significantly more burdensome. According to the commenter regardless of which specification is used, neither will improve the overall quality or accuracy of the collected data, since these are only implemented for initial certification or recertification events; in other words, there is little a utility can do to upgrade its SO_2 CEMS to meet this requirement.
- Section 63.10010(e)(6)(ii) – According to the commenter, the addition of the linearity test will be an additional QA requirement for many existing systems that have SO_2 CEMS installed downstream of a wet or dry scrubber, will add significant cost to update software to integrate the new procedure, and potential costs to add the necessary hardware to existing systems to accommodate the new calibration gas cylinders, and will increase calibration gas costs, not only in the capital cost of purchasing the additional calibration gases but also in monthly demurrage fees.
- Section 63.10010(e)(6)(iii) – According to the commenter, this provision may require utilities to add a fourth calibration gas to the linearity sequence in order to have a calibration gas "nominally at a concentration level equivalent to the applicable emission limit." The commenter states that if a utility is required to include a fourth calibration gas level to the linearity check procedure, an additional cost in terms of hardware and software upgrades to integrate the fourth linearity calibration gas into the calibration system will be incurred by the utility. According to the commenter, this requirement is unnecessary and will not improve the quality of SO_2 data being collected. The commenter states that current guidelines in 40 CFR Part 75 ensure that the majority of emission measurements made by an SO_2 CEMS fall within a certain percentage of the monitor's calibrated span and that users are required to evaluate the span of the SO_2 CEMS

on annual basis, which has proved sufficient in maintaining the overall integrity and accuracy of the SO_2 emissions being reported. At a minimum, states the commenter, the EPA should quantify the term "nominally" (*e.g.*, a calibration gas within ±20 percent of the equivalent concentration level).

Response to Comment 5: The final rule will be amended to remove the 7-day calibration error test for units with spans less than or equal to 50 ppm and remove the fourth calibration gas nominally near the standard. The EPA disagrees that a linearity check is unnecessary to ensure quality assurance of the SO_2 CEMs for compliance at emission standard levels and will retain that requirement. In addition, sources may choose to comply with HCl CEMS or periodic HCl testing in lieu of updating their SO_2 CEMS system to check linearity quarterly.

3. Revisions to FGD applicability.

Comment 6: Commenters 17728 and 17775 support the EPA's inclusion of an option for use of an SO_2 CEMS to comply with a surrogate limit for SO_2; however, they believe several adjustments are needed to make this a reasonable option. The commenters state that to use the option, wet or dry FGD technology must be operated "at all times." The commenters state the EPA should clarify that this requirement is not intended to disqualify EGUs that experience SO_2 control device malfunctions or that must bypass controls during the initial portions of startups or to perform maintenance (which generally require bypass of the entire control unit). The commenter states that for units without a bypass stack, any resulting emissions would be monitored in the main stack with the SO_2 CEMS; for units with a bypass stacks, temporary bypass might be necessary during a malfunction or to perform necessary maintenance to minimize periods of malfunction. According to the commenter, either way, as long as the SO_2 emissions are accounted for those emissions will reflect the potential for higher HCl as well, and any unit complying with the 30-day rolling average SO_2 limit will achieve the necessary control for HCl (i.e., the acid gas HAP). Thus, the commenters believe the EPA should clarify that the "at all times" requirement does not apply to periods of malfunction, or to the temporary use of a bypass stack during periods of malfunction or maintenance, provided SO_2 emissions are accounted for and the applicable standard is met.

Commenter 17752 states the EPA must clarify in section 63.9991(a)(1)(iii) that "at all times" is intended to disqualify EGUs that operate SO_2 controls intermittently, and not to disqualify EGUs that experience SO_2 control device malfunctions or that must operate without control devices during periods of EGU startup and shutdown.

Commenter 17714 states that the EPA should clarify that operation of FGD technology is only required for periods when the affected unit is operating. Commenter 17714 states the requirement to operate the APCD "at all times" should include provisions to follow manufacturer's recommendations regarding when APCD operation is to be initiated and/or curtailed during startup/shutdown of the unit.

Commenter 17885 states that for the alternative SO_2 limit, the EPA should qualify that that "at all times" is not intended to disqualify units that experience control malfunctions or that bypass during startup/shutdown.

Comment 7: Commenters 18539 and 19120 note that section 63.9991(a)(1)(iii) indicates that the FGD must be operated at all times in order to qualify to use the alternate SO_2 limit to demonstrate compliance with the acid gas HAP emission limitation. The commenters believe that if a unit can demonstrate compliance with the applicable SO_2 limit based on monitored emissions from the bypass and the scrubbed stack, a source should be allowed to exhaust to the bypass stack, at least, on a limited basis, as many of these stacks are already equipped with SO_2 CEMS. One commenter notes that exhausting to the bypass stack is a necessary option in many cases, and provides four examples.

Comment 8: Several commenters (17800, 17868, 18428) believe the EPA should make clear that this requirement in section 63.9991(a)(1)(iii) is intended to disqualify EGUs that operate SO_2 controls intermittently, and not to disqualify EGUs that experience SO_2 control device malfunctions or that must turn off controls to perform maintenance. The commenters note the higher SO_2 recorded by the CEMS during such periods will reflect the potential for higher HCl as well, and as long as the SO_2 CEMS meets the surrogate standard for HCl these FGD off periods should not disqualify an EGU from using an SO_2 as a surrogate. The commenters suggest the EPA make clear that the existence of a bypass stack does not disqualify an EGU from complying with the standard.

Comment 9: Commenter 17886 supports the option to use SO_2 CEMS to comply with a surrogate SO_2 limit; however, the commenter believes use of a bypass stack during startups or malfunctions as part of good engineering and maintenance should not disqualify an EGU from this option. The commenter suggests the EPA could require sources to account for these periods as provided in 40 CFR section 75.16(c)(3), which requires use of a maximum potential value for each hour when the bypass stack is in use.

Comment 10: Commenter 18037 does not support the requirement that SO_2 controls must be operated at all times if the SO_2 surrogate is selected. The commenter believes that so long as a facility complies with SO_2 emissions limits, operators should have the flexibility to operate SO_2 controls in any mode to meet the compliance limit. The commenter recommends that the EPA remove the continuous control requirements regarding SO_2 from the proposed rule. The commenter believes this additional requirement is superfluous if SO_2 is a reasonable surrogate, and if facilities monitor SO_2 continuously using reliable CEMS. The commenter believes an EGU that demonstrates compliance with SO_2 limits, but whose SO_2 controls are not in continuous operation, should not be considered in violation of the rule.

Comment 11: Commenter 17909 suggests the EPA should allow a 12-month rolling SO_2 limit and clarify that FGD bypass is allowed during times of FGD forced outage. The commenter believes these changes would allow very limited continued operation through the bypass during upset conditions.

Comment 12: Commenter 18023 believes that for PC units, the EPA should allow a scrubbed unit to bypass for a short time and allow the source to use the SO_2 monitors in the bypass stack. As written, the rule appears to require a unit with the ability to bypass to install an HCl CEMS or otherwise monitor HCl on the bypass stack. If a unit that bypasses controls for a short period of time is capable of meeting the MACT SO_2 limit, then scrubber bypass should be allowed. The commenter believes there is no environmental justification for penalizing these units.

Response to Comments 6-12: In the final rule, the EPA has clarified the "at all times" language. The intent is that the FGD be operated during all boiler operations and not operated intermittently, seasonally, or on some other non-fulltime basis. Thus, this alternate limit is allowed even if bypass may occur during malfunction, but sources may be subject to penalties or other action if the malfunction causes the source to not comply with the requirements of the standards. We have established work practice standards for periods of startup and shutdown, as those terms are defined in the final rule, and the use of the FGD system must be in accordance with the work practice standards during those periods (i.e., the system must be engaged before coal or residual oil is burned in the boiler unit).

4. SO_2 as surrogate.

Comment 13: Commenter 17730 agrees with the proposal by the EPA to use SO_2 as a surrogate as one of the options for measuring the acid gases category of HAP. The commenter also appreciates the proposals reliance on the SO_2 CEMS as the basis of ongoing compliance with the requirements. The commenter believes SO_2 emissions were well correlated with the acid gases in the analysis of the EPA ICR test data. SO_2 CEMS are used by the commenter to measure the emissions of SO_2, and the commenter believes they produce accurate emission estimates.

Comment 14: Commenter 17758 believes there is no basis for testing of the surrogate SO_2 at a unit that is complying with the HCl standard or for HCl emissions testing at a unit with HCl CEMS. For example, states the commenter, proposed section 63.10006(h) requires EGUs "without SO_2 CEMS but with installed systems that use wet or dry flue gas desulfurization technology" to conduct "all applicable performance tests for SO_2 and HCl emissions" at least every year and to "conduct SO_2 emissions testing" at least every month. The commenter suggests the EPA make clear that these provisions do not apply to EGUs with HCl CEMS.

Comment 15: Commenter 17383 supports the use of SO_2 CEMS as a surrogate monitoring technology for HAP acid gases.

Comment 16: Several commenters (19536, 19537, 19538) endorses SO_2 CEMS methods to determine compliance, and believes they should be required, rather than presented as an option.

Comment 17: Commenter 17621 believes given the use of pulsed fluorescence analyzers, it is reasonable to expect that equipment will be available to measure SO_2 in the flue gas at the proposed alternative MACT limits for new and existing coal-fired EGUs (approximately 0.04 lb/MMBtu and 0.2 lb/MMBtu, respectively), even accounting for the dilution extractive sampling systems. The commenter notes that at the emission levels typically found in power plants, the impact of sample line losses has not been an issue and operators have minimal problems meeting the 7.5% relative accuracy; however, when trying to measure very low concentrations, sample line losses may make the RA criterion more difficult to meet.

Comment 18: Commenter 17725 believes there is no value in performing Cylinder Gas Audit (CGA) tests quarterly on SO_2 analyzers with span values less than 30 ppm SO_2 that are currently certified to report under 40 CFR part 75 rules. The commenter recommends the EPA add a subsection to section 63.10010(e) that clearly states that 40 CFR part 75 data substitution procedures and bias adjustment factors are not to be used to calculate the 30 boiler operating day average SO_2 emission rate.

Comment 19: Commenter 17886 recommends the EPA clarify that provisions in section 63.10006(k) do not apply to EGUs with SO_2 CEMS that are used to meet requirements pertaining to the alternative acid gas limit.

Comment 20: Commenters 17775 and 17868 recommend the EPA clarify the subsequent performance testing requirements for units without HCl CEMS in proposed section 63.10006(h) and (i). The commenters suggest the EPA make clear that the provisions for EGUs "without HCl CEMS" do not apply to EGUs with SO_2 CEMS, and must remove the initial testing requirement for HCl. The commenters believe there is no basis for testing of HCl at a unit that is complying with the surrogate SO_2 limit and proposed Tables 1 and 2 clearly provide sources the option of meeting an HCl or an SO_2 standard. Commenter 17775 also believes the EPA does not explain what it means by EGUs "without

SO_2 CEMS" or what significance those SO_2 CEMS have for EGUs not choosing to comply with the surrogate SO_2 limit. The commenter suggests that virtually all coal-fired EGUs covered by this proposed rule already have SO_2 CEMS installed as a result of other regulatory programs, like the Acid Rain Program.

Commenter 17775 notes proposed section 63.10006(j) requires EGUs "without HCl CEMS but with HCl emissions controls" to test for HCl at least every month, and proposed section 63.10006(k) requires EGUs "without HCl CEMS and without HCl emissions controls" to test for HCl at least every other month. The commenter notes there is nothing in the proposal to exempt EGUs with SO_2 CEMS, but not HCl CEMS, from proposed requirements applicable to EGUs "without HCl CEMS." The commenter also notes proposed section 63.10005(a) also specifically requires HCl testing initially for any EGU that uses "a continuous monitoring system that measures a surrogate for a pollutant (e.g., an SO_2 monitor)."

Comment 21: Commenter 17881 notes for those units with an SO_2 CEMS, the concept of an additional performance test every 5 years makes little sense, as such units are required to determine a new 30-day rolling average emission rate for every operating day following the initial 30-day compliance test.

Response to Comments 13 - 21: The EPA appreciates the support for the use of SO_2 as an alternate equivalent standard and reliance on an SO_2 CEMS. The EPA also agrees that sections 63.10005 and 63.10006 need to be clarified to be consistent with Table 5 – if an HCl CEMS is used, the SO_2 testing requirements do not apply, and vice versa.

5. Part 75 concerns.

Comment 22: Commenter 17722 supports inclusion of 40 CFR part 75 monitoring provisions for SO_2 CEMS; however, the commenter does not support the addition of new part 75 requirements. The commenter cites section 63.10010(e)(6), which requires additional provisions not currently needed for an SO_2 CEMS under part 75. The commenter notes that as a comprehensive monitoring rule, part 75 provides certified data within the means of the technology. The commenter notes these additional monitoring requirements were exempted from certain monitor ranges because the monitoring technology is unable to perform the EPA methods either due to monitor limitations or due to protocol limitations. The commenter believes since current part 75 SO_2 collected data is accepted by the EPA as credible evidence of compliance with Acid Rain provisions, it should also be acceptable to the EPA for demonstration of compliance with the MACT standard without creating additional requirements as listed in section 63.10010(e)(6).

Comment 23: Several commenters (17725, 18014, 18498) suggest that while the rule allows the use of Part 75 SO_2 CEMS, it includes additional QA/QC requirements that will be problematic. The commenters reference section 63.10010(e)(6)(i), which states the operator "must perform the 7-day calibration error test required in Appendix A to part 75 on the SO_2 CEMS whether or not it has a span of 50 ppm or less." The commenters do not understand what this requirement will accomplish as the majority of part 75 affected sources has completed initial certification years ago and has been collecting "quality-assured" data for years.

Comment 24: Commenters 17790 and 17820 have concerns with the linearity and 7-day calibration error test requirements contained in the proposal that are not required under part 75. Commenter 17820 believes requiring these tests will complicate compliance for EGUs currently complying with part 75 and without providing any added accuracy to the measurement. Commenter 17790 suggests these requirements be removed for companies that plan to use their part 75 SO_2 CEMS. The commenter notes

CEMS with a span less than 50 ppm are exempt from the 7-day calibration error and CEMS with a span less than 30 ppm are exempt from the quarterly linearity testing and that CEMS are meeting the 7-day calibration error specification on a daily basis during their daily calibration. The commenter also notes the EPA also determined that for CEMS with spans less than 30 ppm, the linearity testing was not significant at the lower emission level. The commenter notes that the EPA is requiring a calibration gas at a level equivalent to the emission limit, even if that means adding a fourth calibration gas level, and that adding this calibration gas level will cause significant cost and significant modifications to Data Acquisition and Handling Systems (DAHS). In addition, the commenter notes part 75 already has existing requirements to ensure the monitor span value is set at a level to cover the range of the unit's operating emissions.

Comment 25: Commenter 17873 believes the increased QA/QC requirements for SO_2 CEMS as a surrogate for HCl emissions goes well beyond what the EPA has previously required in either 40 CFR parts 60 or 75 monitoring requirements, and the EPA does not provide adequate justifications for increasing these QA/QC requirements beyond what part 75 requires. The commenter believes the fourth linearity calibration injection standard is overly burdensome to the industry.

Comment 26: Commenter 17775 believes no reason was provided for the requirements in the proposed section 63.10010(e)(6)(i) and (ii) that allows use of an SO_2 CEMS meeting part 75, but imposes linearity and 7-day calibration error test requirements not required under part 75. The commenter cites 67 FR 40394 and 40408-09 (June 12, 2002) in which the EPA specifically exempted CEMS with spans of 50 ppm or less from the 7-day calibration error requirement under part 75 because it was no longer necessary. The commenter also cites 63 FR 28032 and 28061/3 (May 21, 1998) where the EPA specifically exempted spans of 30 ppm or less from the linearity requirement in acknowledgment of the fact that the tests were no longer significant at low emission levels. The commenter suggests if these tests are no longer relevant or significant, there is no purpose in requiring them in this rule and that requiring the test will complicate compliance for EGUs currently complying with part 75 without providing any added accuracy to the measurement.

Comment 27: Commenters 17775 and 17820 believe the EPA provides no rationale for this added requirement in proposed section 63.10010(e)(6)(iii) that requires a calibration gas at a level equivalent to the emission limit, even if that would result in a fourth calibration level. The commenters note part 75 already includes provisions to ensure that the analyzer span value is set at a level that will result in use of calibration gases that are consistent with the emissions range over which the unit operates, citing 40 CFR part 75, Appendix A section 2.1.1. The commenters believe there is nothing to be gained by potentially adding a fourth calibration gas, and since existing SO_2 CEMS and the accompanying DAHS have not been certified using a fourth calibration gas, and are not currently designed to support a fourth calibration gas, this new requirement would unnecessarily increase costs for SO_2 CEMS. The commenters believe the EPA must remove these requirements, or issue for comment a proposal that provides some rationale for requiring these tests in this context.

Comment 28: Commenter 17821 strongly opposes the requirements in section 63.10010(e)(6)(iii) to introduce a fourth concentration level of calibration gases during the initial and subsequent quarterly linearity audits. The commenter states the EPA appears to be imply that more accurate measurements would be obtained by the SO_2 monitoring system if the fourth level of calibration gases was added; however, the commenter believes no additional accuracy would be obtained by the introduction of an additional gas injection level, and it would simply consume additional resources and slow down a test that already takes 2-3 hours to complete. The commenter also believes it would also necessitate the invalidation of hourly data during the injection of the linearity gases. The commenter notes that by adding the fourth gas injection level, sources would be forced to inject gases for approximately 40 minutes (10 minutes for each of the four gas concentrations); when the 5-7 minutes required to reach a stable stack gas reading are added to that total, sources would not collect enough valid stack measurement minutes within an hour to validate the hour. The commenter therefore believes this process would result in approximately 2-3 hours of invalid data each and every quarter.

Commenter 17821 additionally states the alternative limit when using an SO_2 emissions system for compliance with an HCl limit under these proposed rules is defined in terms of lb/MMBtu. SO_2 and diluent monitors (O_2 or CO_2) are audited for linearity in ppm concentration or percent concentration, not as a value expressed in lb/MMBtu. The commenter believes to require a source to evaluate an SO_2 or diluent monitor for linearity at a fourth concentration level "nominally at the concentration level equivalent to the applicable emission limit" would be extremely subjective. The commenter states that concentrations of SO_2 and diluent gases can change as the unit load changes due to the amount of excess air being supplied to boilers at various loads. This variability in the air excess flow would result in a change to the nominal equivalent values for the test.

Commenter 17821 continues to state that sources currently using SO_2 monitoring systems in compliance with 40 CFR 75 are required to develop span ranges that capture the majority of the hourly averages between 20% and 80% of the span range. According to the commenter, with this requirement in place, most sources are utilizing span ranges that are set to capture the majority of nominal readings at approximately 50% of that span range. 40 CFR 60 and 40 CFR 75 cylinder gas audits and linearity audits already require a source to inject a gas in the range of 50% to 60% of the span range of the monitor; therefore, an injection of audit gas in the "nominal" range of measurement is typically performed. Additionally, states the commenter, all sources equipped with SO_2 emission control systems utilize dual range SO_2 monitoring systems (as required by both 40 CFR 60 and 40 CFR 75). The commenter believes performing a linearity audit with a fourth injection level on the high range of the SO_2 monitor at the "nominally at the concentration level equivalent to the applicable emission limit" would be meaningless as the high range of the monitor is not intended to measure low level concentrations but is designed to measure higher concentrations in the event of a malfunction or upset of the SO_2 emission control system. The commenter believes very low concentrations of SO_2 will dictate very low range measurement on these dual range analyzers, which will make passing a linearity test very difficult. The commenter states that the standard is percent of the reference value, which may put the error limits inside the accuracy standards for the reference gas. The commenter states that part 75 provides a waiver for linearity testing of ranges less than 50 ppm and an alternate standard for ranges less than 200 ppm. The commenter recommends that these be allowed for the SO_2 surrogate measurement as well, which will also serve to avoid maintaining separate databases for CSAPR and MACT purposes.

Comment 29: Commenter 17881 believes the restrictions and caveats placed on the use of part 75 SO_2 CEMS at section 63.10010(e)(6), the provisions of paragraphs (i) and (ii) would require that 7-day calibration error tests and linearity tests be conducted on low-level emissions monitoring systems (i.e., systems with span values of less than 50 ppm or 30 ppm, as applicable) make little sense, as the EPA has already evaluated the utility of conducting such tests under 40 CFR part 75 and concluded that these tests were not appropriate for level-level emissions monitoring systems.

Commenter 17881 believes the provisions of section 63.10010(e)(iii) which would also require that at least one calibration gas level used for the linearity tests have the same nominal concentration level equivalent to the applicable emission limit (and that a fourth such gas be used if none of the required low, mid or high gases meet this requirement) are nonsensical, as the vast majority of part 75 SO_2

CEMS installed on units with add-on SO_2 control devices will be dual-range instruments. As such, states the commenter, the high level range of these instruments will generally be reflective of SO_2 emissions without add-on SO_2 controls, which will surely be much higher than the applicable SO_2 emission limit, and thus, the SO_2 CEMS will be calibrated over an aggregate (i.e., low and high) measurement range which encompasses the applicable SO_2 emission limit, and this should be adequate to ensure the accuracy of the SO_2 CEMS measurements at or near the applicable emission limit. The commenter suggests a more reasonable caveat (in lieu of section 63.10010(e)(6)(iii)) would be a prohibition on the use of a default high range value as allowed under 40 CFR part 75, Appendix A, section 2.1.1.4(f) for those dual span units with SO_2 emissions controls. According to the commenter, this would essentially ensure that any EGU which elects to comply with a surrogate SO_2 limit (which inherently requires add-on SO_2 controls) has quality assured SO_2 measurement ranges which encompass the applicable SO_2 emission limit.

Commenter 17881 believes the concept of a calibration gas with a concentration nominally equivalent to the applicable SO_2 emission limit is unworkable, as the SO_2 emission limits are not inherently expressed on a concentration basis (i.e., are expressed as lb/MMBtu or lb/MWh), are assessed on a 30-day rolling average basis, and would be influenced by boiler operating loads and the resulting diluent gas levels and electrical outputs. The commenter provides an example for a subbituminous boiler and questions that given the concentration equivalent of a given SO_2 emission limit is influenced by boiler operating conditions, how could a nominally equivalent concentration even be determined with any level of certainty. The commenter also questions what is nominally equivalent in the context of the example provided.

Comment 30: Commenter 17902 believes section 63.10010(e)(6)(i) thru (iii) will require additional calibration error and linearity check tests that are not currently required under 40 CFR part 75 and are not necessary and may not even be feasible due to instability of calibration gases at lower concentration levels. The commenter recommends that the final rule should not require additional SO_2 CEMS requirements beyond the QA/QC requirements and guidance in the existing federal regulations for 40 CFR part 75.

Comment 31: Commenter 17868 suggests the EPA allow all part 75 exceptions. The commenter notes proposed section 63.10010(e) allows use of an SO_2 meeting part 75, but disallows the linearity and 7-day calibration error test exceptions and requires a calibration gas at a level equivalent to the emission limit (even if it is a fourth level).

Comment 32: Several commenters (17775, 17800, 17811, 17868, 18014) note that proposed section 63.10021(a)(13) sets out the ongoing requirement for SO_2 CEMS, which are similar to proposed section 63.10010(e), except this provision does not reference the part 75 option. One commenter suggests the EPA reference the part 75 alternative in this provision as well, or consolidate the two provisions.

Comment 33: Commenters 17725 and 18498 note that section 63.10010(e)(6)(ii) states that one “must perform the linearity check test required in appendix A to part 75 on the SO_2 CEMS whether or not it has a span of 30 ppm or less”; however, this requirement ignores the EPA’s previous acknowledgement that a linearity check “begins to lose its significance” at span values less than or equal to 30 ppm as discussed in the proposed 1998 revisions to 40 CFR part 75. One commenter provides an example and proposes the requirement should be removed and replaced with the part 75 exemption.

Comment 34: Several commenters (17725, 18014, 18498) reference section 63.10010(e)(6)(iii), which states “the initial and quarterly linearity checks required under Appendix B of Part 75 must include a calibration gas (at a fourth level, if necessary) nominally at a concentration level equivalent to the applicable emission limit." The commenters see no reason to introduce a fourth calibration gas and the term "nominally" is not clearly defined. The commenters state that part 75 has requirements in place to ensure that the analyzer span is set to obtain accurate and representative data. Commenter 17725 notes this requirement will significantly increase SO_2 CEMS operating cost as the system will need to be modified to include an additional regulator, the DAHS will need to be reprogrammed, and costs will be incurred to purchase a fourth calibration gas (including monthly cylinder demurrage).

Comment 35: Commenter 17752 requests the EPA clarify what "if necessary" means in section 63.10010(e)(6)(iii) in regards to conducting linearity checks at a fourth level. The commenter believes if an EGU qualifies for and elects to use a SO_2 CEMS, yet has a state limit that is more restrictive, there would be no benefit to having a fourth level at the proposed applicable emission limit. According to the commenter, any emission limit will reside in the lower range of a dual range analyzer, which is typically a narrow range to begin with. The commenter believes this requirement is "not necessary" and would only add complications and costs to an already accurate and sound system.

Comment 36: Commenter 17821 supports the EPA's inclusion of the option to operate, maintain, and quality assure an SO_2 monitoring system under 40 CFR 75 if the source operates such a system for compliance with Acid Rain.

Comment 37: Commenter 17886 suggests the EPA harmonize the SO_2 CEMS requirements with part 75 as most if not all EGUs should already have these systems in place meeting part 75 requirements. The commenter believes failure to harmonize monitor requirements in past regulations has created confusion and additional costs for both the EGU and the EPA.

Comment 38: Commenter 18014 states that in Table 5 for the SO_2 CEMS (Item 5) in the "using" column for Item a, the table should include the alternative to use Part 75 requirements for "installation", "operate", and "maintain CEMS." (*See* section 63.10010(e).) The commenter also notes the table references section 4.1.3 and 5.3 of Appendix A to the subpart, but SO_2 is never mentioned in Appendix A.

Comment 39: Commenter 17881 objects to subjecting part 75 monitoring systems to the data reduction procedures in section 63.10010(e)(4), as these procedures are in part inconsistent with the part 75 data reductions procedures at section 75.10(d). The commenter cites the requirements from section 63.8(g)(2) and section 75.10(d)(2), noting that while the language appears similar, it could still result in different data validation cases where maintenance or quality activities are conducted in a given hour and only two data quadrants are used to validate the hour. For example, states the commenter, if an unit operated for 60 minutes in a given clock hour and collected valid 1-minute values at minutes 14 and 15 due to quality assurance activities, such an hour would be valid under the provisions of section 63.10010(e)(4) but invalid under the 40 CFR 75.10(d)(1) provisions. The commenter believes forcing part 75 subject sources to maintain two separate sets of data based upon two different validation regimes is overly burdensome and unwarranted, and suggests part 75 SO_2 CEMS should not be subject to the provisions of section 63.10010(e)(4).

Comment 40: Commenter 18014 suggests the EPA should add a subsection to section 60.10010(e), which clarifies that bias adjusted data and part 75 missing data shall not be used in calculating the 30 boiler operating day average SO_2 emission rate. According to the commenter, although this is discussed in Appendix A to subpart UUUUU for Hg CEMS (Reference Appendix A sections 1.4 and 4.1.2.4), this data exclusion is not clearly stated for SO_2 CEMS.

Response to Comments 22 - 40: After reviewing the comments and assessing the need for a “nominal” gas for the linearity test, the EPA has removed this requirement from the final rule while retaining a requirement for a linearity check even for low SO_2 concentrations. Sources can already report linearity tests for these units within the context of the existing ECMPS reporting without triggering any critical errors regardless of the test results. This test can be accommodated within the current framework without causing issues for part 75 reporting. The 7-day calibration error test is removed as unnecessary. As noted elsewhere in this response to comments document, the final rule confirms that the bias adjustment and substitute data provisions under part 75 do not apply when using an SO_2 CEMS to demonstrate compliance with the SO_2 emission limit in this rule.

5A09 - Testing/Monitoring: Application of HCl CEMS

Commenters: 16513, 17383, 17402, 17621, 17622, 17627, 17638, 17681, 17696, 17704, 17705, 17715, 17716, 17718, 17724, 17725, 17728, 17729, 17756, 17769, 17775, 17790, 17795, 17800, 17813, 17820, 17821, 17851, 17868, 17881, 17886, 18014, 18037, 18443, 18539, 19114, 18023

1. HCl CEMS is not proven technology.

Comment 1: Numerous commenters (17383, 17402, 17681, 17696, 17704, 17705, 17715, 17718, 17724, 17728, 17729, 17627, 17638, 17769, 17775, 17790, 17795, 17813, 17820, 17868, 18037, 18443, 18539, 19114, 18023) note concerns with HCl CEMS technology.

Comment 2: Commenter 17402 recommends that the EPA remove the HCl CEMS monitoring requirement from the proposed rule until HCl CEMS are proven technologies. The commenter states that EGU sources have limited experience with HCl CEMS, and limited information on the accuracy and long-term performance of such technologies as applied in the field. The EPA proposes an HCl standard equivalent to approximately 2 ppm, which the commenter believes is an extremely low performance standard for a new monitor to meet.

Comment 3: Commenters 17638 and 17681 state that there are no FTIR HCl CEMS currently in use in the U.S. on a coal-fired EGU.

Comment 4: Commenter 17813 does not believe HCl CEMS are in production and questions if there are any HCl CEMS that work.

Comment 5: Commenter 17696 states that while the EPA suggests that FTIR CEMS may be appropriate to monitor HCl emissions pending promulgation of a performance standard specific to HCl CEMS, 76 FR 25031, FTIR does not have a track record of consistently and reliably measuring HCl levels expected in the stack gas of EGUs.

Comment 6: Commenter 17704 believes the technology for HCl CEMS is not fully developed or proven for EGUs. The commenter understands that stack testing for HCl every month is offered as an alternative, but scheduling testing that often is difficult and not practical; therefore, that really only leaves the choice of HCl CEMS. The commenter believes that HCl CEMS have been used to measure higher concentrations for other industries; however they are not proven at the low levels proposed in the rule.

Comment 7: Commenter 17705 believes the use of HCl CEMS has been attempted primarily on dry stacks, and that HCl CEMS may not be available for use on wet stacks, noting concern that many EGUs plan to use wet FGD technology to comply with the proposed acid gas standards. In addition, states the commenter, information provided by EPRI indicates that the proposed HCl standard may be lower than the quantitation limit of the two types of instruments currently available for HCl measurement. If the EPA retains a numeric HCl standard in the final rule, the commenter encourages the EPA to take a leadership role in assuring that the monitoring methodology that is required is actually available for use across a broad range of plant configurations and can reliably demonstrate compliance with the standard.

Comment 8: Several commenters (17718, 17627, 17715, 18037, 18539) state HCl CEMS currently are not commercially available or adequate for in-stack measurements and likely will not be available by the compliance date of the rule. The commenters believe sources will be forced to either take a fuel limit or an operating parameter limit. The commenters state the fuel analysis limit is impractical as it relates to a coal-fired facility because of the variability that is inherent in coal, and that it will be impossible to control fuel deliveries in such a manner as to negate the possibility of burning coal with chlorine content above that which was used during compliance testing.

Comment 9: Commenters 17715 and 19114 state HCl is not routinely monitored by EGUs, and there is little stack test data beyond that collected by the EPA during the ICR process. The commenter states that no HCl continuous monitors were used to collect any of the data used by the EPA to establish the HCl standard, and there is no information about HCl emissions at conditions other than normal full load operations, but nevertheless, the EPA proposes to rely on continuous HCl monitors as its preferred monitoring method for compliance. The commenter believes it is imprudent for the EPA to set forth a monitoring standard for which there has been very limited experience in the relevant industry and for which the technology has not been commercially developed. The commenter notes that the EPA states that FTIR has been shown to be adequate for in-stack measurements. However, the commenter states FTIR has been shown to be unreliable in stack applications, especially at emission rates as low as the EPA has proposed. The commenter recommends the EPA should not dictate FTIR as the technology to be utilized.

Comment 10: Several commenters (17383, 17724, 17820) are concerned that HCl monitors are not a proven option in the electric utility industry. According to the commenters, while these monitors exist and have operated on other sources, the electric utility sector presents distinct challenges. Commenter 17724 questions the need for SO_2 monitoring in addition to parametric monitoring associated with scrubber operation.

Comment 11: Commenter 17728 believes HCl CEMS are not at this point a viable option, as the technology remains unproven. The commenter expresses concerns about the ability of HCl CEMS to accurately measure compliance with the proposed standard.

Comment 12: Several commenters (17728, 17775, 17820) believe the EPA must consider the limitations of compliance measurements when setting enforceable standards.

Comment 13: Commenters 17718 and 17729 state at the EPA emission rate of 0.002 lb/mmbtu, the HCl in the flue gas will be less than 2 ppm. The commenters believe that currently, HCl CEMS are not capable of measuring accurately at concentrations below 2 ppm.

Comment 14: Several commenters (17775, 17868, 17820) are concerned about the ability of HCl CEMS to accurately measure compliance with the proposed standard because the limit is at or near the detection limit for current HCl CEMS technology.

Comment 15: Commenter 17790 states that while there are limited HCl CEMS installations, they are not a proven technology like SO_2 or NO_X CEMS. The commenter also suggests there are significant technology obstacles in applying HCl CEMS to a wide variety of sources with different temperatures, moisture and gas conditions. The commenter notes its own experience with significant problems with Hg CEMS, the heated umbilical (a critical part of the CEMS) is unproven at extended lengths (over 200 feet).

Comment 16: Commenter 17769 believes there are valid technical concerns regarding the feasibility and commercial acceptance of the use of HCl CEMS, particularly that the reactivity of HCl, makes obtaining reliable measurements a difficult task. The commenter identifies the three basic HCl CEMS configurations and discusses technical issues with each. The commenter describes sample conditioning problems associated with extractive systems, difficulties with representative measurements and operation and maintenance (O&M) problems for in-situ instruments, and NH_3 interactions with HCl creating problems for dilution sampling systems. The commenter also discusses the MCS 100 E Multi Component Analyzers as the most widely employed and presumably most advanced HCl CEMS and notes issues with detection limits associated with the use of the unit. The commenter believes there are substantial technical questions regarding the use of HCl CEMS, and the EPA should not require them as part of the EGU NESHAP.

Comment 17: Commenter 17795 believes that HCl CEMS are not an option at the proposed levels with a certification performance specification that has a known negative bias. For existing units, states the commenter, an HCl standard of 0.002 lb/MMBtu equates to 1.2 ppm (assuming a heat rate of 10,000 Btu/kW). The commenter believes while this value is above the detection limit it will be extremely challenging to demonstrate compliance through a continuous HCl emissions monitor. For example, states the commenter, the lowest achievable emission rate (LAER) for new combined cycle combustion turbines is approximately 2.0 ppm of NO_X. Unlike HCl, NO_X is not water soluble or temperature dependant prior to analysis. The commenter notes their industry has more than 30 years of experience monitoring NO_X and limits of 2.0 ppm are challenging to demonstrate on a continuous basis. According to the commenter, measuring a highly water soluble compound that is expected to be less than 1.2 ppm where water is a large part of the sample matrix will be problematic and may simply result in unreliable data.

Comment 18: Commenter 18443 believes the cost and accuracy of HCl CEMS do not justify the difference in emission reduction measurements produced by a performance test and continuous compliance metrics. The commenter suggests HCl CEMS were developed for sources with much greater HCl emissions than EGUs and as such do not provide precision and accuracy at the range they are expected to operate. Additionally, states the commenter, the HCl standard does not take into account chlorine variability in coal. The commenter recommends instead of effectively mandating HCl CEMS, EPA should allow sources to comply with HCl limits through an annual performance test, in conjunction with documented process metrics.

Comment 19: Commenter 19114 notes that HCl is not routinely monitored by electric generating units, and there is little stack test data beyond that collected by the EPA during the ICR process. No HCl continuous monitors were used to collect any of the data used by the EPA to establish the HCl standard, and there is no information about HCl emissions at conditions other than the limited data available for normal full load operations. The commenter believes it is imprudent for the EPA to set forth a monitoring standard for which there has been very limited experience in the relevant industry and for which the technology has not been commercially developed. The EPA states that FTIR has been shown to be adequate for in-stack measurements. However, FTIR has been shown to be unreliable in stack applications, especially at emission rates as low as the EPA has proposed. Given these (and other) uncertainties regarding FTIR performance, the commenter believes the EPA should not dictate FTIR as the technology to be utilized. The commenter provides several examples of concerns expressed by agencies regarding the use of HCl CEMS, including excerpts from state agencies in their Response to Comments document that supported the issuance of final air permits.

Comment 20: Commenter 18023 believes there is only one HCl CEMS in operation in the U.S. on a coal-fired power plant stack and it is a tunable diode laser (TDL) based device. The commenter states TDL is not the EPA's preferred FTIR technology, so there is no performance specification available for it. The commenter states that this existing TDL device also uses the open path measurement approach and, as such, does not lend itself to daily QA/QC procedures typical of the power plant CEMS equipment that meets Part 75 requirements. According to the commenter, the current technology (FTIR) used for stack testing is not very rugged; sample transport issues may require HCl CEMS analyzers to be stack mounted, which will provide a maintenance and availability challenge. According to the commenter, most analyzers require stable temperature and humidity that would be difficult to manage on a stack exposed to ambient or above ambient temperatures.

Comment 21: Commenter 18023 suggests HCl CEMS must work at extremely low concentrations to meet the proposed MACT standard. The commenter states that NIST does not have any HCl standards, and the lowest concentration of EPA Protocol HCl gas advertised by a gas vendor is 25 ppm. The commenter states that that value is based on gravimetric (weight) traceability, and converted to ppm, the limit in the proposed rule is approximately 1 ppm. According to the commenter, this limit may be below the quantitation limit (QL) of the available instruments and thus would not be measureable.

Response to Comments 1-21: The EPA disagrees with commenters' contention that continuous HCl monitoring is premature or not available for the measurement at the limits set in the proposed standard. We understand from vendors of HCl CEMS that they have been used on source categories such as municipal waste combustors, cement plants, and biomass and other power generation units. We have reviewed HCl CEMS vendor technology claims and found sufficient capability to support this rule requirement. We are presently engaged with representative stakeholders to develop a generic performance specification for HCl CEMS. The HCl Performance Specification is scheduled for completion in time to be responsive to this rule promulgation. To use the HCl CEMS option at the start of the program, the EPA has included a comparable performance specification PS 15, using a Fourier Transform Infrared (FTIR) analyzer, which could be employed in the event that the issuance of PS for HCl CEMS is delayed. Should an EGU owner or operator be concerned about using HCl CEMS as a compliance demonstration method, other options exist for acid gas HAP monitoring including: 1) using HCl CEMS for compliance, 2) seeking approval for an alternative HCl monitoring procedure through section 63.7 f., 3) monitoring SO_2 continuously as a surrogate for HCl at facilities equipped with wet scrubber control technology for $SO_{2,}$ and 4) frequent reference method testing. Including these options in the rule provides flexibility to adopt CEMS monitoring options as the technology continues to mature and EPA performance specifications become available.

Comment 22: Commenter 17622 states they recognize the reluctance of the utility industry to proceed with plans to measure HCl because 1) They know it can be difficult to measure in low concentrations; 2) The technologies used for it such as FTIR, TDL or Perma Pure driers with GFC analyzers are unfamiliar to them; 3) The EPA has not published performance specifications for HCl measurement leading to some uncertainty. The commenter believes that if electric generating facilities can identify a reliable, low-maintenance, affordable option for low level HCl measurement (0-10 ppm), they will adopt it more readily. The EPA should help try to prove this point out over the coming months.

Response to Comment 22: The EPA acknowledges that certain applications of HCl CEMS will require further demonstrations and advances for this technology and is currently working on HCl PS for technologies other than FTIR.

2. Concerns over lack of performance specification.

Comment 23: Multiple commenters (17402, 17638, 17681, 17696, 17716, 17728, 17729, 17769, 17800, 17820, 17821, 17851, 17868, 17881, 17868, 17881, 17886, 18014, 18023) express concern that the agency has not made available performance specifications for HCl CEMS.

Comment 24: Commenter 17402 states the absence of such requirements makes it difficult for regulated units to comment on how they might comply with the proposed QA/QC specifications in the context of the Utility MACT rule.

Comment 25: Commenter 17696 believes it is premature and inappropriate for the EGU NESHAP rule to specify the use of HCl CEMS given that the EPA has not yet promulgated a performance standard specific to HCl CEMS. Without the existence of an accepted performance specification for HCl CEMS in advance of the compliance dates, the commenter believes EGUs cannot reasonably be expected to purchase and install HCl CEMS and rely on them for compliance determinations.

Comment 26: Several commenters (17716, 17820, 18014) state the EPA has developed no performance specification for non-FTIR based HCl CEMS. Table 5 lists PS 6, but the commenters believe PS 6 does not apply since it is for systems that measure pollutant emissions in units of mass per unit of time. The commenters state the lack of a performance specification for HCl CEMS (coupled with limited utility HCl CEMS operating experience, particularly for compliance near the detection limits of the systems) makes it difficult to provide meaningful comments.

Comment 27: Commenter 17729 recommends the EPA should not require compliance monitors for which an EPA performance specification does not exist.

Comment 28: Several commenters (17775, 17795, 17800, 17868) note that the EPA proposes to require certification of HCl CEMS according to PS 15 or PS 6. The commenters state that as the EPA acknowledges in the preamble, PS 15 applies only to FTIR CEMS. PS 6 applies to continuous emission rate monitoring systems ("CERM"), which measure mass emissions rate per unit of time, not conventional CEMS. The commenters note FTIR CEMS is not a viable option and sources need a well documented HCl performance specification well in advance of the compliance date in order to evaluate and procure appropriate instrumentation. The commenters state that in order to provide an HCl CEMS option, the EPA says "we expect to publish (a performance specification) prior to the compliance date of this proposed rule and to make it available to source owners and operators" (76 FR 25031). The commenters believe in the absence of an existing specification, the EPA should recognize in the rule that PS 15 does not apply to HCl CEMS.

Comment 29: Several commenters (17775, 17795, 17800, 17820, 17868) support the EPA's decision to convene a workgroup of interested stakeholders to aid in development of an appropriate performance specification. The commenters suggest the EPA allow EGUs to petition the EPA for use of an alternative specification if none has been promulgated by the time EGUs need to make decisions about their compliance options.

Comment 30: Commenter 17868 notes they supports the option for use of HCl CEMS and urges the EPA to complete work on a reasonable performance specification.

Comment 31: Commenter 17886 recommends that the EPA make HCl CEMS monitoring requirements contingent upon issuance of an HCl CEMS performance specification, as an HCl CEMS Performance specification is not currently available and the EPA has set the proposed HCl limits near the detection level of current technology. The commenter also believes, since the proposed limits are lower than the quantification limits of current technology, HCl CEMS should only be used for purposes of CAM.

Comment 32: Commenter 17881 has generally heard that the FTIR technology associated with PS 16 is not a viable option at this point in time due to concerns about detection limits in EGU exhaust gas matrices, potential measurement issues in wet stack environments, lack of low-level calibration standards, etc. The commenter suggests that until such time as the EPA has promulgated performance specifications for HCl and HF, the EPA should allow affected EGUs to petition for the use of an alternate performance specification. The commenter notes it is possible that new EGUs may face a compliance date as early as 1/1/2012, and believes it is highly unlikely that an HCl PS can be developed by that time. The commenter also notes it is not possible to comment on the QA requirements for HCl CEMS when there is no performance specification available.

Comment 33: Commenter 17769 notes that there are no performance specifications or quality-assurance provisions for HCl CEMS and the commenter is not aware of any FTIR HCl CEMS currently in use in the U.S. on a coal-fired EGU. The commenter notes that currently no federal regulations require the use of HCl CEMS without express exemptions, alternatives and caveats. The commenter provides examples including the Portland Cement NESHAP, CISWI NSPS and the proposed NESHAP for Polyvinyl Chloride and Copolymer Production. The commenter cites several rulemakings in which the EPA expressed various reasons for its hesitation to require the use of HCl CEMS, including lack of data, significant costs, and lack of performance specifications. The commenter believes the EPA's rationale for not adopting performance specifications (specifically, PS-13) is that the EPA could not demonstrate that an HCl CEMS would meet the specifications, citing 64 FR 52828, 52930. The commenter believes there is no certainty over the suitability and reliability of HCl CEMS and that the EPA must provide public notice and an opportunity for comment on any specifications prior to EPA requiring them as part of any rule.

Comment 34: Commenter 17821 encourages the EPA to allow the use of alternate HCl CEMS performance specifications so the choice of HCl CEMS is not limited to FTIR monitoring systems. The commenter believes that because the FTIR is not a practical monitoring option, using an HCl CEMS is not a realistic option for companies to consider without another option. According to the commenter, therefore many sources would have to revert to either using SO_2 as a surrogate, or to conducting stack testing at an unreasonable frequency. The commenter believes FTIR CEMS are difficult to calibrate and maintain. They typically require a level of expertise to set up, operate, and maintain that is far above the typical CEMS technician found at a power generation facility. The commenter notes that some states, including Indiana and Pennsylvania, have approved the use of alternate performance specifications for HCl CEMS on hazardous waste incinerators allowing the use of HCl CEMS other than those based on FTIR methods.

Comment 35: Commenter 17851 believes the EPA should not apply PS 15 to HCl CEMS, but should promulgate a PS specifically designed for these instruments. The commenter notes most commercial HCl CEMS use some form of infrared light attenuation to measure HCl concentrations and that requiring HCI CEMS to use PS 15 is simply not appropriate. The commenter believes the EPA should promulgate a performance specification specifically for HCl CEMS much like they have performance specifications for other CEMS (e.g., PS 11 for PM CEMS, and PS 12A for Hg CEMS, etc.). The commenter also believes that it is not appropriate to require compliance with an HCl CEMS unless there is a promulgated performance specification for HCl CEMS. The commenter suggests that these CEMS should not be required until a performance specification for these types of units is promulgated. However, if the agency decides to require these CEMS, the commenter believes there is a better interim solution than PS 15. The EPA has already approved two preliminary other test methods for HCl CEMS, OTM 22 and 23. The commenter believes that it makes more sense to temporarily use a preliminary test method already approved for HCl CEMs than to use an already promulgated performance specification that may not apply. The commenter suggests that the EPA modify the final rule to allow the use of OTM 22 and 23 instead of PS 15.

Comment 36: Commenter 18023 believes it is inappropriate to require HCl CEMS without appropriate industry practice demonstrating their availability and without a relevant Performance Specification.

Commenter 17775 states that the EPA must provide a reasonable performance specification for HCl and HF CEMS in time for EGUs to make decisions regarding compliance options.

Response to Comments 23 - 36: See Response to Comments 1-21 under 5A09 of this document.

3. Proposed alternatives.

Comment 37: Commenter 17704 believes as an alternative, a stack test emission factor based on an annual stack test would be more appropriate for their Powder River Basin (PRB) subbituminous coal units. According to the commenter, the amount of chlorine in the PRB coal the commenter utilizes does not vary much over a year, and a once per year stack test emission factor would be a sufficient means of calculating HCl emissions. The commenter suggests adding an option that would have an alternative for using a stack test emission factor instead of HCl CEMS, as long as, the fuel utilized by the unit does not change during the year. The commenter states that if a new fuel is introduced a new stack test could be required.

Response to Comment 37: The rule provides an alternative to an HCl CEMS based on periodic stack testing. See section 63.1006(j) and (k). The required testing frequency is more frequent than the suggestion made by the commenter.

Comment 38: Commenter 17728 recommends that if no performance specification is forthcoming by the time decisions about compliance options need to be made, the EPA should allow EGUs to petition for use of an alternative specification.

Response to Comment 38: Sources may petition for an alternative specification consistent with the provisions of section 63.7.

Comment 39: Commenter 17724 questions the need for SO_2 monitoring in addition to parametric monitoring associated with scrubber operation. The commenter suggests that like PM, the EPA should allow a source to choose either SO_2 monitoring or scrubber parametric monitoring in conjunction with fuel analysis as a continuous compliance option, and that the EPA should not categorically create secondary compliance monitoring.

Response to Comment 39: If an SO_2 CEMS is used consistent with the alternative SO_2 limit included in the rule, no parameter monitoring requirement applies.

Comment 40: Commenter 17715 supports SO_2 as a surrogate for HCl at scrubbed units.

Response to Comment 40: The EPA acknowledges the commenter’s support.

Comment 41: Commenter 17402 suggests in the alternative that facilities be permitted to utilize monthly fuel sampling coupled with periodic stack testing to meet monitoring compliance obligations.

Response to Comment 41: The final rule eliminates the fuel sampling option. A source may use an SO_2 CEMS where an FGD is installed, may use HCl CEMS, or may conduct periodic testing to demonstrate compliance.

Comment 42: Commenter 17696 believes until the EPA develops an accepted performance specification for HCl CEMS, that HCl CEMS should be used for compliance purposes with the EGU NESHAP rule only upon the EPA approval of an alternative monitoring method in accordance with 40 CFR 63.8(f).

Response to Comment 42: The EPA has set forth PS 15, which uses a Fourier Transform Infrared (FTIR) analyzer as an acceptable alternative for HCl CEMS performance specifications. Sources may seek alternative specifications through section 63.7. See also Response to Comments 1-21 under 5A09.

Comment 43: Commenter 17775 suggests that in the absence of an existing specification, the EPA should recognize in the rule that PS 15 does not apply to HCl CEMS and allow EGUs to petition the EPA for use of an alternative specification if none has been promulgated by the time EGUs need to make decisions about their compliance options.

Response to Comment 43: See response to Comment 42, directly above.

Comment 44: Commenter 17621 believes there are three likely candidate technologies for continuous measurement of gas-phase HCl: FTIR, tunable diode laser (TDL), and gas filter correlation (GFC); however, there is little or no experience with any of these technologies on EGUs, although all three have been used in Europe on municipal waste incinerators. The commenter states that the EPA has approved a reference method using FTIR for HCl in cement plant emissions. The commenter states that GFC is widely used on waste incinerators in Europe for HCl monitoring, but U.S. experience with this technology on EGUs is limited to CO_2 monitoring. According to the commenter, all of these technologies operate in the near infrared range and are to some extent subject to interference from water vapor, but both FTIR and TDL systems are able to resolve this interference.

The commenter notes with increasing measurement path there is a tradeoff between increased sensitivity and loss of signal strength. According to the commenter, particulate and entrained droplets in the flue gas can degrade the signal strengths in an in situ application in wet stacks, and demonstration of in situ techniques in a wet stack environment needs to be conducted. An alternative approach is to extract a gas sample and measure HCl. The commenter states that sample transport in a hot, wet flue gas is problematic and would require multipass measurement cells to achieve sufficient path length for the required sensitivity. Currently, states the commenter, the only installation on a U.S. EGU is an in situ TDL on a dry stack, and in that application, there was sufficient intensity to measure HCl and to identify process variations. The commenter states that there is no experience with HCl monitors on a wet stack; the preferred installation by the suppliers is to make an in situ measurement, or at least place the instrument close coupled to the stack, to avoid problems with condensation of HCl during transport.

The commenter notes that the key tasks that need to be completed before an HCl monitor can be deployed and used for compliance measurements include: (1) Determine detection and quantitation limits; (2) Quantify interferences of likely species in flue gas; (3) Validate CEMS in a wet stack; (4) Develop alternative extractive sampling techniques; (5) Develop low-level calibration standards; and (6) Develop and validate an EPA performance specification.

Comment 45: Commenter 17725 suggests HCl CEMS should not be limited to FTIR monitoring methodology as HCl CEMS based on FTIR technology tend to be very expensive to maintain and are labor intensive. The commenter suggests newer technologies such as Tunable Diode Laser Spectroscopy (TDLS) and Ion Mobility Spectroscopy (IMS) are showing great promise as a suitable replacement for selective gas components such as HCl and HF.

Response to Comments 44 - 45: The EPA acknowledges that certain applications of HCl CEMS will require further demonstrations and advances for this technology. The agency is working to finalize a PS for HCl CEMS (not limited to just an FTIR approach) and notes that the use of an HCl CEMS is just one option for demonstrating compliance under the final rule, not a requirement. The PS for HCl CEMS will include consideration of detection and quantitation limits, interferences, performance of CEMS under site specific stack conditions, evaluating extractive as well as in-situ measurement techniques, and the requirements for low-level calibration standards.

4. Support of HCl CEMS.

Comment 46: Commenter 17622 states the proposed rule suggests that using a compliance approach for DSI of setting injection rate operational limits based on performance testing. According to the commenter, because this approach could result in operators setting injection limits based on performance testing with a higher reactivity sorbent and later substituting a lesser quality sorbent, compliance with the HAP limit could be jeopardized. To avoid this potential issue the commenter recommends the use of CEMS technology to facilitate ongoing HCl emissions compliance. The commenter also recommends at a minimum, if injection rate limits are utilized, reagent reactivity should also be specified.

Comment 47: Commenter 17756 supports the EPA's selection of HCl as a surrogate for the other acid gas HAP. The commenter also agrees with the EPA's proposal to allow EGUs the option of meeting an alternative SO_2 limit, if a unit uses a CEMS device to demonstrate compliance with SO_2 limits. According to the commenter, as drafted, proposed section 63.9991(a)(1)(i) limits the units that can comply with an alternative SO_2 limit to those that have "wet or dry FGD technology installed on the unit."

Response to Comments 46 - 47: The EPA notes the commenter's support for use of an HCl CEMS. As for the reagent reactivity concern, the general requirements for testing require that the tests be conducted under normal conditions, which would include using the same quality sorbent during testing as is used during operations. This type of deliberate violation of the regulations is considered unlikely as a general concern, and will be best handled through effective compliance oversight and no change to the rule is necessary. The EPA also acknowledges the support for the SO_2 alternate equivalent standard option where that applies.

5. Additional concerns.

Comment 48: Commenter 16513 notes that PSEG Bridgeport Harbor 3 is required to comply with the SO_2 emissions rate or fuel sulfur content limits of Regulations of Connecticut State Agencies 22a-174-19a, which PSEG accomplishes by use of low sulfur Indonesian coal. As a result, states the commenter, PSEG Bridgeport Harbor 3 currently meets the Utility NESHAP's SO_2 limit of 0.20 lb/MMBtu for coal-fired EGUs. The commenter states that under the Utility NESHAP, a unit with acid gas controls is not required to install and operate an HCl CEMS. The commenter suggests the EPA clarify whether or not the use of low sulfur fuel would qualify as an acid gas control. The commenter believes if so, PSEG Bridgeport Harbor 3 may forgo the installation of HCl CEMS.

Response to Comment 48: The use of the SO_2 alternate equivalent standard option applies only where an FGD is in use, because that control device ensures adequate acid gas control, and the monitoring of SO_2 ensures proper operation of the control device. In the situation described, without an FGD installed, the unit would not qualify for the SO_2 alternate equivalent standard and must meet the HCl limit. The source can demonstrate compliance using an HCl CEMS or periodic HCl testing.

Comment 49: Commenter 17718 believes that within the proposed regulatory language of 40 CFR 63.10006, there does not appear to be an option for reduced HCl performance testing requirements on coal-fired units with non-HCl controlled bypass stacks. The commenter identifies a facility that is currently configured to send its emissions to a common wet FGD shared with Unit 1 and 3 at the same facility. The common emissions are then emitted through a common stack. The commenter states that all three units are affected coal-fired units designed to burn greater than 8,300 BTU/lb coal, but Unit 2 is also configured and permitted to utilize a bypass stack. According to the commenter, within the proposed language of 40 CFR 63.10010(a)(4), it appears the facility's bypass stack would be required to install similar monitoring systems as the main common stack, but without FGD technology on the bypass stack, it appears that the current 40 CFR part 75 SO_2 CEMS located on the bypass stack could not be used for compliance determinations as a surrogate for HCl. Furthermore, states the commenter, even if the company desired to install an HCl monitor on the dry stack to monitor emissions, it would still be required to conduct performance testing every month because there apparently is not an option to allow HCl monitoring under 40 CFR 63.10006(i)-(k) to cover a non-HCl controlled unit/stack.

Response to Comment 49: The EPA has modified the requirements for monitoring a bypass stack. Under the final rule, the installation of a monitor on a bypass stack is not required.

Comment 50: Commenter 17881 suggests section 63.10011 (b)(1), relating to establishment of a maximum chlorine fuel input, should only apply to units which are not complying with the SO_2 surrogate or are not relying on an HCl CEMS.

Response to Comment 50: Under the final rule, no fuel input operating limits apply. The source may be required to conduct a new performance test where there is a significant change in fuel use that could result in emission increases.

Comment 51: Commenters 17724 and 17876 state that the CEMS the facility installed in preparation to CAMR have significant reliability and operational issues (Hg, PM, HCl). Commenters 17724 and 17876 state that the EPA has left the long-term operational problems such as calibration gases to industry and there are not accurate and reliable monitoring methodologies for demonstrating. Commenters 17724 and 17876 state the EPA purports to provide compliance flexibility while in reality there is very little flexibility in light of the problematic and unproven nature of these monitoring technologies.

Commenter 17736 states the EPA cannot rely on unproven HCl CEMS, that HCl CEMS are not commercially available to measure HCl emissions from coal-fired EGUs, and no HCl CEMS were used to collect the data the EPA used to establish the HCl standard.

Response to Comment 51: The agency disagrees with the commenters. As mentioned elsewhere, the agency finds that the operation and maintenance issues for the CEMS mentioned are no different than for other CEMS now in wide use and acceptance by the industry. The agency is aware that the calibration gas issue is to be rectified well in advance of the rule's compliance date. The agency notes that the rule is quite flexible with respect to compliance demonstration, containing numerous choices for compliance, including the use of emissions testing alternatives for those EGU owners or operators who remain concerned over use of CEMS or PM CPMS. The agency notes that FTIR CEMS exist now and can be used to measure HCl emissions continuously, that the HCl emissions limit was developed from emissions testing and has been adjusted to be appropriate for measurement with HCl CEMS, and that emissions testing options to demonstrate compliance exist for those EGU owners or operators who choose not to use CEMS.

5A10 - Testing/Monitoring: CEMS, General

Commenters: 15678, 16849, 17191, 17197, 17265, 17283, 17316, 17402, 17620, 17623, 17627, 17638, 17655, 17677, 17681, 17716, 17718, 17722, 17725, 17730, 17731, 17740, 17757, 17758, 17767, 17770, 17772, 17774, 17775, 17776, 17781, 17796, 17800, 17805, 17816, 17820, 17821, 17856, 17871, 17873, 17877, 17881, 17885, 17902, 17913, 17928, 18014, 18015, 18031, 18037, 18428, 18443, 18449, 18539, 19032, 19033, 19041, 19114, 19120, 19121, 19122, 19536, 19537, 19538, 18023

1. Support for the PM CEMS, HCl CEMS and Hg CEMS.

Comment 1: Several commenters (15678, 17722, 19032) support the EPA requirements of installing PM CEMS, HCl CEMS and Hg CEMS to demonstrate continuous compliance with the emission standards.

Comment 2: Commenter 17283 supports the EPA that monitoring is an integral part of emission controls and that enhanced monitoring should be encouraged.

Comment 3: Commenters 17402 and 17620 support electronic reporting similar to the 40 CFR Part 75 ECMPS process.

Comment 4: Commenter 17740 supports the EPA that the Hg monitoring requirements established by the CAMR are sufficient and appropriate requirements for the EGU MACT.

Response to Comments 1 - 4: The EPA appreciates the commenters' support for various provisions involving CEMS. The final rule builds on the proposed provisions and clarifies what CEMS are allowed to demonstrate compliance, whether Hg, HCl, HF, or SO_2, as well as how to report that CEMS data using ECMPS. In addition, upon request from a source owner or operator, the agency will consider allowing use of multiple metals CEMS for non-Hg metals. Until a method and performance specification for multiple metals CEMS is promulgated, source owners or operators wanting to request their use should consider having their applications consistent with the draft multiple metals CEMS method and performance specifications located at the following internet address: < http://epa.gov/ttn/emc/prelim/otm19.pdf>.

Given the low non-Hg metals and PM emissions limits and possible difficulties in using PS 11 to certify PM CEMS at those low levels, the rule no longer requires the use of PM CEMS. Rather, PM CPMS, in which a PM detecting instrument is used as a parameter monitor is contained in the rule. Continuous parametric data from the PM CPMS signal will be collected and reported to the agency's central data exchange. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11.

2. Opposition based on testing requirements.

Comment 5: Commenter 16849 states that the proposed rule does not include provisions to use the 40 CFR Part 75 "conditionally valid data procedures." For example, states the commenter, if a CEMS fails a linearity check, the CEMS remains out-of-control until the successful completion of a subsequent linearity check, and this would require the operator to invalidate the 40 CFR part 75 conditionally valid data (for SO_2, CO_2, O_2, or flow monitors) for EGU MACT recordkeeping and reporting purposes.

According to the commenter, a clearer approach would allow quality-assured data from a CEMS certified and operated in accordance to 40 CFR part 75 to be used for compliance with the exception of bias-adjusted and missing data.

Response to Comment 5: For the CEMS data that will be reported through ECMPS, the EPA has added provisions to harmonize these reporting elements so that the data are reported in a consistent manner, including conditionally valid data procedures. The exceptions are that no missing data or bias provisions in part 75 are applied for purposes of complying with these standards.

3. Opposition based on limitations to the technologies.

Comment 6: Commenter 16849 states that there are known limitations to the technologies available to monitor the surrogate HAP and provides the following details:

According to the commenter, Hg CEMS are difficult to maintain and accuracy is questionable at low Hg levels in conditions seen at utility plants. The commenter states that the NSPS limit is so restrictive that utility plants cannot meet the proposed limits and control equipment vendors will not guarantee the limits. According to the commenter, the EPA did not take into consideration the variability of Hg content in coal when setting the low limits for Hg. The commenter states that in order to represent coal variation, a better solution would be to use a requirement such as the Illinois Hg removal limit of 90% which is based on a 720 hour (30-day) rolling average of 1-hour readings and does not rely on a set maximum limit over 30 days as the proposed limit. According to the commenter, Hg analyzer performance has been so unpredictable that utility companies that have continued the use of the CEMS for state requirements are contemplating the replacement of CEMS with sorbent traps for the NESHAP. The commenter states that the EPA has not publicly released NIST Traceability protocols, and early elemental Hg Vendor Prime calibrator certifications exhibited poor accuracy and precision.

Response to Comment 6: The EPA disagrees. The EPA does not believe a percent reduction requirement averaged on a 30-day rolling basis would be more readily monitored than a 30-day rolling average emission limit. In addition, as stated elsewhere, the EPA questions the legality of a percent reduction standard in light of court precedent and we do not have sufficient information to set such a standard even if we believed it was legally available. Sorbent trap monitoring is allowed if a source owner or operator chooses to use that monitoring option. The interim NIST traceability protocols have been publically released and represent the results of a collaborative process for establishing protocols amongst the affected stakeholders for Hg CEMS monitoring.

Comment 7: Commenter 16849 states that there are known limitations to the technologies available to monitor the surrogate HAPS and provides the following details:

According to the commenter, PM CEMS are difficult to maintain and the NESHAP proposes a hybridized reference method, mixing EPA Method 5 and 5B. The commenter states that using total PM for the MACT metals limit surrogate and then setting the filterable PM limit based on the performance test does not work nor allow for a compliance margin. The commenter states that the NESHAP requires maintenance of the PM concentration at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the total PM emissions limitation, and the performance testing for total PM includes both filterable and condensable PM which would establish the plant or unit limit. The commenter states that since the PM CEMS only measures filterable PM, the margin of compliance for the unit or plant would be the amount of total condensable PM. The commenter states that the EPA identifies that EGUs using PRB as a fuel without wet FGD technology have very low condensable PM emissions. According to the commenter, this method establishes an enforceable limit but does not provide a reasonable margin of compliance and artificially changes the limit established in the rule. The commenter states that low limits set during initial performance testing reflect capabilities of new equipment running at steady-state, maximum efficiency, and these conditions will not be achievable as equipment begins to age. Commenter 16849 requests that the performance test requirement be removed, using the RATA to verify the CEMS and the CEMS be the compliance measure based on the 12-month average. According to the commenter, the limit should be set at 0.03 lb/MMBtu, not based on performance testing. Commenter 16849 states that with the addition of PM CEMS on all units, the requirement for opacity CEMS is no longer needed, and PM CEMS should be used to demonstrate compliance for opacity.

Response to Comment 7: The final rule adjusts the manner in which PM instruments are used to determine and monitor filterable PM as an operating limit for non-Hg metals. The rule establishes emissions testing based on filterable PM only, not total PM. The rule also provides for use of PM instruments as CPMS. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11. As for opacity requirements, the EPA disagrees that these MACT standards can undo all prior opacity standards for EGUs under all programs. The EPA will evaluate the extent to which opacity monitoring may no longer be needed as it reviews existing federal standards for affected units, including considering how particular sources choose to operate their PM instruments (e.g., as PM CPMS or PM CEMS), and will make any appropriate adjustments as part of that future, regular review. States may wish to consider how instrumentation in this rule could be useful in evaluating requirements for their own opacity standards.

Comment 8: Commenter 16849 states that there are known limitations to the technologies available to monitor the surrogate HAPS and provides the following details:

According to the commenter, vendors are not assuring the abilities of HCl CEMS, and these monitors have no record in the utility industry. The commenter states that currently no performance test is available for HCl.

Comment 9: Commenter 17191 states that Table 15 of the docket entry EPA-HQ-OAR-2009-0234 of the regulation shows that there is no alternative option of using SO_2 CEMS data as a surrogate for acid gas compliance monitoring for existing IGCC units. The commenter states that the only alternative for compliance is HCl CEMS installation. Commenter 17191 notes that the HCl monitoring system is untested technology for IGCC systems.

Comment 10: Commenter 17402 supports the CEMS requirements outlined in the proposed rule, so long as the technologies have been proven in the field, like SO_2 monitors and Hg sorbent traps, and unlike filterable PM monitors, continuous Hg monitors, and HCl CEMS.

Comment 11: Commenter 17677 disagrees with the EPA regarding high frequency emission testing requirements or PM CEMS due to difficulties in certification at very low emission levels.

Comment 12: Commenter 17757 states that there is no effective CEMS for Hg. According to the commenter, the HCl CEMS are not commercially available or adequate for in-stack measurements. Commenter 17757 disagrees with the EPA establishing CEMS standards about which there is limited experience in the industry and for which the technology has not yet been commercially developed. Commenters (17757, 19033, 19041) state that it is unclear whether installing and operating CEMS for the regulated HAP and HAP surrogates eliminates the obligation to also monitor compliance with operating limits/parameters on control equipment based on a performance stack test. According to the commenters, a properly installed and calibrated CEMS should suffice. Clarification on this point is necessary.

Comment 13: Commenter 18023 states that the EPA must provide reasonable continuous compliance requirements for Hg and other HAP and eliminate requirements for undemonstrated or unreliable technologies such as HCl CEMS and PM CEMS.

Comment 14: Commenters 17800 and 17902 state that while CEMS for Hg and PM are available commercially, EGUs do not have experience in their operation and maintenance on a long term basis. Hg CEMS are not reliable and require two to three times the effort to maintain as typical SO_2 or NO_X CEMS. According to the commenters, further testing and verification of the of the required CEMS equipment at utility sites need to be conducted before they should be used.

Response to Comments 8 - 14: These brief comments raise a variety of issues that generally have been addressed in response to other more detailed comments. The EPA is maintaining the proposed requirements to use CEMS where appropriate. If a source owner or operator does not choose to use an HCl CEMS in situations where the SO_2 alternative is not permitted, HF CEMS, or PM CPMS, the rule provides for a periodic stack testing alternative. If a source owner or operator does not choose to use an Hg CEMS, the rule provides for a sorbent trap alternative. Apart from PM CPMS, operating parameter monitoring requirements no longer exist in the rule. The EPA disagrees that Hg CEMS and PM CEMS are unproven technologies. See response to more detailed comments in other sections of this document on those issues.

4. Opposition based on operating limit requirements.

Comment 15: Numerous commenters (17197, 17623, 17627, 17716, 17722, 17725, 17731, 17740, 17757, 17770, 17774, 17775, 17776, 17800, 17805, 17816 17820, 17871, 17877, 17885, 17902, 18023, 17913, 18014, 18015, 18031, 18037, 18443, 18539, 19033, 19114, 19122, 19536, 19537, 19538) request that the EPA remove the operating limit requirements for facilities that utilize CEMS to demonstrate compliance. According to the commenters, this will reduce the cost and administrative burden of the rule without sacrificing human health or environmental benefits, and the CEMS will continuously monitor the level of emissions and document the source's compliance. The commenters state that requirement to demonstrate compliance in a second form through an operating limit is burdensome and unnecessary. According to the commenters, the EPA should remove requirements to test for the underlying pollutants being controlled through a surrogate because such tests are redundant and unnecessary for compliance with the proposed utility MACT.

Comment 16: Commenters 19120 and 17881 request clarification of the applicability of monitoring and operating limits to units using CEMS for compliance monitoring.

Comment 17: Several commenters (17730, 17758, 17775) disagree with the EPA requirements for sources to establish compliance with the non-Hg metal limits using total PM as a surrogate and PM CEMS as the measurement tool, with the HCl limit using HCl CEMS or an SO_2 CEMS for ongoing compliance, or with the Hg limit using a Hg CEMS or a sorbent trap system to also comply with an operating load limit or with control device operating parameter limits for PM, HCl, or Hg controls.

Comment 18: Commenter 17775 states that the EPA provides no data or discussion to justify chosen control device operating parameters, which are not in most cases sufficiently connected to emissions to justify imposing enforceable limits.

Comment 19: Multiple commenters (17627, 17740, 17770, 17776, 17816, 18014, 18015) state that the EPA should amend the regulatory language in section 63.10007(c) to make it clear that fuel sampling and operating parameter limits do not apply when either all of the regulated HAP or their surrogates are continuously monitored by a CEMS.

Comment 20: Commenter 19033 recommends that section 63.1008(a) be amended to require performance fuel analysis tests, if the regulated pollutant or specified surrogate emissions are not continuously measured by a CEMS.

Comment 21: Commenter 18023 proposes that operating limits should be a trigger for maintenance or inspection only.

Comment 22: Commenter 17877 states that operating limits or parameters should not be required on emission control devices where compliance is demonstrated by CEMS and that operating limits should not be established based on initial performance testing.

Comment 23: Commenter 17928 states that stack testing is unnecessary to assure compliance if a unit installs or uses CEMS.

Response to Comments 15 - 23: The final rule clarifies that where a CEMS is used for a given pollutant (including an alternate equivalent standard in the case of SO_2) then no parameter monitoring is also required for demonstrating continuous compliance with the emission limit for the applicable pollutant. The final rule also clarifies that sources do not have to test for a pollutant where the source is meeting a surrogate emission standard (such as filterable PM for non-Hg HAP). As mentioned in other responses, with the exception of PM CPMS and in limited cases, site-specific parameters for liquid oil-fired units, the remaining fuel analysis, operating limit and parameter monitoring comments, are moot, for the rule no longer requires operating limits. For the EPA's response to those comments which oppose the manner in which operating parameter limits are set, please see responses to comments under section 5A05 in this document. As noted elsewhere, no operating parameter requirements apply when a CEMS is used to demonstrate compliance for an applicable pollutant.

5. Opposition based on averaging times.

Comment 24: Commenter 16849 recommends that averaging times for demonstrating compliance with the Hg limits be increased to a 365-day rolling average due to variability in coal quality, varying Hg content, removal equipment, and Hg CEMS monitor accuracy.

Comment 25: Commenter 17197 supports the proposed "30-boiler operating day rolling average" calculation methodology based on averaging all of the valid hourly averaged measurements during the preceding 30 boiler operating days. According to the commenter, if compliance is based on daily periods rather than hourly periods, a single (abnormally high or low) hourly measurement could be the basis of a daily period that could improperly bias the resulting 30-day average. The commenter states that using hourly averages as the basis for the 30-day boiler operating day rolling averages removes the potential for skewed results from days containing only a few unit operating hours and consequently yields representative emission rates for the 30-day compliance demonstration period.

Comment 26: Commenter 17740 does not support compliance demonstration with the tested average PM value using a 30-boiler operating day PM average.

Comment 27: Commenter 17402 states that since the rule does not propose a cap-and-trade program, units should not be required to collect a monitored value for each operating hour.

Response to Comments 24 - 27: The final rule maintains the 30-day rolling average using hourly values (unless a source chooses to apply emissions averaging of Hg emissions for multiple units in the EGUs designed for coal ≥ 8,300 Btu/lb subcategory). This averaging period enables short-term variability to be averaged out, and this averaging period is consistent with the periods already used in subpart Da of the NSPS. Sources are required to monitor during all operating periods when continuous monitoring is used to demonstrate compliance. See the preamble for discussion of alternative averaging times.

6. Opposition based on bias adjustments.

Comment 28: Several commenters (17881, 17796, 18023) support eliminating the bias adjustment for mercury, HCl, and PM CEMS since it is believed that bias adjustment of data has only been utilized with trading system based rules where mass emissions are being totaled.

Comment 29: Commenter 18023 states that bias can cause both over-and-under reporting. The longer averaging time should alleviate the need for bias adjustment.

Comment 30: Commenter 17767 states that unless the EPA is prepared to allow for the low bias of emissions data as well as high, it is best to follow the proposed rule and remove the Part 75 Bias Test for Hg, HCl, and PM CEMS.

Response to Comments 28 - 30: There is no bias adjustment factor applied for purposes of this rule.

7. Opposition based on compliance requirements.

Comment 31: Commenter 16849 disagrees with the EPA about the ability of Hg CEMS to reach compliance within the first 30 days of operation. According to the commenter, with the needed adjustments and repairs to Hg CEMS and the additional operation of multiple control devices, plant personnel will need at least 180 days to optimize control and monitoring equipment.

Response to Comment 31: For existing units, the final rule requires sources to demonstrate compliance within 180 days after the date 3 years after the effective date of the final rule. Such an extended period provides ample opportunity for the types of adjustments suggested by the commenter. For new units, the rule likewise provides up to 180 days for demonstrating initial compliance.

Comment 32: Commenter 17716 disagrees with the EPA about showing on-going compliance by combining CEMS data with non-CEMS data to demonstrate compliance.

Response to Comment 32: The comment is moot, as the rule no longer contains a total PM limit, no longer requires use of PM CEMS for filterable PM, and no longer requires use of Method 202 to determine condensable PM.

Comment 33: Commenter 17758 states that the purpose of the fuel input limits is to ensure that EGUs that are not using CEMS or sorbent trap monitoring systems repeat the relevant performance test if their fuel characteristics change such that compliance with the applicable limit at the current level of control is no longer assured. According to the commenter, since all EGUs are required to demonstrate initial compliance with each emissions limit through performance testing, and the proposed rule defines performance testing to include the first 30 operating days of CEMS data, the proposal appears to require that EGUs meet fuel input limits regardless of the performance testing option that they choose. The commenter states that there is no logical rationale for requiring sources that establish compliance with the non-Hg metal limit using PM as a surrogate and PM CEMS, with the HCl limit using HCl CEMS or an SO_2 CEMS, or with the Hg limit using Hg CEMS or a sorbent trap system to also comply with fuel input limits for metals, chlorine or Hg.

Response to Comment 33: The comments are moot because the rule no longer requires fuel analysis or operating limits.

Comment 34: Commenter 17775 notes that the EPA does not propose separate continuous compliance requirements for HF CEMS.

Response to Comment 34: Section 63.10010(d) addresses operating requirements for HF CEMS.

Comment 35: Several commenters (17800, 18015, 18037) state that compliance testing and monitoring requirements that include periodic emission testing, other performance testing and CEMS are unnecessarily restrictive and expensive to implement, perform and operate. According to the commenters, the regulations for Hg CEMS had numerous unresolved issues related to accuracy, calibration standards, and quality assurance provisions, and the EPA should allow time for development of performance specifications and, field testing and verification of the accuracy and precision of HCl monitoring equipment at utility sites before they are required for compliance purposes.

Response to Comment 35: For comments on technical aspects of HCl and Hg monitoring, see the specific responses to comments on those technologies in other sections of this document. The EPA disagrees with granting states flexibility to establish compliance plans for sources. This is a federal rule, which provides flexibility to sources to select appropriate monitoring for their facility. In the event the source believes an alternative monitoring method should apply, the part 63 provisions establish a method to request alternative monitoring, and the EPA and the states have established procedures for handling such requests in the event implementation of a specific NESHAP is delegated to a state agency.

Comment 36: Commenters 17805 and 17816 state that there is no logical reasoning for requiring sources to establish parametric limits for compliance at units already demonstrating compliance with CEMS.

Response to Comment 36: The comments are moot because the rule no longer requires fuel analysis or operating limits.

Comment 37: Commenter 17856 states that due to the very low concentrations of Hg in stack gases, any little flaw in the precision or accuracy of the monitor could lead to an inaccurate compliance determination. The commenter states that the uncertainty associated with the use of these technologies further illustrates the need for provisions within the rule allowing a state to develop compliance plans tailored to a particular unit's operations. According to the commenter, states need monitoring requirements with flexible options for compliance plans, such as fuel sampling and analysis, emission control monitoring, and the installation of CEMS, to provide sufficient assurance that actual emissions limits are being met.

Response to Comment 37: For comments on technical aspects of HCl and Hg monitoring, see the specific responses to comments on those technologies in other sections of this document. The EPA disagrees with granting states flexibility to establish compliance plans for sources. This is a federal rule, which provides flexibility to sources to select appropriate monitoring for their facility. In the event the source believes an alternative monitoring method should apply, the part 63 provisions establish a method to request alternative monitoring, and the EPA and the states have established procedures for handling such requests in the event implementation of a specific NESHAP is delegated to a state agency.

Comment 38: Commenter 17881 states that the EPA needs to clarify whether fuel analysis and/or the establishment of operating limits apply in those cases where a CEMS is used to directly measure the HAP or an associated surrogate.

Response to Comment 38: The comments are moot because the rule no longer requires fuel analysis or operating limits.

8. Opposition based on monitoring requirements.

Comment 39: Commenter 17740 recommends that the EPA eliminate fuel sampling and parameter monitoring for an EGU which meets the specified emission limits as demonstrated through use of a CEMS and states the following:

a. The EPA has not provided a rational justification for additional requirements to Part 75. *See* 40 CFR section 63.10010.

b. The EPA should allow at least 1 year for sources to install and certify an HCl CEMS and should require HCl testing once every four unit operating quarters, but no less than once every eight calendar quarters.

Comment 40: Commenter 17758 states that the EPA does not have a performance specification that is specific for non-FTIR-based HCl monitors. The commenter states that table 5 of the docket entry EPA-HQ-OAR-2009-0234 lists PS 6 as an applicable performance specification, but PS 6 is written for the certification of systems used to measure pollutant emissions in units of mass per unit of time. The commenter states that the EPA protocol gases are not widely available and are expensive relative to traditional CEMS calibration gases. According to the commenter, lowest available concentrations are significantly higher than proposed limits. Commenter 17758 recommends that the EPA allow use of SO_2 monitors installed downstream of a wet or dry scrubber or DSI system to comply with the HCl monitoring requirements.

Comment 41: Commenter 17775 states that the EPA should describe why EGUs need to monitor control device parameters for meeting fuel input levels and that there is no discussion at all of the proposed fuel input levels in the docket entry EPA-HQ-OAR-2009-0234.

Response to Comments 39 - 41: As stated elsewhere in response to more detailed comments, source owners or operators who use CEMS to demonstrate continuous compliance are not required to monitor operating parameters or fuel for the same pollutant, as fuel analysis is no longer required and, apart from PM CPMS, operating limits are no longer required. A source can opt to use an SO_2 CEMS instead of an

HCl CEMS in specific circumstances, and can use emissions testing in lieu of an HCl CEMS. The EPA also intends to promulgate a performance specification for HCl CEMS prior to the compliance date of this rule, at least with respect to the compliance date for existing sources.

Comment 42: Commenters 17716 and 18449 state that section 63.10021(a)(10)(ii) does not include a reference to CO_2 contrary to the requirements in section 63.10010(b) which allow the use of O_2 or CO_2. According to the commenters, the majority of Part 75 affected coal-fired units utilize dilution-extractive CEMS which are equipped with CO_2 analyzers, and dilution-extractive CEMS cannot measure O_2 as a diluent.

Response to Comment 42: The final rule addresses this oversight.

Comment 43: Commenter 17881 states that in cases where an EGU elects to calculate annual Hg emissions based upon the average measured Hg concentration and measured exhaust flow rate, the EPA has already granted the use of the default moisture content values for the determination of exhaust gas moisture content in 40 CFR part 75, section 75.11(b)(1).

Response to Comment 43: The final rule allows for moisture defaults as proposed. Given the lack of defaults for oil-fired units, we have added an option for sources to petition for an alternative unit-specific default in those cases.

Comment 44: Commenters 17881 and 19114 state that the proposed regulation referring to "fuel-specific CO_2 concentration" in section 63.10005(l) has following flaws:

a. According to the commenters, the proposed rule does not contain any such default CO_2 concentration values and does not reference another regulation containing such values, and it is hard to believe that the EPA intended for each regulated source to develop a custom "fuel-specific CO_2 concentration" based upon the equivalent O_2 diluent cap and the fuel or fuels being fired.

b. According to the commenters, these provisions do not distinguish between boilers and the combustion turbines used in IGCC technologies; boilers and combustion turbines are fundamentally different combustion processes and operate at very different levels of excess air (which in turn impacts the diluent gas concentrations).

c. According to the commenters, the proposed rule language is not clear on when the diluent cap values should be applied; it simply states that they should be applied during periods of startup and shutdown (which are not defined in the proposed rule, and are only generically defined in section 63.2). The commenters state that under 40 CFR Part 75, the diluent cap values are simply applied whenever the 1-hour average diluent concentrations fall below the applicable diluent cap values (without any qualification that the unit must be in startup or shutdown modes). Outside of periods of startup and shutdown, state the commenters, it is hard to envision any other circumstances which would cause the diluent concentrations to fall below the diluent cap values.

Response to Comment 44: Given the changes from proposal, these provisions are no longer relevant and do not appear in the final rule.

Comment 45: Commenter 18014 states that EGUs that install a CEMS should not be required to provide further assurance of compliance with the emissions standards. According to the commenter, such additional monitoring is redundant and creates an unnecessary burden on these sources and as such should be removed from the rule.

Response to Comment 45: The EPA agrees, and the final rule clarifies this approach.

9. Opposition based on QA/QC requirements.

Comment 46: Several commenters (17716, 17881, 18014) state that the O_2 and CO_2 CEMS requirements in section 60.10010(b) should refer to 40 CFR Part 75 in lieu of the alternate requirements specified in Appendix A to subpart UUUUU of the docket entry EPA-HQ-OAR-2009-0234. According to the commenters, the following text should be added to Table 5 of the docket entry EPA-HQ-OAR-2009-0234, as applicable: "Alternatively, for an affected source that is also subject to the O_2 or CO_2 monitoring requirements of 40 CFR Part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality assure the data from an O_2 or CO_2 CEMS according to 40 CFR Part 75 in lieu of the procedures in paragraphs b(1) through b(3) of this section."

Response to Comment 46: The final rule includes language comparable to the requested language for an O_2 or CO_2 CEMS. For the SO_2 CEMS, see responses to similar comments under 5A08 of this document.

Comment 47: Commenter 17716 disagrees with the EPA about additional QA/QC requirements for use of SO_2 CEMS. The commenter states that although use of SO_2 CEMS is allowed for compliance demonstration, the requirements state that the operator "must perform the 7-day calibration error test required in Appendix A to 40 CFR Part 75 on the SO_2 CEMS whether or not it has a span of 50 ppm or less." According to the commenter, because the majority of 40 CFR Part 75 affected sources have completed initial certification years ago and have been collecting "quality-assured" data for years, the benefit to this requirement is not apparent.

Response to Comment 47: This requirement has been removed in the final rule based on comments, and we do not think it is appropriate to include the provision pending further review of the technical issue by EPA's monitoring groups.

Comment 48: Commenters 17820 and 17821 state that there are already other monitoring requirements for units required to report under Part 60, and there have been attempts to harmonize those rules to reduce confusion and cost. According to the commenters, the Part 60 rules, like these proposed rules, are not as detailed as Part 75 and could lead to inconsistencies in data quality between operators. Adding additional, different, and possibly conflicting requirements for this rule will cause additional confusion, increase downtime, and increase costs with no evidence of any benefit.

Response to Comment 48: The EPA has attempted to harmonize the CEMS requirements under this rule primarily with the Part 75 CEMS requirements that already apply to most of the affected EGUs under this rule.

10. Opposition based on sampling.

Comment 49: Commenter 17316 states that the outlet location for CEMS Probe is not the best location for these probes. The commenter states that the "outlet location" defined as the immediate exit of the boiler, just downstream of the combustion process, is not an appropriate location where a "representative sample" can be collected. Commenter 17316 recommends that "representative samples" should be obtained by locating the probe in the downstream ductwork or in the stack.

Comment 50: Commenter 17655 states that the monitoring requirement for three new monitoring devices in existing smoke stacks threatens stack integrity and adds that the EPA did not consider safety issues associated with drilling additional holes in existing stacks and chimney liners.

Comment 51: Commenters 17775 and 17928 disagree with the EPA requirement for HAP stack testing for EGUs using surrogates, surrogate stack testing for EGUs using CEMS, and surrogate testing for EGUs not relying on surrogates for compliance demonstration.

Response to Comments 49 - 51: In response to comments, the final rule has removed all requirements for duplicative testing of a HAP and the applicable surrogate. Facilities complying with a surrogate standard will conduct the performance test for that standard, and not for the corresponding HAP emission limit (and vice versa).

Comment 52: Commenter 18014 states that it is unclear as to whether EGUs that fire a single type of fuel are exempt from all fuel sampling and analysis requirements.

Response to Comment 52: This comment is moot because the fuel analysis requirements are not included in the final rule.

Comment 53: Commenter 17902 states that installation of additional CEMS for PM and HCl requires significant structural modifications, such as:

a. Installation of additional ports (to install the sampling probe);

b. Stack platforms (additions or modifications to existing platforms to access new monitoring equipment);

c. Shelters (to house climate controlled equipment);

d. Electrical instrumentation (to power shelters, heat probes, etc); and,

e. Communications systems (needed fiber optics, Ethernet to communicate with existing computer programs).

Response to Comment 53: The addition of new monitoring equipment may require additional modifications to existing CEMS infrastructure, although the EPA questions whether the changes are significant structural modifications in light of the emission control requirements of this rule. To the extent a source believes these changes are too significant, the source can conduct periodic stack testing as an alternative to either a PM CPMS or an HCl CEMS.

11. Need clarification on operational limitations.

Comment 54: Commenter 17800 states that the compliance with MACT standards that have numerical limits should be based on what is being measured in the stack and not on how the unit is being operated. Use of CEMS should preclude operational limits. According to the commenter, the operational requirements in Table 4 of part 63 subpart UUUUU are unnecessary, requiring unneeded record keeping that does not improve compliance and should be eliminated from this rule. The commenter states that if the unit chooses to install and properly operate and maintain CEMS for filterable PM, Hg and HCl, these operating limits are unnecessary. According to the commenter, once the CEMS are certified and recording quality assured data, these systems determine the unit's compliance status. The commenter states that the EPA should clarify when CEMS are being used for compliance, operational limitations on unit load and the applicable control equipment are unnecessary as well as the reporting requirements in section 63.10031 pertaining to those operational requirements.

Response to Comment 54: Where a CEMS is used, EPA largely agrees. As discussed in detail elsewhere in this response to comments document, EPA has eliminated all operating limits in Table 4, with the exception of an operating limit associated with a PM CPMS, and in limited cases, site-specific parameters for liquid oil-fired units. In consideration of the PM emissions limit and the burden associated with certifying a PM CEMS via PS11, the agency decided to allow use of a PM instrument not as a CEMS but as a CPMS. The operating limit for use in conjunction with a PM CPMS functions in the same manner as parameter monitoring from other rules. The highest hourly average of the PM CPMS signal produced over three test runs is used as the operating limit, and that value becomes averaged over a rolling 30 boiler operating day average. The final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach (see the final preamble for further discussion). In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11.

12. Requirements for bypass stacks.

Comment 55: Commenter 17718 states that within the proposed regulatory language of section 63.10006, there does not appear to be an option for reduced HCl performance testing requirements on coal-fired units with non-HCl controlled bypass stacks. The commenter states that within the proposed language of section 63.10010(a)(4), it appears that a bypass stack would be required to install similar monitoring systems as the main common stack. According to the commenter, without flue grade sulphurization technology on the bypass stack, it appears that the current 40 CFR Part 75 SO_2 CEMS located on the bypass stack could not be used for compliance determinations as a surrogate for HCl. The commenter states that even if the company desired to install an HCl monitor on the dry stack to monitor emissions, it would still be required to conduct performance testing every month.

Comment 56: Commenters 17772 and 17873 state that PM CEMS do not operate properly during startups and shutdowns. According to the commenters, PM CEMS are not calibrated under startup or shutdown conditions, nor are they calibrated using the changing fuel mix (e.g., moving from 100 percent oil to 100 percent coal) associated with start-up, and values during these times are not valid for compliance purposes. If a bypass stack is predominately used during startup and shutdown, state the commenters, there should be no requirement to install a PM CEMS. The commenters state that the EPA has the discretion necessary to regulate PM through a work practice standard; instead of requiring costly and duplicative monitoring equipment to measure intermittent emissions that occasionally flow through bypass stacks, the EPA should develop work place standards that would put parameters around how often and when bypass stacks can be employed.

Comment 57: Commenter 17781 states that the periods of EGU startup and shutdown resulting in FGD bypass, as well as reasonable periods of FGD malfunction which are addressed in an appropriate manner, should not disqualify an EGU from using the SO_2 surrogate for HCl.

Response to Comments 55 - 57: The final rule provides an option to monitor a bypass stack or to treat any hour in which the unit bypasses the main stack and fails to collect quality-assured data as an hour of monitoring downtime. The EGU owner or operator remains subject to the 30 boiler operating day rolling average during bypass operations.

13. Opposition based on maintenance requirements.

Comment 58: Commenters 17775 and 17800 state that the EPA did not account for the fact that EGUs need to perform maintenance, in addition to required QA/QC, in order to keep monitoring systems running properly. The commenters state that the EPA should recognize this in the 40 CFR part 63 general provisions, which require sources to maintain their monitoring systems and exempts "maintenance periods" from operating requirements.

Response to Comment 58: Normal maintenance activities associated with quality control (not quality assurance) procedures in a source's monitoring plan are exempt as part of the QC exemption provided in the final rule. No additional exemption is necessary.

14. Need for clarification on monitoring, recordkeeping and reporting requirements.

Comment 59: Commenter 17776 states that the EPA needs to clarify the proposed rule that monitoring, recordkeeping, and reporting requirements do not apply for facilities equipped with CEMS. According to the commenter, facilities which use CEMS for monitoring of a regulated pollutant or surrogate should not require fuel sampling, parameter monitoring, or compliance with fuel or operational limits.

Response to Comment 59: The rule does not require monitoring operating limits where a CEMS is used for the applicable standard. If a source has PM control equipment and uses a PM CPMS-based operational limit, no control device monitoring is required. The same is true for SO_2/ HCl controls.

Comment 60: Commenter 17776 states that for PM (Item 1) and HCl (Item 3) in Table 5, references to Appendix A of subpart UUUUU in the "using" column are listed, but Appendix A of subpart UUUU does not address monitoring certification and ongoing monitoring requirements for PM and HCl CEMS.

Response to Comment 60: These cross references have been corrected in the final rule.

Comment 61: Commenter 17725 states that the EGU MACT Rule does not include provisions to use the Part 75 "conditionally valid data procedures." The commenter states that if a CEMS fails a linearity check, the CEMS remains out-of- control until the successful completion of a subsequent linearity check, and this would require the operator to invalidate the Part 75 conditionally valid data (for SO_2, CO_2, O_2 or flow monitors) for the EGU MACT recordkeeping and reporting purposes. According to the commenter, a clearer approach would be to allow quality-assured data from a CEMS certified and operated in accordance to Part 75 to be used for EGU MACT compliance.

Response to Comment 61: The final rule provides for certain Part 75 procedures for the CEMS and sorbent trap monitoring systems used to comply with this rule, including the use of the conditionally valid data procedures.

15. Lack of variability.

Comment 62: Commenter 18014 states that the snapshot nature of performance test data means the results will provide little insight on the true range of boiler variability and the associated effects on emission controls. According to the commenter, the EPA should address the additional variability introduced by the CEMS within the rule. The commenter states that the "apples-to-oranges" contrast of the CEMS versus reference method data (particularly given the current state of PM, HCl and Hg CEMS) provides additional support to use the CEMS data as indicators of performance rather than direct measures of compliance. According to the commenter, since neither the CEMS measurement variability or the plant operational variability that will be an inherent part of the CEMS data will not be reflected in the reference method-based UPL, a separate multiplier should be applied to the UPL (or applied as an additional multiplier to the FVF adjusted floor average) to address for the CEMS/operating variability issue.

Response to Comment 62: The PM monitoring will be used as a PM CPMS and not as a direct compliance method with an emission limit. For the Hg CEMS or sorbent trap monitoring system, and the HCl CEMS, the EPA disagrees. This issue is discussed in more detail in the comment sections directly related to Hg CEMS and HCl CEMS.

16. Missing information.

Comment 63: Commenter 18014 states that the rule does not include the equations for calculating PM or HCl mass emissions; Appendix A only includes equations for Hg.

Response to Comment 63: There is no requirement to calculate PM mass emissions; PM monitoring is a parameter-based approach to ensure compliance with an operating limit. For HCl, section 9 of Appendix B to the final rule provides the appropriate method for calculating emissions in terms of the emission standard.

17. Recommendations.

Comment 64: Commenter 15678 recommends that CEMS need to be certified and recertified according to the EPA proposed procedures, such as Table A-1 on page 25140 of the Federal Register (Vol. 76, No. 85 / Tuesday, May 3, 2011) for the required certification tests and performance specifications for Hg CEMS.

Comment 65: Commenter 16849 recommends that further testing and verification of the accuracy of the required CEMS equipment at utility sites be conducted before they are used for compliance purposes.

Comment 66: Commenter 17191 recommends that the SO_2 monitoring as a surrogate for acid gas HAP be included as an option for IGCCs as it is for other categories that have SO_2 data available.

Comment 67: Commenter 17197 recommends that a footnote be added to Table 5 of the docket entry EPA-HQ-OAR-2009-0234 that states "Daily calculate a new 30-boiler operating day rolling average of all of the hourly CEMs emissions data for the preceding 30-boiler operating days."

Comment 68: Commenter 17265 is requesting clarification of whether CEMS are warranted across-the-board for the HCl source category, and supports retaining a source's option to select CEMS as the monitoring method, but recommends that the QA provisions be further developed to ensure the credibility and accuracy of the data.

Comment 69: Commenter 17283 recommends proposed alternative standards for total or individual metals, including specific language in the final rule allowing enhanced monitoring of these metals with multi-metals CEMS as an alternative to Reference Method 29 measurements and/or PM CEMS and/or Hg CEMS.

Comment 70: Commenter 17283 states that cycle time equal to or less than 15 minutes is currently required for CEMS in various places (Table A-1, Table A-2, and pages 25110-25113) of the docket entry EPA-HQ-OAR-2009-0234 and strongly recommends that these references to 15-minute cycle times be eliminated because, according to the commenter:

a. 15-minute cycle times are not required to evaluate health effects or demonstrate compliance with limits,

b. Reference methods require sampling times of about 4 hours at these low concentrations, and

c. The proposed cycle time is not consistent with PS12 A or Cement MACT rules.

Comment 71: Commenter 17283 recommends that units employing PM CEMS should be exempted from federal and state opacity monitoring requirements.

Comment 72: Commenter 17677 recommends that the EPA must have certifiable methods for source CEMS in order to determine accuracy. According to the commenter, without certifiable methods/procedures, data accuracy cannot be relied upon for compliance determinations.

Comment 73: Commenter 17677 recommends that the EPA clarify the language relating to initial compliance demonstrations for CEMS.

Comment 74: Commenter 17730 recommends that the EPA should provide procedures for averaging actual emissions data from CEMS to determine monthly average weighted emissions and revision of section 63.10009 to include procedures for units using CEMS to calculate average weighted emissions in lieu of compliance with the operating limits for control devices proposed in section 63.10022.

Comment 75: Commenter 17681 recommends that the EPA should allow compliance to be demonstrated based on stack tests and CAM plans.

Comment 76: Commenter 17638 recommends that the EPA allow compliance to be demonstrated based on stack tests and CAM plans other than PM and HCl CEMS.

Comment 77: Commenters (17716, 18014) recommend that the EPA should revise section 63.10007 to indicate that the fuel sampling and operating parameter limits are not required when the applicable HAP (or surrogates) are monitored using a CEMS.

Comment 78: Commenter 17731 concurs that the performance stack testing requirements set out in Table 5 (part 76 CFR 25129-31) should not be required of those EGUs that use CEMS for continuous compliance because the requirements are redundant and burdensome without providing added benefit.

Comment 79: Commenters (17767, 17881, 18428) recommend that it is appropriate that the proposed rule does not require the generation and submittal of missing data substitutions, as the emissions limitations are rate-based and not mass-based.

Comment 80: Commenter 17775 recommends that the EPA should allow use of 40 CFR Part 75 provisions as an alternative for diluent monitoring.

Comment 81: Commenter 17775 recommends that the EPA revise section 63.10010(a) to acknowledge the other monitoring options in the rule (including the option of stack testing with monitoring of operating parameters and, fuel analysis for liquid oil-fired units), or limit applicability of the section to those circumstances where an EGU opts to, or is required to install a CEMS or sorbent trap system.

Comment 82: Commenter 17775 recommends that the EPA should eliminate the redundancy between section 63.10010(a)(4) and Appendix A section 2.

Comment 83: Commenter 17775 recommends that the EPA include provisions similar to 40 CFR Part 75 that allow EGUs that are otherwise using CEMS to report a site-specific default value during bypass in lieu of installing and maintaining CEMS on the bypass stack.

Comment 84: Commenter 17776 recommends that the EPA should revise the requirement to use PM CEMS for demonstrating continuous compliance with the total PM limit. PM CEMS can only analyze for filterable PM per EPA PS 11.

Comment 85: Commenter 17776 recommends that the EPA should allow the use of sorbent trap monitoring systems as another means for continuous monitoring of Hg emissions. Commenter also recommends that the EPA allow annual performance tests for HCl until HCl CEMS technology advances further.

Comment 86: Several commenters (17725, 17820, 18014, 19033) recommend that section 63.10010(b)(5) should be revised to include CO_2, for example, “the average of all of the hourly oxygen or carbon dioxide emissions data for the preceding 30 boiler operating days,” and that section 63.10021(a)(10)(ii) should include a reference to CO_2 records.

Comment 87: Commenters (17718, 18037, 18539) recommend that performance testing should be conducted annually for each of the stacks instead of every other month as currently proposed. According to the commenters, it may not be feasible to complete testing at all units within a monthly or 2-month period due to lack of test crews, unit scheduling, scheduled maintenance, and other considerations.

Comment 88: Commenter 17722 states that the EPA should allow “to-be-approved” monitoring techniques and technologies as part of the final rule. As one example, Commenter is aware of a novel sorbent tube technology that is under development by the University of North Dakota’s Energy and Environmental Research Center (“EERC”), where the sorbent tubes are designed to measure HAP acid gases and non-Hg HAP metals. According to the commenter, EERC is under contract with the Department of Energy to run parallel Method 26 and Method 29 tests later this year, and if these sorbent tubes prove viable, like Hg sorbent tubes, the final EGU NESHAP rule should allow use of this new approved monitoring technology.

Comment 89: Commenters 17821 and 17881 recommend removal of requirements for calculating (and reporting) long-term 30-day rolling averages for O_2 (and CO_2) emissions. O_2 (and CO_2) concentration data are typically used as a diluent gas when using CEMS measurement data to calculate emission rates in terms of lb/MMBtu. According to the commenters, the diluent gas components of these equations under 40 CFR 60 are not averaged into long-term averages; only the emission rate data (lb/MMBtu) are averaged over long-term periods, and these long-term emission rate averages are calculated not from long-term O_2 or CO_2 averages and long-term SO_2 or NO_X averages, but from the hourly emission rate data that is calculated using the hourly diluent gas values.

Comment 90: Commenter 17821 recommends that the EPA allow the use of certified flow monitoring systems to calculate emissions rates when volumetric flow rate is needed. The commenter states that volumetric flow CEMS certified in accordance with 40 CFR 75 are used for reporting purposes already and allowing these data to also be used to calculate mass emissions would provide consistent data.

Comment 91: Commenter 17881 states that the provisions at section 63.10010(b)(4) require that CEMS data be reduced to 1-hour averages according to the requirements in section 63.8(g)(2) and (4). According to the commenter, these data reduction procedures are not fully consistent with the procedures specified at section 60.13(h) and section 75.10(d)(1), and commenter suggests that the preceding data reduction procedures be allowed as alternatives to those which are currently specified.

Response to Comments 64 - 91: The EPA has considered all of these various recommendations in finalizing the proposed monitoring requirements. In general, the final rule builds on the proposed requirements by providing for monitoring continuous compliance with specific standards through the use of an applicable CEMS, or a sorbent trap for Hg, or a PM CPMS for non-Hg metals or PM. Should a source owner or operator elect not to use CEMS or the other instrumental methods, performance testing is required. In revising the proposed rule, the EPA has finalized an approach that builds off the Part 75 requirements wherever possible for CEMS. The EPA believes that the initial and ongoing certification and QA procedures for applicable CEMS are appropriate for ensuring the collection and reporting of quality data. The final rule includes a variety of specific changes to help clarify the use of CEMS versus operating parameter monitoring, calculation of 30-day rolling averages, and other specific issues with the monitoring requirements raised in these brief recommendations and more specific comments on aspects of the proposed standards. Where a source owner or operator wishes to use an alternative monitoring approach, such as a multi-metals CEMS, the source owner or operator may propose such a method under the general provisions in section 63.8(f) of subpart A of part 63.

18. Need for clarifications of rule.

Comment 92: Commenters 17718 and 17881 request that the EPA clarify when the 30-day operating period begins if the systems are already certified (e.g., current SO_2 or PM CEMS being used for 40 CFR Part 75 and/or 40 CFR Part 60 monitoring programs).

Response to Comment 92: The 30-day period will begin on such date as you indicate in your Notification of Intent to conduct a performance test (see section 63.10030(d)). You must complete the initial test within the period specified in the rule.

Comment 93: Commenter 17718 states that the EPA should clarify whether initial testing of the bypass emissions needs to be tested within the 180-day timeframe described in the proposed language and that alternatively, setting a firm testing timeframe on bypass stack emissions seems overly burdensome. According to the commenter, creating emissions (and incurring costs) by switching a unit into bypass mode that would not otherwise have been used simply in order to perform emission testing appears to create unnecessary burden.

Response to Comment 93: Under the final rule, you may elect to monitor the bypass stack or treat hours in which the bypass is used as monitor downtime. The EGU owner or operator remains subject to the 30 boiler operating day rolling average during bypass operations. To report data from any monitoring on a bypass stack, you do need to have a certified monitoring system. Because you can decide to not monitor the stack, there is no requirement that the certification occur in the first 180 operating day period.

Comment 94: Commenters 17718 and 19121 states that in the proposed regulatory language seen in section 63.10005(l), it is mentioned that a "default diluents gas concentration value of 10.0 percent O_2 or the corresponding fuel-specific CO_2 concentration" are to be used during periods of startup or shutdown when calculating emissions in units of "lb/MMBtu" or "lb/TBtu." According to the commenter, the EPA should clarify how to calculate the "corresponding fuel-specific CO_2 concentration."

Response to Comment 94: Because of the revisions related to startup and shutdown provisions, the cited language is no longer applicable.

Comment 95: Commenter 17820 cites that Table 8 states that the source is to convert "hourly emissions concentrations to 30 individual boiler operating mg/dscm values," which suggests that compliance is assessed based on the average of 30 individual daily values but that section 63.10010(g)(5) states that 30-day rolling average is calculated as "the average of all of the hourly particulate emissions data for the preceding 30 boiler operating days." The commenter states that this requirement needs to be clarified.

Response to Comment 95: The referenced language in the proposed rule is not used in the final rule. Provisions in Appendix A and Appendix B to the final rule describe the procedure for calculating 30-day averages where an Hg CEMS, sorbent trap monitoring system, or HCl CEMS are used for compliance. Overall, the language in the final rule ensures a uniform approach for calculating averages from CEMS data and from a PM CPMS.

5A11 - Testing/Monitoring: Disable bias tests for Hg, HCl, and PM CEMS

Commenters: 17718, 17740, 17816, 17820, 17873, 17877, 17881, 17909

1. Support for eliminating bias tests.

Comment 1: Multiple commenters (17718, 17740, 17816, 17820, 17873, 17877, 17909) recommend that the EPA disable the ECMPS Part 75 bias test for Hg, HCl, and PM CEMS. The commenters state that bias adjustment may be appropriate for emissions trading programs to ensure that companies are not under-reporting their emissions and, hence, failing to surrender an adequate number of allowances for compliance purposes, but it is unnecessary for compliance with the MACT standards.

Comment 2: Commenters 17718 and 17816 support the EPA's proposed approach to streamline the continuous compliance requirements for monitoring, reporting, and recordkeeping and urge the EPA to remain open to additional accommodations that are identified in the course of implementing the program.

Comment 3: Commenter 17877 states that eliminating the bias test for these monitors will also reduce the file size, complexity, and time required to maintain and report quality assured data.

2. Other bias test comments.

Comment 4: Commenter 17881 states that the proposed EGU MACT rule appears to be silent on the concept of whether SO_2 missing data substitution under 40 CFR Part 75 would be allowed in the context of 63.10010(e)5. In addition, states the commenter, the concept of bias adjustment factors (BAFs) under 40 CFR Part 75 does not appear to be addressed. According to the commenter, in other cases where the EPA has allowed the use of Part 75 CEMS for compliance demonstrations under other regulatory programs (i.e., 40 CFR Part 60, subpart Da), the EPA has prohibited the use of missing data substitution and BAFs.

Response to Comments 1 - 4: As suggested in the proposed rule, the final rule does not require any bias adjustment when reporting data under this rule. For missing data related comments, see responses to comments under Comment Code 5A12.

5A12 - Testing/Monitoring: CEMS monitor out-of-service versus missing data substitution

Commenters: 17316, 17620, 17655, 17818, 17821, 17877, 17881, 17886, 17904, 18023

1. Agrees that there is no need for missing data substitution.

Comment 1: Several commenters (17655, 17877, 17904) agree with the EPA that there is no need for missing data substitution procedures in this monitoring scheme. According to the commenters, missing data routines are unique to those programs that are market-based rather than performance based in their design. The commenters state that since these monitors are not considered instruments of commerce, normal monitoring downtime provisions should apply.

Comment 2: Commenter 17877 notes that hours when a monitor is out of service should be counted as monitor down time against the percent monitor availability, but substituting data is unnecessary. According to the commenter, maintaining a consistent set of rules to govern monitors that are only used to demonstrate compliance with an emission limit not tied to trading, simplifies the assurance of on-going compliance for both the regulated community and the regulators. The commenter states that eliminating missing data substitution for these monitors will also reduce the file size, complexity, and time required to maintain and report quality assured data.

2. Options for missing data substitution.

Comment 3: Commenter 17620 suggests that sources should be required to infer emissions during monitor downtime at the highest daily rate over the past 90 days during each hour that a monitor is not in service.

Comment 4: Commenter 17818 disagrees with the EPA's proposal to not require data substitution during monitor downtime for Hg, HCl, or PM CEMS. The commenter understands that under the Acid Rain Program the data substitution is essential to properly account for all mass emissions for the pollutant in question, but for the proposed rule, compliance with HAP emissions limitations takes place over a relatively long period of time. The commenter's opinion is that it is appropriate to require data substitution for compliance with long-term emission rate limits to help ensure that a more accurate indication of unit emissions is developed during all periods of unit operation in order to assess the unit's compliance with the applicable emissions limitation. The commenter also notes that a requirement for data substitution will also help encourage the owner/operator to maintain the related CEMS in a high state of accuracy and availability.

Comment 5: Several commenters (17316, 17821, 17881) state that there are conditions other than those listed in section 63.10020(b) that are legitimate reasons for monitoring system data loss and should also be excluded from downtime reporting. The commenters state that these conditions include: planned and unplanned preventive maintenance, corrective action maintenance, diagnostic checks, linearity tests, system integrity checks, cylinder gas audits, QA/QC, system purges, installation of system upgrades, etc. The commenters request that the EPA revise section 63.10020 to reflect that these conditions are not deviations of monitoring requirements.

Comment 6: Commenter 17316 states that traditionally CEMS regulations have been performance based, and this approach has worked well. The commenter states that if the EPA believes monitoring system data loss to be a significant issue then the rule might establish a minimum data recovery threshold, such as 95 percent data availability per quarter, exclusive of calibrations, preventive maintenance and QA testing, as is done in many permits.

Comment 7: Commenter 18023 states that a penalty should not be associated with Hg system availability or monitor downtime. The commenter states that this is because: (1) Hg monitor repairs take much longer to recover and settle once the system is returned to service than current CEMS analyzers for NO_X and SO_2, (2) QA/QC activities take longer to perform, especially with the required calibrator checks, and (3) the sorbent trap versus continuous monitor issue is almost an apples to oranges argument regarding availability with missing days/weeks for sorbent traps versus missing hours for monitors. According to the commenter, section 6.1.3 will only increase the amount of monitor downtime; total availability should be calculated and recorded for tracking purposes but penalties should not be associated with them, especially with the limited experience performing QA/QC with these devices.

Comment 8: Commenter 18023 states that under section 6.1.3 Data Reduction and Calculations, the rule should allow the use of valid Part 75 substituted data for these parameters since those substituted values are acceptable to the EPA for other emission monitoring programs.

Comment 9: Commenter 17886 states that section 63.10020(c), should exclude preventative maintenance and corrective action maintenance activities in what should be considered a deviation of the monitoring requirement.

Response to Comments 1 - 9: We have not included any specific minimum data availability requirement for CEMS or other monitoring in this final rule nor do we provide a specific tool for data substitution. We believe that there are other provisions in the final rule to provide incentives to conduct monitoring in a manner consistent with good air pollution control practices and to provide data sufficient to demonstrate compliance with a relatively long-term emissions rate limit (e.g., lb/MMBtu or lb/MWh). We agree that data quality certainty associated with any calculated value decreases with the collection of fewer data such as would occur with extended periods of monitoring system downtime. Even so, we believe also that it is necessary and critical to compliance with the regulation that a source uses all measured data collected during an averaging period to assess compliance regardless of any periods of missing data. Sources should not disqualify any data otherwise meeting required data quality requirements simply because there were data missing for other hours or days of the averaging period.

Instead of a minimum data availability threshold that would invalidate data collected for some averaging periods because one did not collect data for at least "x" percent of an averaging time, the final rule requires that a source report as deviations to the rule failure to collect data during required periods and that are not covered by exceptions allowed in the final rule.

On the issue of applying a data substitution procedure to represent actual emissions or pollution control performance, we believe that defensibility concerns make it incumbent on you to collect and evaluate other information in accordance with 40 CFR section 63.6(f)(3) during periods of monitoring downtime to assure compliance with the applicable emissions limitations and standards.

We believe that enforcement authorities also can and should determine whether a source is meeting any monitoring system operating requirements. Should the source or the enforcement authority be concerned about the representativeness of data such as during periods of missing data, either may consider collecting information through other means (e.g., supplemental emissions testing) to fill data gaps not only because such gaps are deviations from the rule but such gaps can lead to uncertainty about compliance status.

We further believe that the final rule provides sufficient means to ensure CMS performance and ongoing compliance without specifying an arbitrary numerical minimum data availability or data substitution requirement. We believe that specifying that failure to collect required or otherwise excepted data is a deviation from the rule will provide the necessary incentive to collect data sufficient to demonstrate compliance with the limits in the final rule.

5A13 - Testing/Monitoring: Oil monitoring option

Commenters: 17316, 17870

Comment 1: Commenter 17316 observes that section 63.10011 seems to indicate that a unit may not fire any fuel whose Hg, chlorine, fluorine or non-Hg total Metals content is greater than that measured in the fuel combusted during performance testing (unless the unit is equipped with a CEMS), so that HAP content of the fuel combusted during performance testing establishes an upper bound on the HAP fuel content for all subsequent fuel deliveries (until the next performance test), without any consideration of the extent to which performance test emissions were below the applicable MACT standard. The commenter states that this approach to setting fuel based MACT operating limits seems unnecessarily restrictive, and imposes very difficult compliance issues, as the HAP content of fuel oil is not subject to contract specification. The commenter proposes an alternative method to establish a maximum allowed HAP: adjust the HAP content of the fuel oil combusted during performance testing to account for the amount by which measured stack HAP emissions fell below the applicable HAP standard. The commenter states that this same approach could be applied to all fuel oil HAP constituents because: (a) the only source of Hg, chlorine, fluorine, and non-Hg metals is the fuel itself, and (b) because it is reasonable to assume that the fraction of HAP in the fuel emitted as stack emissions should be relatively constant, so long as any add-on controls are operating properly, it would seem reasonable and appropriate to proportion up the HAP content of the fuel combusted during performance testing, by the ratio of HAP emission standard to the measured HAP emissions, in order to determine an appropriate operating limits for each HAP constituent in fuel oil. According to the commenter, this approach protects the standard, but avoids placing an unmanageable and unfair compliance (fuel) restriction on the site.

Response to Comment 1: The comment is moot because the rule no longer requires fuel analysis or operating limits based on non-Hg metals content of fuel. The only fuel monitoring provision in the final rule is an option for liquid fuel units to use fuel moisture monitoring. If you combust liquid fuels and you wish to demonstrate ongoing compliance with HCl and HF emissions limits by measuring fuel moisture content of fuel in place of quarterly stack testing.

Comment 2: Commenter 17316 states that in regard to requirements that if a source demonstrates compliance with HAP limits "based on fuel analysis, you must conduct monthly fuel analysis for each type of fuel burned." The commenter notes that oil is a homogeneous fuel that is relatively consistent (from shipment to shipment), and therefore such frequent fuel sampling and analysis for oil-fired EGUs is not warranted.

Comment 3: Commenter 17316 states that the monthly fuel analysis required in section 63.10006(s) contradicts the discussion of this topic in the preamble (FR page 25053 column1) which specifies that (after the initial compliance demonstration by fuel analysis)], the EPA "is proposing a source be required to recalculate the fuel pollutant content only if it burns a new fuel type or fuel mixture." The commenter is concerned that this requirement is unjustified for sites that receive oil deliveries less frequently than monthly. The commenter proposes that fuel sampling for oil fired units only need be conducted in months that additions are made to the oil storage tank serving the boiler, but this sampling should be conducted subsequent to all deliveries in the month.

Response to Comments 2 - 3: Much of these comments are moot because the rule no longer requires fuel sampling; however, the agency agrees that fuel moisture sampling (if that option is selected by a source) need only occur on delivery of a new shipment of fuel oil.

Comment 4: Commenter 17870 asks for clarification of the rule allowing fuel analyses to demonstrate initial and continuous compliance with applicable emission limitations, as an alternative to performance stack testing and continuous compliance. The commenter states that in the rule, owners/ operators of all affected liquid oil-fired units may perform fuel analyses to demonstrate initial and continuous compliance, but in the preamble (FR page 25031) limited-use liquid oil combustion units are allowed "to demonstrate compliance with the Hg emission limit, the HAP metals, or the HCl and HF emissions limits separately or in combination based on fuel analysis rather than performance stack testing, upon request by you and approval by the Administrator." The commenter asks for clarification on whether this applies to limited-use or all liquid oil-fired units.

Response to Comment 4: In large part, this comment is moot, as the rule no longer allows metals or hydrogen halide sampling of fuel oil. As mentioned elsewhere, in reviewing comments on monitoring frequency and burden, the agency dropped fuel analyses and operating limits based on those fuel analyses, reduced stack testing frequency to quarterly for both units with and without controls, and developed a stack testing exemption in quarters with limited operating hours. In particular, units that exhibit limited use – less than seven days of boiler operation per quarter – are exempt from testing for that quarter; however, each unit must perform a stack test at least annually. The limited use provision gives relief to sources while maintaining expected emissions performance. In addition, if an EGU has an oil-fired capacity factor of less than 8 percent evaluated on a 24 month block average, then the only standard that applies is the performance tune-up requirement (see Comment Code 4D02 of this document). Should an owner or operator of a liquid oil-fired unit choose not to conduct stack testing to demonstrate compliance, the rule allows an owner or operator to choose continuous monitoring as an alternative means of demonstrating compliance. In addition, the rule will still contain HCl and HF emissions limits for units that combust fuel oil and use of emissions testing or of CEMS to demonstrate compliance with those emissions limits, but the rule will allow moisture content sampling of the fuel oil as an alternative means of demonstrating compliance for units that have fuel moisture content no greater than 1.0 percent. The rule no longer requires establishment of operating parameters for control devices for these pollutants. See more discussion of the EPA's responses to operating parameter monitoring under Comment Code 5A06 in this document.

5A14 - Testing/Monitoring: Other

Commenters: 16513, 16849, 17316, 17402, 17620, 17622, 17626, 17627, 17637, 17638, 17655, 17681, 17690, 17696, 17697, 17704, 17705, 17715, 17716, 17718, 17724, 17725, 17729, 17730, 17731, 17737, 17739, 17740, 17754, 17758, 17760, 17761, 17767, 17775, 17781, 17796, 17800, 17803, 17804, 17805, 17807, 17808, 17812, 17813, 17816, 17818, 17820, 17821, 17838, 17855, 17856, 17867, 17868, 17870, 17873, 17880, 17881, 17886, 17902, 17909, 17925, 17927, 17928, 18014, 18024, 18025, 18031, 18034, 18039, 18428, 18444, 18477, 18487, 18498, 18502, 18539, 18963, 19033, 19114, 19120, 19121, 19536/19537/19538, 18023

1. Commenters concerned about the proposed frequency of performance tests.

Comment 1: Numerous commenters (17402, 17627, 17638, 17681, 17696, 17704, 17716, 17718, 17725, 17737, 17740, 17758, 17760, 17775, 17796, 17800, 17803, 17804, 17807, 17816, 17820, 17821, 17838, 17856, 17867, 17870, 17881, 17902, 17909, 17925, 18014, 18025, 18031, 18428, 18444, 18477, 18963, 19033, 19114, 19120) believe that the proposed frequency of performance testing under section 63.10006 is excessive or overly burdensome.

Comment 2: Commenters 16513 and17804 state that the rule would significantly increase the workload of state agencies by as much as 50 percent as a result of observing emission tests and/or reviewing emission test protocols, and updating AFS. Commenters recommend revising the testing to quarterly or biannually. .

Comment 3: Several commenters (17402, 17627, 17704, 17716, 17718, 17760) state that the EPA should allow facilities to comply with the performance testing requirements on an annual basis similar to their current permit requirements. Commenter 17402 believes that less frequent stack testing coupled with more frequent fuel sampling can ensure continuous compliance because data in the docket indicate that over the long term, emissions are fairly consistent despite potential variability in fuels and operations. Commenter 17402 believes that annual Method 29 stack testing combined with existing permit requirements (to properly operate air pollution control equipment at all times) combined with monthly fuel samples and calculations (consistent with proposed section 63.10011) compose a viable means for ensuring continuous compliance. Commenters (17402, 17718) believe this suggested combination is preferable to the logistical and cost concerns implicit in monthly or bi-monthly testing requirements, and the commenters cite the limited availability of test crews, coordination with system dispatch, scheduled boiler maintenance, and winter storms as constraints that make the proposed monthly and bi-monthly testing frequencies infeasible. Commenter 17402 provides an analysis of stack test data submitted by EGU operators under the ICR to support his position that emission rates are stable.

Comment 4: Commenter17760 indicates that many dual-fuel (oil or gas) units maintain permits to burn fuel oil for periods of high electricity demand when natural gas may not be available (due to residential heating demand) and states that recent natural gas prices make fuel is concerned that the monthly or bi-monthly testing requirements will force dual. The commenter states that first, the proposed frequency of testing will impose a significant cost burden on plant operators. For example, all of commenter 17803's units are gas capable and, with the current difference in oil and gas prices, oil is consumed only during periods of gas unavailability or as required by the New York Independent System Operator to ensure reliability during periods of high electric demand. According to the commenter, monthly testing would result in significant economic burdens. For example, commenter 17803's cost of the uneconomic oil consumed during the 2010 ICR testing last year was approximately $2-3 million. Second, states the commenter, inflexible testing schedules may induce units to run solely for testing purposes, leading to increased emissions. According to the commenter, any oil-fired units are operated as peakers or cycling units, and may spend a significant portion of the year off-line and the proposed testing requirements would require these units to run even if there were no demand for additional power. Commenter 17316 adds that for dual fuel (oil/gas) units, the proposed testing regimen is even more environmentally counter- productive because these units tend to operate on natural gas during the ozone season, but proposed section 63.10007(c) would require the firing of oil during ozone season.

Comment 5: Several commenters (17316, 17627, 17716, 17718, 17725, 17760) state that the proposed performance testing requirements for sources without CEMS are cumbersome and expensive for units with low annual capacity factors (e.g., oil-fired units) because frequent performance testing could require operation of such units during periods of low electricity demand when such units normally do not operate. Commenters (17316, 17760) state that in some cases the proposed testing frequency for oil-fired units with low annual capacity factors will result in an increase in annual HAP emissions that could exceed any reduction in hourly emission rates achieved by the rule. Commenter 17760 adds that if the EPA does not agree with annual testing of oil-fired units with low annual capacity factors, then the testing frequency should be a function of “fuel operating” hours.

Comment 6: Several commenters (17627, 17718, 19114) believe that the EPA’s assertion that most units will choose to install CEMS rather than the burdensome stack testing option may be faulty because HCl CEMS technology is not yet available, PM CEMS are still quite unproven, and other CEMS systems may be incapable of measuring emissions as low as the EPA has proposed. Commenter 19114 further states that for low capacity units they have determined that they could not complete such testing at all of its units within a 2-month period due to lack of test crews, unit scheduling, scheduled maintenance, and other considerations. According to the commenter, the EPA should consider the frequency and types of monitoring appropriate for various subcategories, including an exemption for low capacity factor and LEE units.

Comment 7: Several commenters (17638, 17681, 17725, 17740, 17758) state that the proposed monthly or bi-monthly testing frequency is excessive, unnecessary, and cost prohibitive. Commenters (17638, 17681, 17758) note that the EPA established the limits based on single tests from multiple units, and conclude that there is no basis for the proposed frequency.

Comment 8: Commenter 18477 states that to conduct source testing, commenter must establish a schedule that maximizes the amount of work done by the vendor in the minimal amount of time, in order to manage the exorbitant cost of importing such expertise and equipment. The commenter states that any upset that occurs during the source testing schedule, a common phenomenon when testing multiple units within a relatively short time frame, further strains commenter’s generation resources. Commenter states the current proposed rule, assuming installation of control devices for non-Hg metals on all 14 of commenter’s units, testing each of 14 steam units every other month equates to 84 source tests annually. If the four units commenter has identified for potential retirement were not equipped with such devices, 108 source tests would be required under the proposed rule. In either case, states the commenter, the proposed rule’s non-Hg metals source testing regime would be a severe burden to our already overburdened ratepayers. The commenter notes that the cost of source testing in significantly higher than in the continental U.S. and that the commenter paid a 20 percent premium to perform the ICR testing.

Comment 9: Several commenters (17760, 17881, 18477) note that annual testing would be consistent with the industrial boiler MACT (DDDDD), stationary combustion turbine MACT (YYYY), and the RICE MACT (ZZZZ) that provides semi-annual to annual testing.

Comment 10: Commenters 17870 and 17881 state that the proposed testing frequency is impractical to conduct especially in the northern climates where temperatures in many months (about 5) of the year are too cold. According to the commenters, severe weather events can postpone stack access for safety reasons (ice, lightening), thus reducing the margin of maintaining such a rigorous test schedule. The commenters state that the process of submitting test notifications, conducting the test, and then reporting is a never ending paperwork loop. Commenter 17881 suggests that annual testing is more reasonable for units without CEMS but with controls and operating limits and semi-annually for units with CEMS. Commenter 17870 suggests the all stack testing requirements governing coal-fired EGUs should be no more frequently than quarterly under standard operation (i.e., unless boiler operations or characteristics are substantially altered, in which case initial testing should be repeated). According to the commenter, quarterly stack testing in combination with parameter monitoring (discussed below) should be enough to ensure that a unit is operating within the required limits, and quarterly testing would capture seasonal variations in operation while not unnecessarily repeating testing of the same conditions.

Comment 11: Commenter 18502 recommends that the EPA reduce the compliance testing requirements based on the relatively small size and emissions and remoteness of non-continental EGUs burning liquid oil.

Response to Comments 1 - 11: In response to these comments, the final rule includes a number of changes from the proposed rule that will reduce the overall testing required under the final rule. First, the final rule establishes a separate subcategory for an EGU with an annual oil-fired capacity factor of less than 8 percent. These units are subject only to the performance tune-up work practice standard in the final rule. Second, the optional periodic testing requirements have been made consistent between controlled and uncontrolled sources, with a reduced frequency of quarterly performance testing. In addition, the final rule has removed all requirements for duplicative testing of a HAP and surrogate standard (such as filterable PM and HAP metals).

Comment 12: Commenter 17856 questions the need for such frequent stack testing for units with CEMS because of the extensive operational and parametric monitoring.

Response to Comment 12: The final rule has been amended to not require additional performance testing if complying with Hg, HCl or SO_2 CEMs. For sources electing to use PM CPMS, the performance testing frequency has been reduced to annual testing.

Comment 13: Multiple commenters (17638, 17681, 17690, 17716, 17725, 155, 156, 17758, 17760, 17803, 17820, 17870, 17902, 17909, 18014, 18025, 18428, 18498) believe that the testing frequency for units opting to comply with the non-Hg HAP metal or HCl emission limits should be once every four unit operating quarters (not calendar quarters), but no less frequently than once every eight calendar quarters following the required frequency for RATA's at 40 CFR Part 75, Appendix B, section 2.3.1.1 and using the definition for "operating quarter" under part 72.2 (i.e., 168 or more unit operating hours). Commenters 17820 and 17881 state that testing guidelines under section 63.10006(n) should use the operating days and quarters approach of Part 75.

Response to Comment 13: As previously explained, the optional periodic testing requirements have been made consistent between controlled and uncontrolled sources, with a reduced frequency of quarterly performance testing. In addition, the final rule has removed all requirements for duplicative testing of a HAP and a separate alternate equivalent standard (such as filterable PM and HAP metals).

Comment 14: Multiple commenters (17716, 17725, 155, 17820, 18498, 17775, 17800) request that the testing provisions in the final rule incorporate a grace period similar to the Part 75 provisions. According to the commenters, such a grace period allows a source time to complete testing after coming back online and would benefit sources and the EPA by eliminating the need for submission of source specific petitions to seek minor extensions of testing deadlines.

Response to Comment 14: The final rule allows for testing grace periods consistent with those allowed in part 75.

Comment 15: Several commenters (17716, 17821, 17881) state that the specific testing deadlines that are provided in section 63.10006(n) will be overly burdensome not only for limited operation units, but also for units in extended planned or unplanned maintenance outages. The commenters note that section 63.10006(n) does provide windows for testing, they may be inadequate for planned unit maintenance outages. Commenter 17821 suggests establishing guidelines and allow sources to work with state and local permitting agencies to schedule tests.

Comment 16: Commenter 18025 recommends that a unit operating hour be defined as a clock hour during which a unit combusts any regulated fuel, either for part of the hour or for the entire hour. Commenter is recommending that this definition apply specifically to the regulated fuels under the Utility Toxics Rule (e.g., coal and liquid oil). By requiring a minimum level of operation to trigger stack testing requirements, states the commenter, this approach would ensure that no unit is run simply for the sake of testing

Response to Comments 15 - 16: As previously explained, the optional periodic testing requirements have been made consistent between controlled and uncontrolled sources, with a reduced frequency of quarterly performance testing. In addition, the final rule has removed all requirements for duplicative testing of a HAP and a surrogate standard (such as filterable PM and HAP metals).

Comment 17: Commenter 17681 recommends the testing schedule, instead of annual testing on a 13-month timescale, be revised to "or every other federal fiscal year" or something along those lines so that facilities may coordinate testing with their state required permits for consistency.

Comment 18: Commenter 19033 recommends that the HCl sampling frequency be reduced from every other month to quarterly in the second year, and biannual the third year if HCl emissions are measured to be non-detectable for all tests conducted. Accordingly, the commenter recommends that section 63.10006(j) be amended, as follows: (j) For solid oil-derived fuel- and coal-fired EGUs without HCI CEMS but with HCl emissions control devices, you must conduct all applicable performance tests for HCl emissions according to Table 5 and section 63.10007 at least every other month *during the first calendar year after the standard becomes applicable. Provided that HCI emissions are measured to be non-detectable, the HCI emissions testing frequency may be reduced to quarterly during the second year and bi-annual the third year.*

Commenter 17722 states that for language in section 63.10006(j), the EPA should add an exception for EGUs monitoring continuously by SO_2 CEMS, as the bi-monthly performance tests are not required for continuously monitored surrogates.

Comment 19: Commenter 17821 states the proposed testing frequency constrains a company's ability to follow customer demand and increases a company's cost to operate its generation resources. According to the commenter, existing tests such as periodic RATAs are less frequent, of shorter duration, and/or allow much more operational flexibility, and the proposed Utility MACT tests by comparison are far more frequent, of longer duration, and demand more operational restrictions requiring operators to focus on making their generating units available for testing conditions to the detriment of the primary function of generating electricity. The commenter states that the proposed rule is too prescriptive in telling sources how they are to operate their facilities. According to the commenter the EPA fails to recognize that requiring a single unit to satisfy testing conditions also constrains other units in the system.

Comment 20: Commenter 17796 questions the proposed frequency of stack tests in section 63.10006(d). As an alternative to the requirement for monthly or bimonthly stack tests (depending on the use of control devices), the commenter recommends that once the initial performance test is conducted for PM (filterable and condensable) and non-HAP metals, and fuel sampling procedures and operating parameters are established, compliance will be assured by the use of such fuel sampling and operating data combined with less frequent (semiannual) stack testing.

Comment 21: Commenter 17925 recommends that continuous compliance source testing should be required no more frequent than annually. The commenter states that the EPA has had a past history of requiring annual source testing at coal-fired units where continuous monitors for certain emission species either didn't exist or couldn't be applied at the source; for instance, at some coal fired units in the past, opacity monitors couldn't be applied on wet plumes after scrubbers. As a result, states the commenter, the EPA required annual total particulate testing by Method 5 in lieu of requiring the operator to make an opacity monitor perform on the wet plume. The commenter requests the EPA to apply the same sound judgment now with respect to frequency of source testing for demonstrating continuous compliance with metals emissions and HCl.

Comment 22: Commenter 17316 suggests that performance testing for oil-fired units should be conducted every 3 years rather than the schedule proposed in section 63.10006(f),(g),(l) and (m) because the proposed schedule is unjustified and a very substantial economic burden for smaller utilities. Commenters (17316, 17725, 17760) indicate that the total expenditures for such a test program include the direct monthly costs of contracted testing services and the significant costs of operating oil-fired units strictly for monthly tests when other more economical generating units are available to meet the demand for electricity or requiring dual fired units to burn fuel oil for testing purposes when natural gas prices are lower than residual fuel oil. According to commenter 17725, performance testing of a unit without metals or acid gas controls requires a minimum of 4 full load hours per month; an additional 2 hours at full load for boiler stabilization; potential additional runs if the test crew has problems; and time for calibrations between test runs. The commenter estimates such a unit would operate for 72 hours per year just for testing, not including the time to start-up the unit, ramp the unit to full load and then ramp down the unit. Commenter 17725 states that review of published data for 2008, 2009, and 2010 shows at least 34 residual oil-fired units whose 3-year annual capacity factors are 5 percent or less.

Comment 23: Several commenters (17316, 17870, 18428) state that oil is a homogeneous and reasonably consistent fuel, so that variations in the metals, chlorine, and fluorine contents should not be significant and therefore monthly or bimonthly testing is not warranted. Commenter 17870 states that fuel analysis on each shipment of oil should be sufficient to demonstrate compliance. Commenter 18428 states that in the preamble, the EPA states that additional performance tests for Hg are conducted "at least annually." However, there is no reference to this annual testing in the proposed rule. Given the extremely low level of Hg in oil, states the commenter, any requirement or reference to annual testing for Hg emissions from oil-fired units is unnecessary and should be removed

Comment 24: Commenter17704 appreciates the proposal's inclusion of an alternative to the use of PM CEMS for monitoring non-Hg metals emissions, but the commenter states that the bi-monthly stack testing alternative is not practical because the effected source operator does not have resident stack testing crews, and the scheduling of tests with contract testing crews and the scheduling of testing loads with the grid reliability control center would be difficult to do every two months. Commenter 17704 states that the amount of metals in the PRB coal utilized at the effected source does not change significantly and annual testing should be sufficient for monitoring the non-Hg metals.

Comment 25: Several commenters (17716, 17725, 17758, 18014) state that the proposed frequency of performance testing is not consistent with the expected variability in emissions because units without add-on control systems are required to complete stack test less frequently than units with add-on control systems, but for units without add-on control systems, the emissions of HCl, HF, and non-Hg metals are most closely tied to fuel characteristics. These commenters and commenter 17402 suggest that in lieu of the proposed monthly or bi-monthly frequency, periodic fuel analyses should be used to determine if a significant change has occurred since the annual performance test. Commenter 17402 provides suggested revisions to proposed section 63.10006 and section 63.10021 outlining a methodology for using monthly fuel analyses and performance tests conducted every 4 unit operating quarters; the suggested methodology includes criteria for using monthly fuel samples to determine when higher frequency stack testing is required. Commenters (17716, 17725) cite statements in the preamble to the proposal indicating that for liquid oil-fired units, no correlation was found between non-Hg metallic HAP emissions and PM emissions or the operation of PM control devices. These commenters conclude that the emissions of HCl, HF, and non-Hg metals are most closely tied to fuel characteristics and that periodic assessment of fuel characteristics should be used to determine whether additional emission testing is needed. This commenter also believes that the source's expected removal efficiency should also be taken into consideration to minimize unnecessary testing.

Comment 26: Commenter 17718 encourages the EPA to maximize the efficiency of monitoring and reporting requirements and to avoid redundancy. This commenter states that the data gathering requirements in the proposal are extremely difficult due to the lack of approved test methods, data variability, and short deadlines for testing. The commenter suggests that the EPA should extend the testing frequencies to at least a quarterly basis to allow more substantial analysis of gathered data and to reduce potential burdens resulting from more frequent laboratory analyses and test report submittals.

Comment 27: Commenter 17737 states that a monthly testing frequency is unmanageable for units that do not have SO_2 control technology or HCl CEMS, and the commenter states that proposal provide no explanation for this unprecedented frequency. According to the commenter all plausible operating scenarios that could utilize the compliance option for sources without SO_2 controls require use of fuel with very low chlorine content. In such cases, states the commenter, fuel analyses provide assurance of compliance at a fraction of the cost. This commenter believes the final rule should allow operators to maintain records of the type of fuel being burned and to perform monthly fuel analyses to demonstrate that the fuel chlorine content is within acceptable limits.

Comment 28: Commenter 17718 is concerned that the monthly or bi-monthly performance testing option may be incompatible with timely submission of test reports under proposed section 63.10006(t) because historically, testing firms and labs have not handled the high volumes of work implicit in this compliance option.

Comment 29: Commenter 17821 states that the proposed initial testing schedule requiring tests within 30-operating days of the startup of new controls is too tight. According to the commenter, few installation projects will meet their construction deadlines and will force initial testing into very compressed schedules.

Comment 30: Commenter 17807 states that the proposed testing frequency is not practicable and not justified. The commenter suggests annual stack testing and a CAM plan instead of bimonthly testing.

Comment 31: Commenter 17880 supports the requiring of liquid oil-fired units to conduct additional performance testing for Hg on an annual basis; conduct additional performance tests for HAP metals and acid gasses every 2 months for units that have emissions controls, and monthly for units that do not.

Comment 32: Commenter 17867 notes that several MACTs allow for less frequent testing given consecutive passing results as follows:

- 40 CFR 63 subpart DDDD (Boiler MACT) section 63.7515 – testing frequency is annual until compliance is demonstrated for 3 consecutive years, then frequency is relaxed to every 3 years.
- 40 CFR 60 subpart KKKK (Combustion Turbine NSPS) section 60.4340 – testing frequency is annual unless emission are less than 75 percent of the standard, then frequency is relaxed to every 2 years.
- 40 CFR 60 subpart DDDD (CISWI MACT) section 60.2720 – testing frequency is annual unless emissions are less than the standard or 75 percent less than the standard (depending on the pollutant), then frequency is relaxed to every 3 years.
- 40 CFR 60 subpart CCCC (CISWI MACT) section 60.2155 – testing frequency is annual unless emissions are less than the standard or 75 percent less than the standard (depending on the pollutant), then frequency is relaxed to every 3 years

According to the commenter, metals and HCI stack testing every other month is unnecessarily burdensome. Commenter suggests the frequency should be extended to every 6 months if two consecutive tests demonstrate compliance with the standard. The commenter states that if two consecutive semi-annual tests demonstrate compliance, frequency should be extended to annual testing, and frequency should be increased if a subsequent performance test indicates the emission standard is not being met or if more than 50 percent of the fuel has been switched to a different type of coal (e.g., subbituminous/bituminous, supply from different basin).

Comment 33: Several commenters (17681, 17870, 18034, 18428) question whether, because of the prescriptive testing deadlines, if a unit is not operated within the timeframes specified will the unit be required to start-up simply for testing purposes.

Response to Comments 17 - 33: See response to Comments 15 and 16.

Comment 34: Commenters (17800, 17886) state the start date of the performance tests under section 63.10005 should be flexible to allow for monitor certification to be completed, operating conditions to be established, and shakedown of control devices to be performed.

Response to Comment 34: The Agency finds that the rule's start dates of the performance tests are flexible and will allow for monitor certification and similar activities to occur.

General Response to Comments 1 - 34: For stack test frequency, the EPA has modified the final rule to require quarterly testing if used to demonstrate continuous compliance and included an exemption for testing in quarters with low utilization (<168 operating hours). In addition, EPA agrees that testing should be required only for the emission limit that the source is complying with, and thus the final rule does not require testing of both the HAP and a separate surrogate standard (such as filterable PM for HAP metals).

2. HCl testing section 63.10006(j).

Comment 35: Commenter 17821 requests that the EPA clarify this section of the rule to indicate whether sources choosing to use the alternate method of compliance with the HCl limitations defined in Table 5 (use of a CEMS to measure SO_2 emissions and limiting the emissions rate to less than 0.2 lb/MMBTU) are required to conduct HCl performance testing every 2 months. With section 63.10000(c)(1) defining a SO_2 CEMS as an alternative to an HCl CEMS, the commenter recommends that the EPA should not require sources using this alternative to conduct performance testing for HCl every 2 months. Rather, the commenter recommends that the frequency of performance testing for HCl, when utilizing the alternative method of compliance with a sSO_2 monitor and a reduced SO_2 emission rate, should be the same as for those sources choosing to utilize an HCl CEMS.

Response to Comment 35: The final rule has removed all requirements for duplicative testing of a HAP and a surrogate standard (such as HCl and SO_2). Facilities complying with a surrogate standard do not have to perform periodic testing for the corresponding HAP.

Comment 36: Commenter 17696 states that for coal-fired EGUs without an HCl emission control device, the key factor in determining maximum potential HCl emissions is the maximum coal chlorine input. For coal-fired EGUs with HCl control devices, states the commenter, a second key factor in determining maximum potential HCl emissions is the control device's operating parameters, which under the proposed rule also must be continuously monitored to assure compliance, and as long as there is no change in coal type or coal mixture (or change in emission control device operations), there is no need to perform HCl stack testing every month or every other month - simply keeping the coal chlorine input below maximum allowable levels (and, as applicable, keeping the control device's operating parameters within allowed ranges) is sufficient to ensure continuous compliance.

Response to Comment 36: The final rule has removed most of the options for fuel sampling and analysis as a compliance option. Sources choosing to not use HCl CEMS for uncontrolled sources must perform periodic performance testing. However, if you combust liquid fuels and you wish to demonstrate ongoing compliance with HCl and HF emissions limits by measuring fuel moisture content of each shipment of fuel in place of quarterly stack testing, you may develop a unit-specific approach utilizing fuel moisture content measurements, collect data necessary to support your approach, and petition the Administrator under 40 CFR section 63.7(f) for an alternative compliance testing approach.

Comment 37: Commenter 17725 requests that the final rule clarify that testing for HCl is not required if the site operator has instituted the alternate compliance method of percent water in fuel deliveries.

Response to Comment 37: The final rule has removed most of the options for fuel sampling and analysis as a compliance option. However, if you combust liquid fuels and you wish to demonstrate ongoing compliance with HCl and HF emissions limits by measuring fuel moisture content of each shipment of fuel in place of quarterly stack testing, you may develop a unit-specific approach utilizing fuel moisture content measurements, collect data necessary to support your approach, and petition the Administrator under 40 CFR section 63.7(f) for an alternative compliance testing approach.

3. Reduced frequency criteria.

Comment 38: Commenter 17821 states that the reduced stack test provisions at section 63.10006(c) are too burdensome. Commenter believes that the threshold for extended testing frequency should be that the unit demonstrates 80% - 90% of the standard because the EPA is also requiring worst-case fuel conditions, full load, and other requirements intended to provide the absolute worst case test conditions for what are relatively short-term periods. In the real operating world, states the commenter, a unit will simply not continue to operate in worst-case conditions, rather, the average fuel concentration will be less, load will decrease, etc.

Comment 39: Commenter 17821 asserts that the requirement that a source must demonstrate compliance for 3 years is far too burdensome. The commenter notes that the EPA states "If a performance test shows emissions in excess of 50 percent of the emission limit, you must conduct performance tests at the appropriate frequency given in section (c) through (m) of this paragraph for that pollutant until all performance tests over a consecutive 3-year period show compliance"; in other words for the parameters where the EPA is requiring sources to test every month, or every other month, sources will have to conduct 18-36 individual test before they can qualify for reduced frequency. According to the commenter, this imposes a burden on the source and the permitting agency and it appears the EPA is attempting to ratchet the emission limit down by half.

The commenter recommends that the EPA make two important changes in the frequency of its required reference method testing: first, the EPA should require reference method testing that is no more often than quarterly for any pollutant and equipment configuration, and second, once a unit has successfully demonstrated emission levels that are at no more than 80% to 90% of an applicable standard for 2 consecutive quarters, the testing frequency be reduced to semi-annually. The commenter states that then once a source has demonstrated compliance with the applicable standard for two additional tests, the frequency would be further reduced to annually. Finally, states the commenter, the EPA must address the issue of how a limit of detection is handled in the context of reduced testing frequency.

Response to Comments 38 - 39: The final rule has been amended to quarterly testing for all pollutant and equipment configurations. The EPA disagrees with the 80 to 90% criteria for reduced testing suggestion due to the option for use of CEMS instead of periodic testing and the removal of prescriptive parameter and fuel monitoring.

Comment 40: Commenters 1775 and 17800 state that the EPA should remove the 50% criterion for reduced testing as the EPA provided no reason for this restriction. According to the commenters, the EPA has not provided any data suggesting that any source could achieve 50% of the proposed limits some of which are at or near the detection limits.

Response to Comment 40: The EPA disagrees with the commenter and will retain the 50% criteria. The emission standards in the final rule are at least three times the RDL, so any source below a typical detection limit would meet these criteria. In addition, the quarterly periodic performance testing is an option for sources choosing to not install CEMS or PM CPMS.

Comment 41: Commenters 17881 and 19033 state that section 63.10006(q) is unclear. According to the commenters, it seems the intent is to require that the more frequent testing frequencies must be met if a performance test shows emissions greater than 50% of an allowable limit, yet the increased testing frequency is required until all performance tests over a consecutive 3-year period show compliance.

Response to Comment 41: The reduced frequency option is only available to sources that meet the 50% criteria during the 3 years of periodic testing.

Comment 42: Commenter 17881 states that section 63.10006(o) allows for reduced frequency of testing from annual or more frequent to once every 3 years (i.e., no more than 37 months) after the previous performance test. The commenter states that in order to qualify for this reduced testing frequency, 3 consecutive years of testing must show that emissions are at or below 50% of the applicable emission limit. In light of the very stringent emission limits, the commenter questions why results have to be less than 50% of threshold. For comparison, states the commenter, in the Boiler MACT, to qualify for reduced frequency, units had to demonstrate emissions at or below 75% of the emission limit. Also, states the commenter, it seems disproportional for units that are testing bi-monthly or monthly to have to conduct 18-36 tests to establish a pattern of compliance versus units testing annually to conduct as little as three discrete tests. According to the commenter, reduced frequency should be based on the number of passing consecutive tests; the RICE MACT utilizes this concept in that after compliance is demonstrated for two consecutive semi-annual tests, the testing frequency can be reduced to annually. The commenter suggests that for non-CEMS units there should be a tiered approach in regards to the number of passing tests based upon the original testing frequency; i.e., six passing tests for bi-monthly tests and 12 passing tests for monthly tests.

Response to Comment 42: In response to comments, the final rule has been amended to reduce the frequency of testing from 1 or 2 months to quarterly testing. Also, the quarterly periodic performance testing is an option for sources not choosing to install and operate CEMS.

Comment 43: Several commenters (19536, 19537, 19538) assert that the frequency of testing should depend upon the variability of each parameter. According to the commenter, when a parameter is variable, more frequent monitoring is required to assure continuous compliance; as a rule, where a parameter fluctuates significantly over a period of time shorter than the specified monitoring interval, the monitoring cannot assure continuous compliance. According to the commenter the proposed limits are heavily premised upon the claim that the regulated emissions are very highly variable and the EPA uses this justification in establishing extraordinarily aggressive statistical adjustments. The commenter states that the EPA's calculations predict emissions from existing sources which range from 2 to 56 times greater than the average data yielded from a test. For new sources, states the commenter, the EPA's calculations predict emissions from 2 to 6 times greater than the average, and according to the EPA's beyond-the-floor analysis (or lack thereof) there are no operational methods available to reduce that variability. Given the unavoidable variation, states the commenter, continuous compliance cannot be determined using the periodic testing proposed in the rule. According to the commenter, if emissions vary by a factor of 2 to 50 (or more), and there is no method available to reduce that variability, direct measurement of emissions every month (or every other month) with annual to every 5 year re-tests, will not ensure continuous compliance between those tests.

Response to Comment 43: We believe that frequency of testing be tied to source performance and be reduced based on demonstration of continued lower emissions, not on potential emissions variability. The EPA believes the provisions of the LEE exemption provide adequate a level of assurance with compliance for better performing units. For non Hg HAP, the sources must show levels below the threshold for quarterly performance tests over a 3-year period. In addition, any change to the process that would result in an increase in HAP emissions would necessitate another performance test. These sources will also be subject to other rules containing provisions for parameter monitoring as discussed in section 5A05.

Comment 44: Commenter 17718 requests that the final rule include a clarification to the proposed language at section 63.10006(o) regarding the criteria for reducing the frequency of performance testing; the final rule should clarify what constitutes "no change" and what information would be needed to successfully pass these criteria. For example, states the commenter, it is unclear whether the "no change" provision applies to the affected unit and is not inclusive of the entire facility.

Response to Comment 44: "No change" would apply to the affected unit.

4. Comments related to "highest content" of HAP.

Comment 45: Commenters 17731 and 17881 state that the requirement to use worst case coal with the "highest content" of HAP in performance testing is not reasonably possible in part due to natural variability. According to the commenters, there is a very real possibility that even if the worst case coal could be identified, that coal very well may not be available for purchase. The commenters state that the proposed rule also fails to distinguish emissions testing requirements among regulated parameters. According to the commenters, the worst case coal is not likely to be the same relative to each of the regulated parameters under the proposed rules. Thus, according to the commenters, EGUs would have a nigh-impossible task of identifying a suite of worst case coals and procuring each of those in order to conduct the required testing. Commenter 17881 suggests defining a primary fuel and retesting on changes to the primary fuel. According to the commenter this approach was used in the CAMR rule under section 75.81(d)(4)(iv). Commenter further notes that even if an EGU is diligent in trying to determine the maximum HAP input levels based upon expected fuel(s), it is entirely possible that the actual HAP input will increase beyond the levels observed during the initial performance tests/fuel sampling and analysis simply due to fuel variability alone (and not a change in fuel type(s) or blends).

Comment 46: Commenter 17718 states that the proposed regulatory language (40 CFR 63.10007(c)) provides that performance tests must be conducted "while burning the type of fuel or mixture of fuels that has the highest content…" The commenter believes the EPA should clarify whether reference to "type of fuel" simply means that if bituminous coal is typically burned then bituminous coal is to be used during the test. According to the commenter, this section does not appear to require a determination that the highest chlorine (or other constituent) content bituminous coal be used during the test. The commenter also suggests clarification that "special fuels" are not required or expected for the performance test.

Comment 47: Commenter 17781 states that for performance testing under section 63.10007(c) the EPA should specify that fluorine content is only relevant for liquid oil-fired EGUs, as no other category of EGUs are subject to HF emission limits.

Comment 48: Commenter 19121 states that placing testing criteria on multiple fuels is burdensome, and close to impossible to include all fuel sources and blends within any single performance test. Additionally, the commenter utilizes bituminous and subbituminous fuel from multiple sources and fire as a blend. Fuel supply can be seasonal and based upon pricing, availability and access.

Response to Comments 45 - 48: Periodic performance tests must be conducted using the fuel type or blending that would represent the highest HAP loading to the control devices for that period of testing. If the source is unsure which fuel would result in the highest HAP loading, they may perform multiple tests within that test period or opt to use CEMS to ensure continuous compliance with the standard.

5. Testing deadlines.

Comment 49: Commenters 17725 and 18498 state that testing deadlines should be established based on time of the last test with no concern for the minimum amount of time since the last test. The commenters state that there is no value to establishing a minimum amount of time before conducting subsequent tests, and if a source completes the test before the applicable deadline, the future test schedule is simply adjusted based on the completion date of the test.

Response to Comment 49: The final rule will be amended in order to remove the minimum amount time since the last test requirement.

6. Comments regarding performance testing and maximum operating load.

Comment 50: Commenters 17730 and 17886 state that the proposed rule requires that sources conduct performance testing under the maximum normal operating load conditions when combustion is most efficient and emissions will be at their lowest. The commenters state that for EGUs using CEMS the performance test will run for 30 operating days. According to the commenters, it may not be possible for sources to maintain a "maximum" normal operating load for a full 30 operating days. The commenters believe that the EPA should simply require representative operation of the unit during performance testing.

Comment 51: Commenter 17316 states that section 63.10007 indicates that performance testing must be conducted at "maximum normal operating load"; however this term is not defined. Commenter suggests that the rule allow sources to apply the Part 75 Appendix A, section 6.5.2.1 procedure to define three operating load ranges for a unit (low, mid, high), and allow a source to perform testing at any load within the "high" load range. According to the commenter, such an approach allows a source to test at a representative load, but ensures testing is conducted at a high load, and hopefully such an approach would reduce the need to perform multiple stack tests, while still basically satisfying the goal of conducting measurements under worst case conditions. The commenter notes that the preamble to the proposed rule indicates that load has little significant impact on HAP emissions (FR Page 25037).

Comment 52: Commenter 17881 states that specifying that the performance tests be conducted at maximum routine operating load is not appropriate, as the EGU should have the flexibility of conducting the test at whatever load is desired with the understanding that in those cases where compliance is demonstrated through performance testing, the average load observed during the performance tests will be used to set a maximum load restriction for all future operation (at 110 percent of the average load during the tests).

Comment 53: Commenter 18024 recommends that if compliance can be achieved by co-firing natural gas and oil at the same time, then a liquid fuel-only compliance demonstration would not be necessary or appropriate so long as enforceable co-firing operating restrictions were implemented. Commenter states that low load operation should be allowed as compliant operation if the mass emission rate of any HAP is maintained below the equivalent full load HAP emission level calculated as the MACT Floor. The commenter requests that the EPA develop a compliance option that represents normal operation of a facility and eliminate testing in modes of operation that are rarely or never utilized.

Comment 54: Commenter 18444 states that the EPA should require that states set maximum allowable hourly heat inputs for each unit and that testing to determine compliance be conducted at these maximum rates. According to the commenter, this heat input limit is especially important for pollutants which do not have a continuous monitor and are tested infrequently (such as particulate HAP). The commenter notes that the proposed rule language on maintaining heat input within 10 percent of the heat input when compliance testing was done is too much leeway; especially with an ESP. The commenter states that emissions can be about 50 percent higher with a 10 percent fuel gas flow rate increase through an ESP. According to the commenter, air pollution control systems are designed for a maximum flue gas flow rate which is directly related to heat input; ESPs are very sensitive to higher amounts of fuel being burned, and scrubbers are also affected as well. The commenter recommends testing within 5 percent of the maximum allowable hourly heat input.

Comment 55: Commenter 18023 states that not only do individual units see significant variability in steady-state full load stack test results, these measurements are not representative of the variability that a unit may experience on a continuous basis through all modes of operation, including startup, shutdown, and malfunction, as may be measured by a PM CEMS.

Comment 56: Commenter 17881 states that it may not be possible to meet operating limits set at the maximum routine operating load at other reduced loads and therefore the concept of conducting multiple sets of performance tests at different operating loads under section 63.10007(c) is unworkable. The commenter appreciates the EPA's attempt at recognizing that it may not be possible to meet operating limits set at the maximum routine operating load at other reduced loads. For example, the commenter asks the following: if an EGU were to test at 50 percent and 100 percent of rated capacity and establish separate sets of operating limits, which set of operating limits would apply at any given time, and would the operating limits established at 50 percent load apply to all loads ≤ 50 percent capacity, ≤ 75 percent capacity (i.e., the mid-point between to two test conditions) or ≤ 100 percent capacity?

Comment 57: Commenter 17881 suggests that a more realistic approach is to specify that the operating limits only apply during those periods when the EGU is operating within a certain percentage of the average load condition associated with the performance test. The commenter states that this approach would be consistent with that taken by the EPA in 40 CFR 63, subpart ZZZZ – NESHAP for RICE. The preceding rule requires that performance testing be conducted at 100±10 percent of rated load (see Table 1a of subpart ZZZZ), and the operating limits established during testing (i.e., pressure drop for oxidation catalysts) only applies when the unit operates at loads of 100±10 percent (see Tables 1b and 2b of subpart ZZZZ). Thus, states the commenter, this approach avoids the possibility of applying an operating limit established at a specific operating load to loads not evaluated during the concurrent performance test.

Comment 58: Commenter 17881 suggests another potential approach would be to use the performance test and associated operating parameter values as verification of a parameter value or range based upon control equipment vendor recommendations. For example, states the commenter, the vendor recommendation for the pressure drop across a wet PM scrubber may be 35" to 40" water column (w.c.); thus, the operating limit could be set at a minimum pressure drop of 35" w.c., and the performance test could be used to verify that PM emission rates and or non-Hg HAP Metals emission rates at pressure drops at or above the vendor recommendation comply with the applicable emission limits. According to the commenter, this approach is very similar to the approach taken in 40 CFR Part 75, Appendix E, which allows the use of a parametric monitoring approach for NO_X emissions. Essentially, states the commenter, stack testing is conducted to establish a relationship between NO_X lb/MMBtu emission rates and unit load; prior to conducting the stack testing, four parameters indicative of NO_X emissions, along with the vendor recommended values or ranges for these parameters across the expected operating range, are identified. During testing, states the commenter, the actual parameter values must be consistent with the vendor recommended values or ranges, and the EGU must conduct ongoing monitoring of the parameters following emission testing and verify that they remain consistent with the vendor recommend ranges or values. According to the commenter, operating outside the vendor recommended ranges or values results in a requirement to conduct additional testing.

Comment 59: Commenter 17718 states that under section 63.10007(f) the EPA should clarify whether it will specify when and how performance testing is to be completed, beyond what is already proposed in other sections of the regulatory language. The commenter states that other sections of the proposed regulatory language specify when, how and under what conditions the performance testing is to be conducted, and therefore, the proposed section 63.10007(f) appears unnecessary and should be removed.

Comment 60: Commenter 19121 states that the proposed rule places limits on changing operating modes and equipment in configurations different than those configurations used during a performance test and that this would require sources to operate in every conceivable configuration during performance testing. The commenter states that this could mean that performance testing could literally take months to perform. As an example, states the commenter, the commenter enjoys high availability due to redundancy of systems. For instance, states the commenter, the scrubber for each unit consists of six modules; four modules are required for full load, two or three modules for start-up and low loads. The commenter states that completing a performance test so that all operating configurations would be considered acceptable under the proposed rule would necessitate numerous individual test arrangements, and this would also be true for every burner configuration and baghouse compartment-in-service rotations. The commenter states that the rule is proposing a performance test every 5 years; taking 6 months to complete a set of tests to meet the rule would be incredibly arduous and costly.

Response to Comments 50 - 60: We agree with commenters on the need for the regulation to define more clearly what constitutes representative process operating load during performance testing. There are generally three testing scenarios each with different definitions of representative operating conditions. First, if the source uses CEMS (Hg, HCl, or SO_2) to determine compliance with the limit that applies over a 30-day averaging period, the rule need not specify any minimum process operating conditions. Compliance is based on a direct measure of emissions in units of the standard for the entire 30-day averaging time for all periods the process operates regardless of load conditions.

The second scenario applies to the use of PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit. This includes continuous compliance with an operating limit based on measurements from the PM CPMS rather than an emissions limit. That operating limit is derived from data collected during a short term (three test run) performance test for either filterable PM measured with Method 5 or non-Hg metals measured with Method 29. For the purposes of establishing a representative operating limit, the rule will specify that the unit be operated at maximum normal operating load conditions during the performance test period. We understand that actual maximum normal operating load for a particular facility is unit dependent but we expect it will be generally between 90 and 110 percent of design capacity. The rule will require the maximum normal operating load condition be maintained during each test run only (e.g., a few hours at a time) allowing for some operational flexibility for a performance test period that extends over more than one day.

The third scenario applies if the source owner elects to conduct frequent performance testing in lieu of continuous monitoring. In such cases, the rule will specify that the unit be operated at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test period. As noted above, actual maximum normal operating load for a particular facility is unit dependent but we expect it will be generally between 90 and 110 percent of design capacity. Maintaining this high load operating condition need not be continuous during the time it takes to complete all of the performance testing but is required only during each test run.

7. SO_2 CEMS issues.

a. Comments related to LEE (testing/monitoring).

Comment 61: Commenter 17800 states that in proposed section 63.10021(a)(11)(iv) and (v), the EPA proposes to require sources using PM CEMS to report "performance test data, except opacity data" and "relative accuracy test audit data" electronically using ERT starting January 1, 2012 (FR Vol.76, No. 85, p. 25,117) and section also requires the reporting of "performance test data, except opacity data" and "relative accuracy test audit data" for LEEs (FR Vol. 76, No. 85, p. 25,117-18). According to the commenter these provisions do not make sense because 1) EGUs using PM CEMS and LEEs do not conduct "relative accuracy test audits" (RATAs); 2) PM CEMS are subject to different tests (RCAs and RRAs); 3) LEEs comply by initially demonstrating applicability with emission tests and thereafter by fuel analysis and therefore LEEs have no monitoring systems upon which to conduct RATAs; and 4) with respect to "performance test data," the provisions are duplicative of a more general provision the EPA proposes. Commenter states that the EPA needs to reconcile this language so it makes sense.

Response to Comment 61: The final rule does not contain the cited text. The recordkeeping and reporting provisions in the final rule have been clarified to streamline reporting under this rule.

Comment 62: Commenter 17881 states that section 63.10021(a)(17)(ii) makes no sense because the whole point of being a LEE is to avoid stringent monitoring requirements (i.e., CEMS) and therefore if not equipped with a CEMS how would one submit a CEMS performance test and RATA.

Response to Comment 62: The EPA agrees and the final rule has been amended to remove section 63.100021(a)(17)(ii).

Comment 63: Commenter 17767 states that the qualifications for the Hg LEE status are egregiously costly because they would require stack testing company to sample for 28-30 days using Method 30B. Moreover, the commenter states that the three 10-day runs wouldn't be achievable at their stacks due to the scrubbed stacks' high moisture content which can foul the sorbent traps at week-long sampling durations. The commenter strongly suggests the EPA revisit this portion of the proposed rule in consultation with experienced outside experts.

Response to Comment 63: Under the final rule, all Method 30B tests are to be run on a 30 day basis. The maximum run length for a sorbent trap is set at 15 operating days for both Method 30B and a sorbent trap monitoring system. As long as the criteria for sampling within the calibration range of Method 30B are met, the source may reduce the sampling runs to shorter than 15 days as long as the total sample time of all runs is 30 days.

Comment 64: Commenter 17868 states that it is unclear whether the EPA intended the fuel input limit on Hg, and additional operating limits on Hg controls and load apply to LEEs. The commenter states that they should not.

Response to Comment 64: The operating and fuel limits have been removed from the final rule.

Comment 65: Commenter 17868 states that LEE status should be available to new units.

Response to Comment 65: The final rule retains the proposed approach – no LEE for Hg for new units. Given the emission rates established for these units, EPA does not believe the LEE option is appropriate.

Comment 66: Several commenters (17808, 17870, 18025, 18031) support the LEE approach but recommend continuous compliance methods the commenters feel are less burdensome. Commenters 17870 and 18031 recommend instead of monthly fuel tests provide an option to conduct annual Method 30B test to demonstrate emissions are less than 10% or the applicable limit or less than 22.0 pounds per year. If a LEE unit exceeds LEE limits, commenters propose that it revert back to more frequent performance tests (e.g., quarterly, as recommended below); the subsequent year, if the unit can, again, demonstrate LEE status through reduced utilization or a lower emission rate, it would return to annual stack tests under the LEE provisions.

Response to Comment 66: The final rule establishes a process similar to that suggested by this commenter. If a unit qualifies as an LEE for Hg, then annual testing is the only ongoing requirement. However, if the unit tests at above 10% of the standard, the LEE status is lost and the source must move to install, certify, operate and maintain an Hg CEMS or sorbent trap monitoring system. Specific testing requirements will apply in the interim prior to the CEMS or sorbent trap monitoring system being certified.

Comment 67: Several commenters (17808, 17870, 18025) also recommend allowing sources to schedule their annual performance tests at any time during a 12-month cycle. The commenters state that some of these LEEs may be smaller units with low capacity factors and may go several months without operating, and allowing flexibility in scheduling stack tests will avoid unnecessary air pollution emissions and reduce costs for these units operating well below the proposed standards. Additionally, state the commenters, this would allow companies to align testing under this rule with existing state testing requirements.

Response to Comment 67: The rule specifies a maximum interval between tests based on the cycle of testing required, but does not specify a minimum. Of course, if tests are conducted close together, the next scheduled test would be accelerated so that the maximum time between tests is not exceeded.

Comment 68: Commenter 17870 recommends that fuel testing be maintained as an alternate monitoring method for LEE units; it is suggested that the frequency of fuel testing be reduced to each shipment of oil received. According to the commenter, Hg concentration differences should be negligible in comparison of Method 3013 and fuel analyses for oil-fired units.

Response to Comment 68: The operating and fuel limits have been removed from the final rule.

C**omment 69:** Commenters 17808 and 17870 state that for non-Hg HAP, LEEs have the option of conducting an annual performance test to demonstrate that emissions are less than 50 percent of the relevant emissions standard.

Comment 70: Commenter 18025 states that the rule should clarify the requirements for oil-fired and coal-fired LEEs. The commenter believes this will help reveal where gaps may be occurring.

Response to Comments 69 - 70: The final rule eliminates the fuel sampling requirements. For LEEs, the rule requires annual Method 30B testing for Hg if the initial Method 30B test qualifies the unit as an LEE for Hg. To qualify as an LEE for a non-Hg pollutant, the rule requires 3 years of performance tests with each completed test below 50% of the emission standard for the applicable pollutant. If that occurs, the source can switch to testing once per year for that pollutant but must revert to quarterly testing or other monitoring options if a performance test exceeds that 50 percent threshold.

Comment 71: Commenters 17808 and 179227 request clarification that LEE status is available to all subcategories and all HAP, not just Hg from coal units. According to the commenters, the discussion of LEE status in section 63.10005 and in the preamble of the rule suggest that the EPA intends the LEE provisions to apply to all subcategories, but monitoring requirements for other HAP and fuels are not specified in Table 5.

Response to Comment 71: The EPA will clarify that the LEE status is available to all subcategories and HAP.

Comment 72: Commenter 17927 asks whether if a source is determined to be a LEE and maintains its status as a LEE in accordance with the requirements of the rule, the source will be required to install a CMS if it does not have CMS for the applicable pollutants (e.g., PM, HCl, Hg).

Response to Comment 72: For Hg, the answer is no, assuming the source maintains its LEE status. For PM and HCl, a CPMS or CEMS is not required under any condition. It is an option, but a source can instead opt for quarterly testing.

8. LEE Applicability Threshold

Comment 73: Commenter 17785 recommends that for LEEs the EPA set fuel concentration standards for Hg that are, based on the demonstrated Hg control efficiency in compliance test, equivalent to 22 lb/year of Hg emissions. According to the commenter, it does not seem appropriate to apply the fuel sampling criteria for determination of compliance of LEE units, if these fuel limits would represent emission lower than the LEE Hg threshold of 22 lb/year. The commenter believes their waste coal plants are expected to continue to emit less than 5 lb/year, so it is likely that the imposition of a fuel Hg limit based on average Hg or 90th percentile Hg would set an effective Hg emission limit that is likely less than 10 lb/year. According to the commenter, this is an unnecessarily strict emission limit and may cause a unit to lose its LEE status simply as a result of fluctuation of Hg in fuel.

Response to Comment 73: The final rule has removed the requirements for operational limits and fuel sampling and analysis for LEE units. Compliance with LEE status will be achieved through annual performance tests.

Comment 74: Commenter 17620 agrees that units that have demonstrated an ability to consistently limit emissions substantially below applicable limits should be eligible for reduced monitoring. However, the commenter recommends that the thresholds for reduced testing be based on a demonstrated record of performance over several years, be accompanied by parametric monitoring and/or compliance assurance monitoring and be set at more protective levels. The commenter states that the EPA has proposed to allow reduced testing for sources based on the results of a single test and has proposed to allow reduced testing where the source’s emissions are as high as 70% of the applicable limit, and the EPA’s proposal would allow a unit to qualify for reduced testing for Hg if the source’s emissions were either less than 25% of the applicable limit or less than 22 lb/year. In contrast, states the commenter, in calculating the

Hg MACT floor, the EPA asserts that even the best performing units can reasonably expect year-over-year stack test results to vary by a factor of 50 because of statistical variability, operational variability, measuring system variability and variability in fuel. The commenter states it is convinced that year-over-year compliance testing of well-performing units will demonstrate the variability that the EPA asserts in its MACT floor proposals but suggests that the EPA be consistent in its treatment of these issues.

Response to Comment 74: The LEE provisions demonstrate the Agency's desire to provide incentives for owners or operators to provide additional emissions reductions. The provisions offer easy entry, as the initial performance testing results can be the basis for qualifying, but strenuous maintenance requirements, for the results of every test conducted for any reason must meet the qualifying requirements. Should those requirements not be met by just one subsequent test, LEE status is lost and the source owner must provide qualifying data from three years of results before becoming eligible for LEE status. LEE status for Hg is achieved through a 30-day performance test repeated annually, that documents emissions are less than 10% of the standard or less than 29 lb/year. If results from a single test are above that threshold, the source will have to use Hg CEMS or a sorbent trap monitoring system. For non-Hg LEE status, the source must demonstrate that test results are below 50% of the emission limit. As mentioned before, should test results from an EGU show emissions above the LEE threshold for any reason – including variability – LEE status is lost

Comment 75: Commenter 17873 asserts that the LEE standard for Hg (10% of the MACT standard) is low and impractical. According to the commenter, the proposed limit of 0.12 lb/MMBtu is near or below the in-stack method detection limit, and it will be very difficult to confidently prove compliance under any testing regimen. The commenter states that the LEE standards for other HAP are 50% of the MACT standard. Commenter states that while it understands the heightened focus on Hg, the EPA has not sufficiently demonstrated the need for a LEE standard threshold less than that for other HAP, and therefore propose a consistent LEE Hg standard of 50% of the Hg MACT standard (or 0.06 lb/TBtu).

Response to Comment 75: The EPA disagrees with the commenter. Method 30B has been shown to be capable of measuring Hg catches down to 1 ng within QA/QC criteria of the method. With increased time as allowed in LEE testing, Method 30B is technically capable of demonstrating emissions at the LEE threshold. In addition, the mass alternative provides another option for demonstrating LEE status.

Comment 76: Commenter 17767 states that the 22 lb/yr Hg threshold for LEEs was set using fifth percentile of the 1,091 operating units (5% of the total mass being determined as a "reasonable cut point" during the CAMR development process). Commenter presumes that, in light of the Hg calculation errors discovered in the proposed rule's foundational data since its publication in the Federal Register, the agency will revisit the lb/yr cut-off calculation at the reasonable fifth percentile level.

Response to Comment 76: The agency disagrees with the comment, for the Hg LEE threshold was determined independently from the proposed rule's Hg limit. The rule contains no change to the Hg LEE threshold.

Comment 77: Several commenters (17754, 17812, 17838, 18963) state that LEEs with Hg emissions below 50% of either of the proposed LEE thresholds should be provided an option to demonstrate continuous compliance through annual stack testing, and should not be required to conduct monthly fuel analyses so long as the fuel supplier does not change. According to the commenters, annual testing could consist of three 120-minute test runs performed using EPA Method 30B. Sources emitting at very low Hg emission rates are highly unlikely to show emissions that would exceed the LEE threshold.

Response to Comment 77: The final rule has been amended to remove the fuel sampling and analysis requirement of the LEE option. In lieu of fuel sampling, annual LEE performance testing will be required.

Comment 78: Several commenters (17754, 17838, 18963) state that an alternative to LEE compliance is to use a fuel-factor based approach. According to the commenters, the EPA could revise the specific fuel-factor based approach currently required under the proposed rule. The commenters believes that the requirement to use the 90th percentile confidence level to determine the operating limit for Hg is improper, because the use of such value could cause a LEE to lose its LEE status, even though the unit's actual Hg emissions remain substantially below the LEE thresholds. The commenters recommend a four step approach:

Step 1: Conduct an initial performance test (and every 5 years thereafter) to demonstrate the unit's LEE status and during the performance test determine and record the average control efficiency achieved over the three test runs. The initial performance test (for demonstrating LEE status) would be conducted over a 28-30 day period; subsequent performance testing, on a 5 year cycle, should consist of three 120-minute test runs, performed using Method 30B.

Step 2: Determine the Hg content in the fuel on a monthly basis.

Step 3: Calculate the average Hg content in the fuel on a quarterly basis (i.e., by averaging the Hg content levels measured during the 3 months comprising the quarter).

Step 4: Apply the control efficiency determined during the stack test to the quarterly average Hg fuel content. If the projected annual emission rate (calculated by multiplying the control efficiency determined during the performance test by the Hg fuel content) is less than or equal to 50 percent of the 22 lb/yr LEE threshold (i.e., 11 lb/yr), then the owner/operator remains subject to this process for demonstrating that the facility continues to qualify as a LEE. However, if the calculated fuel factor value is greater than 11 lb/yr, then the owner/operator shall conduct a stack test to demonstrate that the unit's Hg emissions are in fact below the 11 lb/yr level. If the unit's actual Hg emissions determined from such stack testing remain less than or equal to 11 lb/yr, then the owner/operator remains subject to this process for demonstrating that the facility continues to qualify as a LEE. If the unit's actual Hg emissions are greater than 11 lb/yr, but less than 22 lb/yr, then the owner/operator shall thereafter comply with the continuous compliance demonstration requirements for LEEs with emissions below the 22 lb/yr threshold for Hg (i.e., such unit would no longer qualify as a "very low emitting EGU"). To the extent that a facility thereafter demonstrates through performance testing that its projected annual Hg emissions are less than 50 percent of the LEE threshold of 22 lb/yr, then the facility could return to very low emitting EGU status, and demonstrate continuous compliance in accordance with the foregoing methodology. In other words, simply because a single stack testing result suggests that the facility's annualized Hg emissions could exceed 11 lb/yr, the facility should not be perpetually precluded from re-establishing very low emitting status.

Response to Comment 78: The final rule has been amended to remove the fuel sampling and analysis requirement of the LEE option. In lieu of fuel sampling, annual LEE performance testing will be required.

Comment 79: Commenter 17927 questions whether an EGU that fires coal or solid-oil derived fuel that has not determined if it qualifies for LEE EGU status per the proposed rule have the option of any of the testing options listed in Table 5 (performance testing, Hg CEMs, sorbent trap monitoring system, or 28-30 day LEE testing) for the initial performance test.

Response to Comment 79: Initial compliance for coal or solid-oil derived fuel may only use the Hg CEMS, sorbent trap monitoring system or LEE testing options.

Comment 80: Commenter 17927 requests that the EPA clarify whether an existing coal or solid-oil derived fuel-fired unit the performs a 1-day performance test per Table 5 after the final rule is published and within the 3-year compliance deadline for affected units have the option of complying with the LEE requirements.

Response to Comment 80: LEE requirements for Hg must be met with a 30 day Hg performance test. For other pollutants, LEE status requires a series of periodic tests that show emissions are routinely below 50% of the standard for the applicable pollutant.

Comment 81: Commenters 17627 and 17718 believe that the EPA should reconsider the frequency and types of monitoring that are appropriate for various subcategories and provide an exemption for low capacity factor and LEE units.

Response to Comment 81: The EPA has reconsidered and amended the final rule to alter the frequency and monitoring requirements for low capacity and LEE units.

Comment 82: Commenter 17781 states that while it is not unreasonable to set a qualification level, the EPA has provided no rationale for setting different thresholds for Hg (10%) and all other HAP emission limits (50%).

Response to Comment 82: Because of the evidence of widespread contamination with a risk of significant adverse health and environmental effects associated with Hg emissions and because Hg has a high degree of persistence, EPA believes that it is appropriate to set a more precautionary threshold for allowing a source conduct periodic emissions testing in lieu of monitoring continuously for compliance with the Hg emissions limit.

As mentioned elsewhere in this document and rule preamble, mercury is a powerful neurotoxin that persists in the environment indefinitely and its emissions warrant special attention.

Comment 83: Several commenters (17781, 17838, 17902) state LEE units that operating outside the operating limits established during the most recent performance test should disqualify the unit from LEE status. See section 63.10006. The commenters recommend that operating outside the operating limits established during the most recent performance test should trigger a requirement to conduct a timely LEE qualification re-test based upon an expanded operating limit (consistent with the original operating limit excursion). Commenter 17781 states that if the results of the LEE qualification re-test indicate that the unit continues to qualify for LEE status (i.e., meets section 63.10005(k)(1) and (2)), then the EGU should maintain its LEE status; if the testing does not show that the EGU continues to meet LEE status, then the EGU should be subjected to enhanced monitoring (i.e., be required to meet the provisions of section 63.10006(c)(1) and (2)).

Response to Comment 83: The final LEE provisions and other final monitoring requirements do not provide for this suggestion. The only parameter monitoring that applies is a PM CPMS, and the expectation if that I used is that a source is unlikely to opt for LEE status after the CPMS is installed.

Comment 84: Commenter 18014 states that the fuel sampling requirements for LEE units are ambiguous and provide no compliance value since the rule does not require the establishment of a fuel input operating limit. According to the commenter, the requirements do not address single-fuel units, changes in fuel type, or units that burn or co-fire multiple fuels, and presumably, LEE units would follow an analogous procedure to non-LEE units and reassess the ability to meet LEE status based on the new fuel type/blend. According to the commenter, this would require sources that burn multiple fuel types or blends to establish a fuel-input operating limit during the initial compliance demonstration. The commenter recommends that consistent with the non-LEE requirements, the EPA should remove the arbitrary monthly sampling requirement and allow sources to conduct fuel sampling only when there is a change in the fuel type and that for single-fuel units, the EPA should specify that these units are not required to comply with any of the fuel sampling requirements.

Response to Comment 84: The final rule has been amended to remove the fuel sampling and analysis requirement of the LEE option. In lieu of fuel sampling, annual LEE performance testing will be required.

Comment 85: Several commenters (19536, 19537, 19538) state that the EPA should discard the proposed "Low Emitting Units" monitoring protocols. According to the commenter, because the EPA's standards are based upon a 99% UPL a majority of plants should be able to generate test data sufficient to claim such "low emitting" status. The commenter states that as summarized in Table X-1, the EPA's proposed MACT standards exceed the tested emissions of the plants for which the EPA has data by the ratio greater than 2 for all non-Hg HAP (i.e., the tested emissions are below 50% of the standard), and greater than 10 for Hg (i.e., tested emissions are less than 10% of the standard). As a result, states the commenter, almost all existing and new units will likely be able to exempt themselves as LEEs; in combination, the EPA's variability adjustments and LEE exemption allow most units to avoid any significant monitoring of emissions.

Comment 86: Commenter 18487 urges the agency to either discard its "Low Emitting EGU" provisions, or to substantially revise them; if the emissions variability asserted by the agency exists, the threshold conditions required for qualification as a "low emitting" unit provide no significant assurance that emissions will remain below the proposed standards.

Response to Comments 85 - 86: The agency disagrees with the comment to discard the incentive for an EGU owner or operator to seek LEE status. While emissions data collected as a result of the ICR and adjusted using the UPL calculation shows an EGU's potential variability, well-operated EGUs – such as those qualifying for LEE status - are expected to have much less variable emissions. The Agency believes that the requirement to revert to the original monitoring frequency should subsequent emissions testing show the EGUs no longer meet LEE status will keep source owners or operators interested in maintaining LEE status.

Comment 87: Commenter 17402 supports the LEE alternative compliance with some modifications. The commenter recommends that any facility that either significantly over-complies with the emissions standards, or is overall a low emitter by mass in the case of Hg, should be afforded significant leeway in terms of performance testing and fuel analysis. Most of the commenter's Illinois facilities installed ACI controls in years 2008 and 2009, and have reduced Hg emissions below 22 lb/yr. The commenter states that such plants conduct semiannual performance stack tests utilizing Method 30B for compliance, and use sorbent traps for tracking ACI effectiveness. According to the commenter, the rule should be clear that low emitters can use Hg monitors to track performance, rather than for compliance. The commenter notes that this approach is consistent with the EPA's long history of exempting low-emitting sources from monitoring or allowing those sources to use less rigorous and lower cost monitoring technology, rather than requiring continuous monitoring. The commenter states that the EPA first used a *de minimis* exemption to exempt certain units from Acid Rain CEMS monitoring regulations in 1993 and that similarly, in 1998 the EPA included low emitter provisions with inventory-based "cutoff points" for SO_2 and NO_X emissions.

Response to Comment 87: The Agency believes the rule provides owners or operators of LEEs with significant leeway concerning maintaining LEE status, given that Hg emissions testing need only occur annually and non-Hg emissions testing need only occur once every 3 years. With that incentive for reduced testing frequency comes the responsibility for ensuring units continue to meet LEE status. While the agency expects owners or operators will want to ensure proper operation by monitoring control device effectiveness, along with other relevant items, the agency also expects adherence to LEE status requirements, meaning that should measured emissions exceed the LEE threshold, LEE status would become revoked.

Comment 88: Commenter 17902 recommends that the EPA should clarify that for LEE qualifiers it exempts units from a CEMS requirement as well as bi-monthly performance testing. Also it should not require monthly fuel analysis- this should only be required when there is a fuel switch or allow for obtaining the data from the fuel supplier. For example, states the commenter, a unit could qualify for LEE for non-Hg metals by being less than 50% of the total PM limit (even if HCl or Hg emissions are not LEE status). According to the commenter, this unit would not be required to install a PM CEMS and would require fuel analysis only when there is a fuel change plus repeat the performance test every 5-years.

Response to Comment 88: LEE status is unique to each regulated HAP. A source may achieve LEE status for one HAP while not for another.

9. LEE fuel sampling issues.

Comment 89: Commenters 17767 and 17807 express concern over the fuel sampling and the potential for variability. Commenter 17767 states that there is no discussion of allowable tolerances to the Hg, chlorine, and HAP Metal content limits set for ongoing qualification for LEE status. The commenter states that it is unreasonable to assume that, given the natural variability within even the same coal seam as well as the error of the analysis methods, the constituents will be consistently below the concentrations observed during the performance testing; this would make the LEE methodology undependable and functionally unworkable. Commenter 17807 states that a single date point is not sufficient to demonstrate emissions in excess of the LEE. Commenter notes that in order to provide assurance that the fuel profile is meeting the limits set during the initial compliance test, coal would need to be stored for some period of time prior to burning. According to the commenter, it would be impractical and environmentally imprudent to store coal for extended periods of time just to wait for laboratory analytical results.

Comment 90: Commenter 17928 states that under the LEE an oil analysis required to comply with the input-based standards requires very low detection limits not typically available in national labs. According to the commenter, there are a limited number of laboratories that do these tests to the limits of detection needed; these analyses are too costly to have performed on the regular basis proposed in the rule; and the oil-fired units typically have low capacity factors, another factor that argues against regular oil testing.

Comment 91: Commenter 17800 states to qualify for LEE status for Hg emissions the test Method 30B is a vapor phase only test method and does not account for any particle bound Hg emissions. The commenter recommends that an initial performance test for Hg emissions include an accounting of any particle bound Hg; an option would be to demonstrate that total Hg emissions is less than 10% of the Hg emission limit or less than 22 lb/yr using a test method that measures total Hg. The commenter states that if the particulate bound Hg is 5% or less than the total, subsequent testing could measure only the vapor phase Hg emissions; if EPA Reference Method 29 or ASTM Method D6784-02 (2008) is used to determine total Hg emissions, only three 1-hour test runs would be required.

Comment 92: Commenter 17805 does not believe it is necessary to sample larger volumes during stack testing to comply with LEE status. The commenter states that current stack test methods should be sufficient for determining compliance with LEE status and a unit is still required to conduct monthly fuel sampling per section 63.1 0006(c) that would serve to demonstrate coal variability. Commenter believes it is burdensome to require parametric limits to be applied to LEE units as well, since existing controls for other pollutants, such as SO_2 in consideration of a potential HCl LEE unit, would be adjusted as appropriate for the pollutant emissions that are monitored by the CEMS. According to the commenter, this would serve to keep HAP emissions consistent, and again, fuel analysis is conducted monthly for LEE units to evaluate potential increases in constituents that might result in higher emissions.

Comment 93: Commenter 18539 is concerned that the proposed rule does not adequately address the operating characteristics of fuel-flexible units. According to the commenter, the nature of monitoring requirements, both initial and every 5 years, in addition to parametric monitoring, will hinder many sites from using multiple fuel sources and types where there was not a restriction before this rule. The commenter states that this aspect will not only diminish the operational and financial flexibility of the facility, but it has the potential to virtually prohibit large segments of fuel suppliers that have elevated metals and other HAPS, and all the while there may not be any economical substitute for the unusable fuel, thus causing extreme localized economic and employment losses.

Response to Comments 89 - 93: The final rule has removed the requirements for operational limits and fuel sampling and analysis for LEE units. Compliance with LEE status will be achieved through performance tests. Increased sampling volumes may not be necessary, but must be sufficient during LEE testing such that the in stack detection limit is less than the LEE threshold. See responses to comments elsewhere in this document relative to particulate Hg measurements.

10. Belt sampling.

Comment 94: Commenters 17730 and 17775 state that section 63.10008 includes very specific requirements for collecting composite fuel samples. The commenters state that for belt sampling, the rule requires that the belt be stopped. Commenters believe that this requirement is unreasonable because it would not allow for the use of continuous belt samplers; many belts cannot be restarted with coal on them because the belt is too heavy for the motor to start. The commenters state that for sampling piles or trucks, the rule requires (among other things) use of a “square shovel,” collection of samples at a depth of exactly “18 inches,” collection at five locations “uniformly spaced over the surface of the pile,” and breaking of pieces larger than exactly 3 inches (proposed in section 63.10008(c)(2)(ii) and (d)). The commenters note that they do not object to the intent behind these proposed requirements, representative samples can be taken with shovels of other shapes, at depths greater or less than 18 inches, and without measuring the actual size of individual coal pieces. The commenters believe these requirements are excessively prescriptive and that the EPA should remove the prohibition on moving belt samplers, and re-examine and moderate the pile sampling requirements to provide more realistic criteria (e.g., use the same shovel for all samples, collect samples at a uniform depth of approximately 18 inches, and break apart large pieces (e.g., pieces greater than 3 inches).

Response to Comment 94: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS.

11. Sorbent trap.

Comment 95: Commenter 17870 supports the use of sorbent traps for units not equipped with CEMS.

Response to Comment 95: The EPA thanks commenter for its comment.

Comment 96: Several commenters (17696, 17775, 17868, 17800) state that the EPA should provide an explanation for the difference in the days the sorbent trap is used. According to the commenters the rule provides 14 days for non-LEE units and 10 days for LEE units.

Response to Comment 96: The final rule will be amended to allow 15 days for LEE unit performance tests.

Comment 97: Commenter 17696 does not believe that there should be any limit on the number of days that sorbent traps may be used to sample Hg. The commenter has periodically used sorbent traps over the past 2 years at five facilities in preparation for continuous Hg emissions monitoring requirements that will become effective next year under the Illinois Mercury Rule, 35 Ill. Admin. Code part 225, subpart B. In the commenter's experience, while sorbent traps are routinely changed out within 14 operating days, there is no reason to invalidate a pair of sorbent traps simply based on the duration of their use in the event unforeseen circumstances prevent removal of the traps on schedule. The commenter states that notably, the Illinois Mercury Rule does not restrict the number of days a sorbent trap may be used. (See 35 Ill. Admin. Code Part 225, Subpart B, App. B, Continuous Emission Monitoring Systems for Mercury, Exhibit D, Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems.) Commenter states that such a prescription on the duration a trap may be used is unnecessary because the length of time a trap may sample varies from stack to stack based on SO_3 concentrations and other miscellaneous factors.

Comment 98: Commenter 17696 states that the determinative factor for the validity of sorbent traps should be the QA/QC criteria already in place for the sorbent trap monitoring method, and not the duration of use. If a trap samples for too long, states the commenter, it will either fail the breakthrough or spike performance criteria (see proposed App. A, 1.5.2.1 (requiring compliance with 40 CFR Part 60 PS 12B QA/QC criteria, which includes spike recovery and vapor phase breakthrough specifications)). According to the commenter, those QA/QC criteria are, by themselves, a powerful incentive not to sample for too long. However, states the commenter, if an EGU is forced to use a sorbent trap to sample for a longer duration than expected because of, for example, bad weather or mechanical problems with the stack elevator, the EGU should still be able to use the trap data if the QA/QC criteria are met; the duration of use does not itself adversely affect the performance of the trap or the validity of the monitoring result. However, states the commenter, if the EPA does not eliminate the proposed duration limit on use of sorbent traps, the EPA should revise section 63.1 0005(k)(3) to allow use of sorbent traps for up to 14 operating days consistent with Appendix A, 5.2.1.

Response to Comments 97 - 98: The final rule has been amended to allow 14 days for Hg LEE testing. Issues extending the sample time by a day such as bad weather or mechanical issues can be handled on a case-by-case basis through a minor alternative monitoring requests.

Comment 99: Commenter 17927 requests clarification as to whether an existing coal or solid oil-derived unit that is found not to be an LEE is required to install a sorbent trap monitoring system to demonstrate continued compliance.

Response to Comment 99: The source would be required to install sorbent trap monitoring system or Hg CEMS.

12. Oil-Fired testing.

Comment 100: Commenter 17818 states that they agree with the EPA's proposed requirement for units firing residual liquid oil fuels. However, the commenter believes that the testing requirements are excessive for units that utilize distillate liquid oil fuel, and that fire no residual fuel oil; after the initial performance test such units should be eligible for compliance through fuel testing and monitoring requirements similar to that proposed by the EPA for "limited-use liquid oil combustion units." The commenter states that that there are relatively few variables in distillate oil combustion practices for a given unit design and that there is relative consistency in distillate fuel oil quality and chemical composition such that there would be little variability in the emission of HAP metals, HCl, or HF.

Comment 101: Commenters 17716 and 18498 state with respect to the EPA solicitation of comment on "a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil and are inoperative the remainder of the year" (76 FR 25027/3) that limited operation may preclude the ability to conduct stack testing. According to the commenters, limited operation that precludes the ability to conduct stack testing is not a phenomenon limited to only liquid oil-fired units; timelines for completing subsequent performance tests for all units should be adjusted to account for the operating status of the unit.

Comment 102: Commenter 18444 states that new and existing EGUs using distillate oil, especially ultra-low sulfur oil, which is almost as clean as natural gas, do not need a particulate emission limit or testing to demonstrate compliance. According to the commenter, periodic opacity testing is not needed either; a no visible emission standard is achievable and reasonable for ultra-low sulfur distillate oil.

Response to Comments 100 - 102: The final rule has been amended to reduce all liquid oil-fired EGU performance testing to quarterly and to subject limited use (capacity factor less than 8% in a 24 month block average) sources to work practice standards in lieu of numeric emission limits. In addition, the fuel sampling and analysis requirements have been removed. The only fuel-related provision is an option for liquid oil-fired units to demonstrate compliance with the acid gas standards by documenting that fuel moisture content remains no greater than 1.0%. This demonstration is based on monitoring results or fuel supplier certifications.

13. Measurement issues.

Comment 103: Commenters 17724 and 17729 state that for new units the limits are so low that adequate test methodologies to demonstrate compliance do not exist. According to the commenters, without accurate testing methodologies, contractors will not guarantee that potential emission control technologies will meet the proposed standards; without accurate test methodologies and vendor guarantees, financing of new facilities will be virtually impossible to secure; and this will effectively preclude the construction of any new coal-based units. Commenter 17729 notes that this will affect the balance of fuel diversity in the energy supply.

Response to Comment 103: The final rule new source emission limits have been adjusted to three times the RDL to ensure the required test methods can demonstrate compliance.

Comment 104: Commenter 17716 states that in section 63.7520(d) the EPA specifies a minimum sampling time of four hours for each test method, following the procedures used to establish the MACT floor data. Commenter asserts that 4 hours seems excessive for certain pollutants. According to the commenter, the required sampling times should be reevaluated and/or alternative minimum sample volumes should be provided for each method, taking into account representative analytical detection limits and emissions standards that are fully adjusted for non-detect values.

Response to Comment 104: The EPA has reviewed the final emission limits, sample volumes and RDL to ensure that a realistic sample volume and duration is provided. Sources may also request alternative sample volumes as outlined in 40 CFR 63.7.

Comment 105: Commenter 17718 states that the EPA should clarify the specific testing (initial and subsequent) and monitoring requirements for a unit with bypass capability. Specifically, states the commenter, the EPA should clarify whether initial testing of the bypass emissions need to be tested within the 180-day timeframe described in the proposed language. Alternatively, states the commenter, setting a firm testing timeframe on bypass stack emissions seems overly burdensome. According to the commenter, creating emissions (and incurring costs) by switching a unit into bypass mode that would not otherwise have been used simply in order to perform emission testing appears to create unnecessary burden.

Response to Comment 105: Due to the potential for technical issues with the use of CEMS or a PM CPMS on the bypass stack, the final rule provides the option to either install and operate a CEMS or PM CPMS in the same manner as a main stack, or to treat hours in which the bypass stack is used as monitor downtime.

14. Fuel sampling issues.

Comment 106: Commenter 17716 suggests that the fuel sampling, analysis and calculations proposed in section 63.10021 could be applied for uncontrolled units and believes that for controlled units, annual testing is sufficient to demonstrate proper operation of control devices. Commenter 17716 believes the provisions for fuel sampling, analysis, and calculation of expected emission rates proposed in section 63.10021 should apply to liquid oil-fired sources.

Comment 107: Commenter 17402 states that the EPA should allow compliance through annual performance testing rather than bimonthly or monthly, when combined with monthly fuel sampling for facilities that use a single fuel type. According to the commenter, data in the docket indicate that over the long term, facility compliance is fairly consistent despite the potential for variability in fuels and operations to affect emissions levels. The commenter states that the EPA should allow facilities to comply with the performance testing requirements on an annual basis by coupling the less frequent stack testing with more frequent fuel sampling.

Comment 108: Commenter 17402 states that the EPA should clarify when fuel sampling requirements apply. For example, states the commenter, fuel sampling should not be required for units that employ CEMS. According to the commenter, for units that only burn one type of fuel, sampling should only be required monthly if being used as part of a continuous compliance program, as the variability impact is limited. Most importantly, states the commenter, the EPA should not penalize units that burn low contaminant fuel by setting their fuel limits based on their average fuel content during the performance tests. According to the commenter, instead, the EPA should set the fuel limit based on HAP reduction performance of the unit, and set the fuel contaminant level at one that guarantees compliance with the fuel limit taking into account the standard variability of HAP in that source's fuel.

Comment 109: Commenter 17730 states that the EPA should moderate the alternative procedures in proposed section 63.10008. The commenter states that all fuel analysis under the rule must be conducted according to an approved site-specific plan and according to specific procedures for sampling, preparation, and analysis. According to the commenter, the EPA's proposed requirements are in many instances overly prescriptive; the primary objective should be to obtain fuel samples that are representative of the fuel that is being combusted. According to the commenter, because there is so much diversity in how fuel is received, stored, and processed at individual facilities, as well as what is actually contained in the mine, the EPA needs to allow more flexible procedures to accomplish the primary objective. The commenter states that under proposed section 63.10008(b)(l), the proposed plan must be submitted to the Administrator at least 60 days before the fuel analysis. Because some of the information required to be included may change from analysis to analysis the commenter assumes the EPA will require a new plan. For example, states the commenter, the plan must include identification of all fuel types anticipated to be combusted and whether the source or fuel supplier will conduct the analysis (proposed in section 63.10008(b)(2). The commenter states that although it might be possible to submit that information 60 days in advance of the initial demonstration and receive approval before conducting the analysis, it may not be possible for subsequent analysis in response to changes in fuel type or fuel mixtures (since those might occur with less notice or planning). According to the commenter, the requirement to submit a new or revised plan also makes little sense if monthly analysis is required. The commenter believes that the EPA should either remove the requirement for advance submittal and approval of a plan after the initial compliance demonstration, or remove the requirement to include in the plan information that might change.

Response to Comments 106 - 109: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS. Compliance with emission limits will be shown with periodic (quarterly) performance testing, CEMS, or a combination of annual emission testing and PM CPMS.

15. Fuel limits.

Comment 110: Commenter 17705 encourages the EPA to limit the requirement to establish maximum fuel inputs to sources that are uncontrolled and solely relying on fuel analysis to demonstrate compliance with a numeric standard. The commenter states that the characteristics of fuel, in particular coal fuel, can vary between shipments, so it is problematic to establish any type of maximum value based on a one-time, short-term performance test, and further, for units that are controlled, relying on a fuel input limit does not adequately account for emissions reductions achieved by the control devices. According to the commenter, for controlled units that do not elect to use CEMS to demonstrate compliance, it would be more appropriate to establish parametric monitoring for the control devices (coupled with period performance testing) than unnecessarily constrain fuel supplies through non-representative "maximum" fuel inputs.

Response to Comment 110: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS. Compliance with emission limits will be shown with periodic (quarterly) performance testing, CEMS, or a combination of annual emission testing and PM CPMS.

16. CEMS only.

Comment 111: Commenter 17715 states that it is not clear in the proposed rule that installing and operating CEMS for the regulated HAP and surrogates will relieve a source of the burden of also monitoring compliance with operating limits on control equipment based on a performance stack test. According to the commenter, the EPA should require no additional proof of compliance than a properly calibrated and installed CEMS would provide, and the EPA should format both the language and tables in the rule to clarify its intent as it relates to CEMS used for demonstrating compliance.

Response to Comment 111: No other monitoring is required if a source uses a CEMS to demonstrate direct compliance with an emission limit (including the SO_2 surrogate limit for HCl).

17. Section 63.10007(a) Site Specific Test Plan.

Comment 112: Commenter 17718 states that the EPA should provide guidance on what should be included in a site specific test plan as mentioned in proposed regulatory language of 40 CFR 63.10007(a) and referenced to 40 CFR 63.7(c). According to the commenter, the development of external QA programs with testing firms and laboratories (especially if multiple testing firms and laboratories are needed) has the potential to become extremely burdensome without clearer guidance.

Response to Comment 112: The EPA has already issued a guideline document for the preparation of site specific emission test plans. The document can be found at http://www.epa.gov/ttn/emc/guidlnd/gd-042.pdf

18. CPMS comments.

Comment 113: Commenter 1775 states that section 63.10010(h) sets out requirements for CPMS and the previously proposed PS 17 would apply to CPMS. 73 FR 59,983 (Oct. 9, 2008). The commenter objected in the PS 17 rulemaking to the proposed application of that specification to future performance specifications without revision of the individual subpart. See UARG Comments on Proposed Performance Specification And Quality Assurance Requirements For Continuous Parameter Monitoring Systems (February 5, 2009), EPA-HQ-OAR–2006–0640-0064. The commenter states that whatever specifications are necessary to support this rule, they must be proposed and promulgated in this rulemaking.

Response to Comment 113: This is no longer applicable except to the extent PS 17 would apply to a PM CPMS under this rule. Given that PS 17 is not yet final, this issue is best addressed in the response to this concern in the context of the PS 17 rulemaking, not in this rulemaking, given that the issue extends to all promulgated NESHAP standards with a parametric monitoring system potentially subject to PS 17.

Comment 114: Commenter 17775 states that the rule proposes various installation operation and maintenance requirements for “flow monitoring systems,” “pressure monitoring systems,” and “total secondary power monitoring systems.” According to the commenter, several of these proposed requirements are unnecessary or unclear: first, with respect to flow monitoring systems, depending on the fluid being measured, many systems do not use flow meters due to reliability issues, corrosion, or composition. Instead, these processes frequently use constant rate pumps. The commenter states that these pumps have a known capacity given their specific application and are either "on" or "off." As an example, states the commenter, scrubber module slurry pumps operate in this manner; the reported scrubber slurry flow rate is simply based on the number of pumps in service. According to the commenter, the EPA should make clear that flow monitoring systems are not required for any CPMS and that systems that use constant rate pumps are not subject to performance specifications (see Technical Memorandum from Richard McRanie, McRanie Consulting, "Comments on the Proposed Utility MACT Rule - Operating Parameters" (July 2011) (Attachment 11) at 18).

Response to Comment 114: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS.

Comment 115: Commenter 17775 states that the section 63.10010(h)(2)(i)(C) requirement to "Minimize the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances" is unnecessary and extremely vague. According to the commenter, the requirements in proposed subsections (A) and (B) - to properly locate the flow sensor and to use a sensor with a sensitivity no greater than two percent of the expected flow rate - are adequate. The commenter states that the term "minimize" is not sufficiently objective to be meaningful in this context, and more objective requirements (e.g., some number of diameters downstream of a flow disturbance) might not be possible to meet.

Response to Comment 115: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS.

Comment 116: Commenter 17775 states that the evaluations under section 63.10010(h)(2)(i)(D) should specifically allow for procedures that include process trending and comparisons that can indicate the flow monitor is performing properly (similar to the fuel flow to load concept in Part 75, Appendix D section 2.1.7). According to the commenter, operators should not necessarily be required to ship meters off to get NIST traceably certified each year.

Response to Comment 116: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS.

Comment 117: Commenter 17775 stated that with respect to pressure monitoring systems in section 63.10010(h)(2)(ii)(B), the requirement will be difficult to interpret as a regulatory requirement. The commenter states that the requirement in subsection (A) to provide a representative location is sufficient; however, the EPA also proposes to require that EGUs "Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water, or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less" (proposed section 63.10010(h)(2)(ii)(C). According to the commenter, this should read, "whichever is less restrictive." If a source is using a 0 to 30 psig gauge for some purpose, the 1.27 cm requirement would be the lesser error, states the commenter, but it would be a 0.06 percent error. The commenter does not believe this is what the EPA intended.

Response to Comment 117: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS.

Comment 118: Commenter 17775 states that under section 63.10010(h)(2)(ii)(D) there is a requirement to "[p]erform checks at least once each boiler operating day to ensure pressure measurements are not obstructed (e.g., check for pressure tap pluggage daily).” According to the commenter, daily checks are not warranted; pressure sensors are used in a variety of process functions (e.g., to monitor baghouse and scrubber pressure drops, slurry tank liquid levels, etc.) and have design features that ensure the pressure taps do not get plugged. The commenter states that for pressure sensors that are exposed to gases (e.g., boiler exhaust gases), the pressure taps have purge air to periodically clean them; the purges can be varied to ensure that key pressure measurements are very reliable. For pressure sensors that are exposed to liquids (e.g., scrubber slurry), states the commenter, redundant taps and a water cleaning system is frequently used; while one tap is being cleaned with water, the other tap is being used for process control. According to the commenter, while the EPA might believe it is reasonable to expect pluggage problems with pressure taps, these types of problem rarely exist, and it would be unnecessarily burdensome to expect technicians to check each pressure tap for pluggage every day.

Response to Comment 118: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS.

19. ASTM methods.

Comment 119: Commenter 1775 states that the in addition to the use of ASTM D3173 for determination of moisture content in fuel the EPA also should allow use of (1) ASTM D7582 “Standard Test Methods for Proximate Analysis of Coal and Coke by Macro Thermogravimetric Analysis,” or (2) ASTM D5142 “Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and Coke by Instrumental Procedures,” which are equivalent to ASTM D3173, except that they are automated. The EPA should reference ASTM D3302 “Standard Test Method for Total Moisture in Coal,” and ASTM D3180 “Standard Practice for Calculating Coal and Coke Analysis from As-Determined to Different Basis.” The commenter states that both ASTM D3302 and ASTM D3180 are referenced in ASTM D3173, and in addition, the following methods are currently used by EGUs for Hg, metals, and chlorine in coal and should be evaluated for inclusion without an equivalency analysis:

- EPA Method 7473 - “Mercury in Solids and Solutions by Thermal Decomposition, Amalgamation, and Atomic Absorption Spectrophotometry”;
- ASTM D4326 - “Standard Test Method for Major and Minor Elements in Coal and Coke Ash By X-Ray Fluorescence”;
- ASTM D6357 - 04 - “Test Methods for Determination of Trace Elements in Coal, Coke, & Combustion Residues from Coal Utilization Processes by Inductively Coupled Plasma Atomic Emission, Inductively Coupled Plasma Mass, & Graphite Furnace Atomic Absorption Spectrometry.”

Finally, states the commenter, a number of methods that were identified in Table 2.3 of the 2010 ICR are not included in the rule. According to the commenter, the EPA should include these methods or explain why they were excluded.

Response to Comment 119: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS. The only fuel-related provision in the final rule is an option for liquid oil-fired units to demonstrate compliance with the acid gas standards by documenting that fuel moisture content remains no greater than 1.0%. This demonstration is based on monitoring results or fuel supplier certifications without reference to any specific methods for such analyses. As for the fuel metals contat sampling and analysis, the rule no longer requires such measurement eliminating the need to specify these methods.

Comment 120: Commenter 17808 recommends the EPA set a percent water content limit for oil, rather than setting HCl and HF emissions limits for liquid oil-fired EGUs. The commenter states that ASTM test methods are available for measuring the percent water content of fuel oil (D95 and D473) and that plant operators would test each shipment received to ensure compliance with the proposed limit.

Response to Comment 120: The EPA agrees. The only fuel-related provision in the final rule is an option for liquid oil-fired units to demonstrate compliance with the acid gas standards by documenting that fuel moisture content remains no greater than 1.0%. This demonstration is based on monitoring results or fuel supplier certifications.

20. Miscellaneous.

Comment 121: Commenter 18025 requests clarification with respect to demonstrating compliance when using a new or changed blend of fuel that was not initially considered in compliance demonstrations. The commenter's understanding is that any time a unit burns a new fuel (type, mix, etc.), it has to be tested for relevant constituents (Hg, chlorine, etc.). The commenter states that if these are within the parameters established during initial compliance testing, the fuel may be used, and if not (for example, the chlorine is higher than established during initial testing), the unit must conduct new testing to demonstrate compliance before using the new fuel. The commenter would like confirmation that the proposed rule is flexible enough to accommodate shifts in fuel blends after 2015.

Response to Comment 121: The final rule has removed the requirements for operating and fuel limits with the exception of a PM CPMS.

Comment 122: Commenter 17821 states that in some cases the only viable option is to utilize stack testing. According to the commenter the use of total PM proposal using filterable PM as an operating limit and PM CEMS as a compliance option is flawed; the viability of HCl CEMS make this option unrealistic; and sources using dry sorbent or have older FGD may not be capable of maintaining SO_2 emissions below 0.2 lb/MMBtu.

Response to Comment 122: The agency disagrees with the commenter's suggestion that the use of PM CEMS as a compliance option is flawed. The final rule has been revised to use a filterable PM standard, with a PM CPMS option available to monitor continued performance and compliance with an operating limit established in terms of the raw output of the monitor. For sources unable to meet the SO_2 standard or use HCl CEMS, the frequency of required testing has been changed to quarterly.

Comment 123: Commenter 17808 recommends the use of Hg as a surrogate for Se and, thus, filterable PM alone may be a surrogate for other HAP metals. The commenter states that in the preamble, the EPA states that selenium is captured by controls for Hg and acid gases. In fact, states the commenter, commenter's initial correlation analysis indicates that selenium emissions are in fact better-correlated to Hg and acid gas emissions than CPM ($r=0.44$ for Hg or 0.60 for HCl, versus 0.32 for condensable PM ($r > 0.2$ implies significance at 5 percent level with 60 units)).

Response to Comment 123: The EPA has removed the requirement of total PM as an alternate equivalent standard for HAP metals. For more detailed discussion and response, please see section 4F01A.

Comment 124: Commenter 17808 recommends PM CEMS combined with a separate Se standard. Se emissions could be confirmed by quarterly or annual stack testing limited to Se. According to the commenter, similar to the treatment of limited use units, this requirement could be scaled such that units emitting Se well below the standard were subject to less stringent monitoring requirements than those units emitting very close to the standard. Alternatively, states the commenter, at a minimum, the commenter recommends that the EPA base the filterable PM limit on the facility-specific ratio to the total PM standard, rather than the initial numerical performance. Commenter also recommends that this facility-specific limit remain constant for a longer period of time, such as annually, to provide a measure of regulatory certainty.

Response to Comment 124: The final rule does not use a total PM standard as a surrogate for non-Hg HAP metals, but instead uses a filterable PM limit. The PM CEMS monitoring will in fact be a parameter monitor (PM CPMS) which is not intended to produce results in terms of the standard. These changes address the concerns at issue in this comment.

Comment 125: Comment 18428 ask for clarification as to whether the purpose of operating limits is to ensure compliance between performance tests.

Response to Comment 125: Yes. Operating limits are part of the compliance monitoring and assurance provisions in the rule. In the final rule, the only operating limits that apply are for a PM CPMS and, in certain situations, for liquid oil-fired units. See further discussion elsewhere in this document and in the final preamble.

Comment 126: Commenter 17655 recommends clarification of section 63.10005 that allows exemptions from the PM testing and testing for specific metals, but only for single fuels. According to the commenter, the rule should be clarified to allow similar provisions for units that co-fire (e.g., coal with natural gas). The commenter also notes that units testing for PM should not have to test for HAP metals because there is no HAP metals limit. The commenter believes testing for metals is simply an extension of the ICR.

Response to Comment 126: In response to comments, the final rule has removed all requirements for duplicative testing of a HAP and an alternate equivalent standard. Facilities complying with an alternate equivalent limit do not have to perform periodic testing for the corresponding HAP or vice versa.

Comment 127: Commenter 17655 encourages the EPA to consider opacity as an acceptable measure of PM. Contrary to manufacturers' claims, the commenter does not regard stack-mounted PM monitors to be sufficiently accurate, reliable, or durable to yield significantly more or better compliance data than opacity monitoring currently does. The commenter notes that PM monitoring is a direct measurement of PM, which is the limit for EGUs. The commenter states that although PM is itself a surrogate for non-Hg metals, it is the primary standard expressed in the regulation – compliance with specific metals limits would be regarded as an alternative compliance option rather than a primary option under this rule. According to the commenter, the surrogate continuous monitoring method for PM emissions has always been, and should continue to be, opacity measurement.

Response to Comment 127: The EPA disagrees that opacity would be considered accurate or sensitive to the concentration levels of PM required by the final rule.

Comment 128: Commenter 17730 states that they appreciate the EPA setting the performance testing requirements for all pollutants at the 5-year interval. The commenter believes that for sources that choose to use CEMS to demonstrate ongoing compliance with the standards, the performance testing requirements could be even further streamlined given that sources will be required to report electronically and that CEMS users will undergo annual certification via RATA.

Response to Comment 128: The final rule has been revised so sources electing to use CEMS for Hg, SO_2, or HCl will not be required to perform performance testing every 5 years.

Comment 129: Commenter 17761 states that if PM CEMS are required, the commenter recommends providing for an annual PM stack testing compliance alternative as the basis for determining compliance with the limits established under this rule. According to the commenter, an annual PM stack test is effective in determining compliance because operating units under existing CAM plans have prescribed methods to verify PM to include bag leak detection and opacity readings.

Response to Comment 129: The final rule requires quarterly performance testing or PM CPMS with annual performance testing.

Comment 130: Commenter 17775 states that the EPA's proposal contains nothing to indicate at what point a monitoring system is deemed "certified" and if the EPA were to attempt to define that point, sources likely would arbitrarily attempt to postpone some part of the required testing in order to control when the "performance test" begins. According to the commenter, the EPA should allow EGUs to complete required testing (or designate a CEMS that previously has completed the required testing") and to notify the Administrator of the date upon which its "performance test" will begin. The commenter states that this will ensure consistency between EGUs and allow EGUs to confirm that their controls are working properly, and that they are operating at an appropriate load and combusting appropriate fuel, before the "performance test" begins.

Response to Comment 130: That approach is allowed for under the final rule. The notification of intent will indicate the date for commencement of a performance test.

Comment 131: Commenter 17886 states that the EPA should not set unit "operating limits" based on performance measured during short term tests. According to the commenter, if the EPA retains the total PM requirement, one preferable option would be to ratio the performance test results to the MACT limit, and set the "operating limit" at the level that (based on the test results) would be equal to the MACT limit.

Response to Comment 131: The final rule does not maintain the total PM requirement.

Comment 132: Commenter 19120 requests clarification as to whether the EPA intends to require 1/5 year stack testing for all surrogates. For example, states the commenter, section 63.100005(d)(4) states that initial compliance for coal-fired EGUs with FGD technology using SO_2 CEMs is determined using the average hourly SO_2 concentrations obtained during the first 30-day operating period, and section 63.10005(d)(5) states the same for PM CEMS. However, notes the commenter, pages 423 and 425 of the preamble and section 63.1 0005(a) indicate that PM and metals and SO_2 and HCl testing includes testing initially and every 5 years; section 63.10005(a) states that "If you use a continuous monitoring system that measures a surrogate for a pollutant (e.g., an SO_2 monitor), you must perform initial emission testing during the same compliance test period and under the same process (e.g., fuel) and control device operating condition of the pollutant and surrogate, in addition to conducting the initial 30-day performance test." Additionally, states the commenter, section 63.10006(a) and (b) state, that PM and non-Hg metal HAP, and SO_2 and HCl emissions testing, respectively, is required at least every 5 years.

Response to Comment 132: In response to comments, the final rule has removed all requirements for testing of both the HAP and the corresponding surrogate(s). Facilities complying with a surrogate limit do not have to perform periodic testing for the corresponding HAP or vice versa.

Comment 133: Commenter 17785 states that the proposed rule requires fuel analysis monthly in order to assess continuous compliance. The commenter states that the portion of the draft rule that addresses this (section 63.10011) is unclear. According to the commenter, equation 13 of this section seems to suggest that the Hg concentration in a monthly sample must be less than the 90^{th} percentile concentration based on the Hg content measured during demonstration of initial compliance; equation 13 refers to the 90^{th} percentile of Hg concentration as calculated according to Equation 8, but the referenced Equation 8 calculates the *average* fuel Hg content, not the 90^{th} percentile. The commenter states that the EPA needs to clarify these equations so it is clear how they intend the 90^{th} percentile Hg concentration to be calculated.

Response to Comment 133: The fuel sampling and analysis requirements have been removed from the final rule.

Comment 134: Commenter 17696 states that if the EPA does not limit the rule to Hg, the EPA should provide additional flexibility in the emissions monitoring and compliance determination requirements. Commenter believes certain of the proposed requirements are unreasonable in light of available alternatives that are more cost-effective and provide sufficient assurance of continuous compliance. The commenter states that revisions are also needed concerning Hg monitoring and to make the compliance determination requirements clearer and easier to understand.

Response to Comment 134: The EPA believes that the final rule streamlines the continuous compliance monitoring requirements, and does so in a way that is clearer and easier to understand as requested by the commenter. The EPA disagrees with limiting the rule to Hg as explained in response to other comments concerning this issue.

5B01 - Recordkeeping/Reporting: Data reporting requirements

Commenters: 17402, 17655, 17677, 17681, 17772, 17821, 17881, 17902, 18023

1. Reporting requirements for deviations.

Comment 1: Commenter 17402 opposes the EPA's proposed definition of "deviation" and the EPA's reporting requirements for deviations. The commenter states that in the proposed rule, the EPA defines "deviation" to include (but the definition is not limited to) any failure to meet "any emission limit, operating limit, work practice standard, or monitoring requirement," or any failure to meet a term or condition to implement a related requirement included in an operating permit. The commenter states that should a deviation occur, the EPA proposes specific reporting requirements, that in the case of an exceedance of an emission limit during a malfunction, the owner or operator of the facility must notify the EPA within two business days to avail itself of an affirmative defense to civil penalties for the malfunction and submit a report of the malfunction within 45 days, and that all deviations must also be reported in the source's semiannual compliance report.

Comment 2: Commenters 17402 and 17902 state the EPA's proposed definition of "deviation" is overbroad and should not include operating limits. Commenter 17902 suggests that on-site records be maintained that document operating limit deviations, associated investigation and appropriate corrective action if deemed necessary. Commenter 17402 recommends that operating limits and monitoring requirements should not be a reportable deviation since they are indicators of compliance and not emission limitations. As an example, the commenter states that the EPA's proposal requires that for an ESP, the parameter operating limit is calculated by the total secondary power input as measured during the performance test. Commenter respectfully submits that operating parameter exceedances, such as this ESP power limitation or CEMS downtime (failed calibration error test, power outages, data acquisition and handling problems, etc.), are compliance indicators and, therefore, inappropriately categorized as deviations.

Comment 3: Commenter 17402 states a further reason to exclude operating limits from the definition of deviation is that these parameter operating limits do not account for variability due to normal operation in some cases. As an example, the commenter states that the requirement of a minimum pressure drop and liquid injection rate on a wet PM scrubber will result in the reporting of deviations during low-load operation. Similarly, according to the commenter, the requirement to maintain sorbent injection rate at the rate established during the compliance test might result in the unnecessary reporting of deviations when these units fire lower pollutant containing fuels. The commenter asserts that since these parameters do not take into account variability, it would be arbitrary and inefficient to characterize any exceedance of the operating limit (or failure to meet the operating limit in the case of a minimum operating limit) as a deviation.

Comment 4: Commenter 17402 further urges the EPA to reconsider its proposed reporting requirements for deviations. Specifically, commenter opposes the EPA's proposal to require the owner or operator of the facility to notify the EPA of an exceedance of an emission limit during a malfunction within two business days to avail itself of an affirmative defense to civil penalties for the malfunction. Commenter submits that such a requirement is excessive and recommends that if the EPA requires a notification for exceedances of an emission limit during malfunctions, it should be in semiannual compliance reports.

Comment 5: Commenter 17881 states that in regard to requirements for reporting monitor downtime deviations in section 63.10031(e)(5), the commenter asks that the rule needs to specify how the calculations for these deviations should be conducted. The commenter notes that calculations could be based on the number of block averages in the reporting period, total operating time during the block period associated with the deviation, etc.

Response to Comments 1 - 5: The EPA believes the rule was accurate as proposed in delineating what is a deviation. Under most MACT standards, a deviation includes any failure to meet an emission limit, work practice requirement, operating limit, or monitoring requirement. The final rule does not alter this approach. Deviations are reported in semiannual compliance reports. The compliance reports require the information in the General Provisions 63.10(e) section and some additional source specific information which is typical of reporting. In addition, for malfunctions, additional notification requirements apply. The EPA is revising the affirmative defense related malfunction notification requirement so that it reads "The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall 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 whether 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, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction."

2. Reporting requirements for malfunctions.

Comment 6: Commenter 17681 states that section 63.10001(iii)(9) of the proposal appears to require notification to the EPA Administrator of a malfunction within two business days of the event if the malfunction may cause an exceedance of the 30-day average. According to the commenter, facilities may not be aware that the malfunction will cause an exceedance of the 30-day average until more than two days have passed. The commenter states that the reporting time should be at least as long as the averaging time, which in this case is 30 days. In addition, the commenter questions whether facilities may report to their local compliance office if the state is delegated under the CAA instead of reporting to the EPA Administrator.

Commenter 17681 states this section (63.10001(iii)(9)) also requires a calculation of emissions during the malfunction. The commenter questions whether this calculation has to be prepared and sealed by a professional engineer.

Response to Comment 6: The EPA is revising the affirmative defense related malfunction notification requirement so that it reads "The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall 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 whether 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, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction." With respect to reporting to delegated state agencies, that would occur in accordance with delegation of this subpart, if applicable. With respect to preparation and signature by a professional engineer, the answer is no. The rule plainly states: "The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction."

3. Quarterly reporting of hourly data.

Comment 7: Commenter 18023 believes the quarterly submittal of electronic hourly data is inappropriate for an emission limit-oriented rule, is highly burdensome on the emission source operator, and should be removed from the proposed rule requirements. Commenter states that section 7.2.5, Quarterly Reports, is written to reflect the quarterly submittal of electronic hourly data that is appropriate for a trading program-related rule, most likely because these requirements were copied out of the vacated CAMR rule.

Comment 8: Commenter 17655 agrees that hourly data records are unnecessary for demonstrating compliance. Commenter states that in evaluating the cost of hourly reporting, the EPA consulted with DAHS vendors and was told that the cost of collecting hourly data would be minimal. However, commenter believes the agency failed to consult with users to ascertain the time requirements and costs for reviewing hourly data, as opposed to records compressed to daily, weekly, or even monthly averages. Commenter submits that there is no need for hourly data, as there are no hourly compliance standards. Further, ECMPS could be easily adapted by the EPA to accommodate records in other than hourly increments (daily or monthly). According to the commenter, this would provide considerable savings to the industry and would not impact compliance or public health in any way.

Comment 9: Commenter 17772 states that the EPA should modify the requirements for submitting extensive new continuous data sets for compliance purposes. According to the commenter, the approach taken in the proposed rule may be appropriate for an allowance trading program where there is a market function that is facilitated by the collection and public posting of emissions data. The commenter asserts that that approach is unnecessary and unduly burdensome in the context of a regulatory regime where the focus is on demonstrating technology compliance.

Commenter 17772 states that in an age of electronic recordkeeping, there is a natural tendency to ask for "all the data that is available." According to the commenter, however, in industrial America and in the utility sector, routine reporting of massive amounts of hourly data to the EPA is an unwarranted use of manpower for both the transmitters and recipients, not to mention bandwidth and storage considerations.

Commenter 17772 states that the industry has grown accustomed to electronic data reporting in SO_2 and NO_X trading programs. According to the commenter, in such a program, where there is a national market in allowances, a case can be made for submitting hourly data on a quarterly basis so that it can be posted on a national website. The commenter states that this creates a transparent database for economic decisions and trading.

Commenter 17772 states that demonstrating that a facility has installed MACT level controls and is operating that equipment appropriately is an entirely different type of regulatory approach and the reporting requirements should be consistent with that regulatory approach. The commenter requests that the EPA modify its approach as follows: (1) The related limits will be specified in the Title V permit. (2) The responsible entity is required to certify each year as to full compliance or intermittent compliance. (3) Records should be kept and made available as necessary to the EPA. (4) Exception reporting should be performed quarterly.

Commenter 17772 states that this recommendation is a proven approach used by the EPA for other industries and in other contexts and there is no need for EGU compliant facilities to transmit massive MACT-related databases to the EPA every quarter.

Commenter 17772 states that this proposal is consistent with past EPA MACT requirements imposed on other industries. According to the commenter, for example, the MACT program applied to the steel industry does not require multiple CEMS and quarterly reporting of all hourly data; that would be unwarranted and unwieldy. The commenter states that the same can be said about the pulp and paper industries, etc., and that the utility sector should be treated similarly - exception reporting, but not massive transfers of compliant hourly data. According to the commenter, it is arbitrary and capricious to single out the utility industry for a level of MACT reporting that is far in excess of other important U.S. industries.

Response to Comments 7 - 9: The EPA has retained in the final rule that CEMS data be provided on an hourly basis. We believe this approach simplifies compliance with the rule by harmonizing its monitoring and reporting requirements, to the extent possible, with those of 40 CFR Part 75. With a few exceptions, the utility industry is already required to monitor and report hourly emissions data according to Part 75 under the title IV ARP and other emissions trading programs. The Hg monitoring requirements are consistent with Part 75 and similar to those that had been promulgated for the vacated CAMR regulation. Integrating Hg emissions data and QA test results into the existing Part 75 – compliant DAHS that is installed at the vast majority of the coal-fired EGUs is an appropriate approach for addressing submission of emissions and QA data under this rule. We obtained feedback from several DAHS vendors indicating that the cost of modifying the existing Part 75 DAHS systems to accommodate hourly reporting of Hg CEMS and sorbent trap data would be similar, and in some cases, less than the cost of the first proposed option. Also, there is little or no cost to industry for the flow rate, CO_2, or O_2, and moisture monitors needed to convert Hg concentration to the units of the standard, because, as previously noted, almost all of the EGUs already have these monitors and the associated reporting mechanisms in place. In view of these considerations, we have decided in favor of this second option for Hg.

Requiring the reporting of hourly Hg emissions data from EGUs is advantageous, both to the EPA and industry. The DAHS can be automated to demonstrate compliance with the standard on a continuous basis. The data can then be submitted to the agency electronically, thereby eliminating the need for the agency to request additional information for compliance determinations and program implementation. The rule also requires quarterly electronic reporting of hourly SO_2 CEMS data and HCl CEMS data (for sources electing to demonstrate continuous compliance using those certified CEMS). Those are included for the same reasons as the Hg monitoring data.

The comments seem to assume that the costs for adding new parameters to the system would be directly proportional to the number of parameters collected. This neglects to recognize that the ECMPS and DAHS frameworks do not need to be re-engineered if the new data requirements are adopted in a manner that harmonizes requirements. Also, reducing the computer output to daily or monthly values does not necessarily save the user any significant (if any) effort. In fact, it may cost the source more effort or cause them to miss data problems that in the end may affect their compliance determination. Once data collection is automated (and given that the industry and the EPA has already invested in the automation process that is ECMPS) the burden on the operator is minimized. The systems can (and have) been programmed to do data analysis and QA evaluations automatically, giving a user a report of hours that might be in question. The environmental managers at facilities can, and have, designed custom checks into their systems to streamline their data reporting responsibilities. These advantages need to be recognized when evaluating the electronic reporting option as a means for data QA.

4. Recordkeeping requirements for liquid oil-fired units.

Comment 10: Commenter 18023 states that the recordkeeping requirements for liquid oil-fired units are unreasonable. The commenter states that the EPA requires "for each 30 boiler operating day period . . . a description of the fuel, the total fuel usage amounts and units of measure, and information on the supplier and original source of the fuel" (76 FR 25035). According to the commenter, other than total usage amounts, these records are, and should be, kept by shipment and if all shipments are in compliance, additional information is unnecessary. The commenter asserts that it is not possible to collect this information in the format requested by the EPA – fuel cannot be separated on a per-shipper basis after it has been put into a storage tank – but only by shipment and that to avoid the burden of having to convert shipment-based data into operating-day data, the EPA should base any recordkeeping requirement on shipment data.

Response to Comment 10: With the changes in the final rule that eliminate the fuel analysis requirements, this comment is largely moot. The only fuel data that must be retained is a record of fuel use by operating hour, in order to determine if the EGU meets the low use exemption. Also, if a source opts to monitor fuel moisture in each fuel shipment for a liquid fuel unit and demonstrates that this alternative monitoring is acceptable under the part 63 general provisions (in lieu of other monitoring for acid gases), then the source must keep records of the fuel moisture of each fuel shipment.

5. Semi-annual compliance dates.

Comment 11: Commenter 17681 states that section 63.10031(b)(2) of the proposed rule appears to require semi-annual reports on January 31 and July 31 and that the beginning of the year is very busy with reports required to state and federal agencies. The commenter states that the EPA should push these dates back to March 1 and September 1 respectively. For the same reasons, commenter 17821 requests that the EPA should allow sources at least 60 days to submit reports, and the EPA should allow local permitting agencies the flexibility to grant sources 60 days to file their semi-annual reports.

Response to Comment 11: The semiannual compliance dates are consistent with other EPA reporting requirements and are necessary to ensure timely reporting and allow any identified issues to be addressed in a timely manner. These dates do not apply to the quarterly reporting to ECMPS of CEMS data.

6. Annual documentation.

Comment 12: Commenter 17677 states that the regulation includes documentation for an annual report on emission tests, inspection, repairs, adjustments, findings and corrective actions. Commenter believes this additional documentation burden seems to do nothing more than increase non-productive work load for our personnel.

Comment 13: Commenter 17681 also notes that section 63.10031(c)(5) of the proposed rule appears to require a summary of the annual performance tests in the compliance report which is submitted to the EPA. If the testing data is reported electronically to the EPA within 60 days after each test through CDX, why does the EPA need this data sent to them again?

Response to Comments 12 - 13: The final rule contains compliance and deviation reporting requirements that are typical of most NESHAP. These summary reports are in addition to the detailed performance test results reported electronically and will be used by the permitting authority for effective compliance oversight.

7. Other data reporting requirements.

Comment 14: Commenter 17881 states that the requirement in section 63.10031(c)(4) to report monthly fuel use is not relevant, as it is the fuel type and heat input fraction that matters in determining compliance. The commenter suggests that the section 63.10032(d)(1) requirement to maintain such records should be deleted, or at a minimum, revised to require records of the types of fuel which are burned and the maximum percentage or fraction of each fuel type (on a heat input basis).

Comment 15: Commenter 17881 states that the waste determination information should only be required if a new fuel type is introduced following the initial compliance demonstration report.

Response to Comments 14-15: Apart from those EGU owners or operators who choose to use emissions averaging, monthly fuel use information need not be reported given the changes in the final rule, although records of fuel use by operating hour must be maintained, as noted above. Moreover, EGU owners or operators who self-determine or have the EPA determine via petition that their fuel is a non-waste under 40 CFR 241.3 or who combust fuel processed from discarded non-hazardous secondary materials have additional emissions testing, notification, reporting, and recordkeeping requirements as discussed in the rule.

5B02 - Recordkeeping/Reporting: Records that must be retained

Commenters: 17681, 17775, 17881

1. Objection to retaining records on-site.

Comment 1: Commenter 17681 states that section 63.10033(c) of the proposed rule appears to require that records be kept on site. Commenter believes it is much better to keep records electronically or at least not congregated at each site and if the EPA wants a copy, the facility can produce a copy within a reasonable time.

2. Objection to requirement to retain records for five years.

Comment 2: Commenter 17775 states that the EPA proposes to require retention of all data, including reports, records of measurements, maintenance, corrective action, and "other information," for 5 years. (Proposed section 63.10033 and Appendix A section 7.1.) Commenter objects to these requirements. To mandate a retention period longer than 3 years, the EPA must justify the requirement under the PRA. See 5 CFR section 1320.5(d)(2)(iv) (requiring a showing of substantial need or statutory mandate to require retention of records for more than 3 years). The commenter states that the EPA's statement in the supporting statement for the February 2011 proposed ICR291 that "None of the guidelines in 5 CFR 1320.5 are being exceeded," is simply false. The EPA-HQ-OAR-2009-0234-3031 at 4.

Response to Comments 1 - 2: The agency believes the record keeping and retention requirements are consistent with other requirements already in place, specifically 40 CFR part 63.10 (b) "*General recordkeeping requirements.* (1) The owner or operator of an affected source subject to the provisions of this part shall maintain files of all information (including all reports and notifications) required by this part recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche." In addition, the 5-year retention period is the general rule for all recordkeeping for all sources under the part 70 operating permits program. Given that the general provisions for part 63 and part 70 already establish a 5-year retention period, the EPA believes it is justified in using those precedents for the retention periods under this subpart. If the EPA stayed silent on retention period in this subpart, the general provisions would provide for the 5-year retention as would the part 70 requirements. Thus, this action does not establish any new retention requirements, but merely confirms that the existing retention requirements apply.

3. Objection to requirement to maintain mercury mass emission records.

Comment 3: Commenter 17881 states that section 7.1.8 requires Hg mass emission records for those units complying with the Hg lb/GWh emission limit. According to the commenter, this section is based on the misguided premise that the Hg mass emissions, as pounds per clock hour, are required in order to perform the lb/GWh Hg emission rate calculations. The commenter states that as noted in relation to section 6.2.2, only the Hg emission rates, as lb/hr, and average electrical generating rate, as MW, are needed in order to calculate the lb/GWh emission rate. Thus, according to the commenter, this section should be re-written on a Hg mass emission rate versus integrated mass emissions basis.

Response to Comment 3: The EPA has retained the language as is, given the formulas that are used for determining lb/GWh.

5B03 - Recordkeeping/Reporting: Electronic reporting of CEMS data

Commenters: 17715, 17716, 17725, 17730, 17740, 17775, 17795, 17796, 17800, 17805, 17820, 17821, 17873, 17877, 17886, 17909, 18014, 18039, 18449, 18498, 18831, 19114, 19121, 19122, 19679

1. ECMPS reporting.

a. Support for ECMPS reporting.

Comment 1: Commenters (17715, 17740, 17796, 17805, 17877, 17909, 18039, 18449, 19122) support using ECMPS.

Comment 2: Commenter 17796 believes all CEMS collected data should be required to be submitted to a modified ECMPS so this data can be assembled in one area which can be accessed by all users.

Comment 3: Commenters 17805 and 19122 also agree that ECMPS could be used for submittal of compliance data as required in the proposed rule. The commenters note that his system is currently used successfully to report Acid Rain Program emissions from utility units.

Comment 4: Several commenters (17740, 17873, 18039, 18449, 18831) support the EPA's proposal to handle reporting for PM, HCl, and Hg through ECMPS. According to the commenters, the ECMPS system simplifies the reporting process by evaluating continuous monitoring data and other information in an electronic format in preparation for submittal to the agency. The commenters note that ECMPS is used by Part 75 and emissions trading programs and is a well-established data reporting tool.

Comment 5: Several commenters (17715, 17877, 19114) state that ECMPS is currently being used successfully by industry and the infrastructure is already in place, thereby reducing costs. According to the commenters, industry personnel have been trained for the constituents that are already being reported by ECMPS so the learning curve will be very short and will allow a rather seamless transition to HAP reporting. One commenter proposes that the EPA take advantage of the work that has already been done for the ECMPS process by extending it to the HAP rule.

Comment 6: Commenter 19121 recommends that ongoing monitoring data collected under the requirements of NESHAP be reported into the ECMPS system. Commenter recommends that episodic data, such as performance and stack testing be reported using the ERT.

b. Support for ECMPS reporting, but with supplemental rulemaking and public comment.

Comment 7: Commenters 17715 and 19114 state that the EPA should use ECMPS for all reporting. Commenters state that reporting associated with the proposed rule should be handled by ECMPS, but should be the subject of a supplemental rulemaking in order to fully address all of the software issues that arise with electronic reporting. According to the commenters, the EPA should invite industry involvement as was used during the initial development process of ECMPS. The commenters note that utility involvement during development will enable a smooth transition in dealing with the numerous monitoring requirements that will impact every EGU stack at the same time.

Comment 8: Commenter 17730 supports the use of ECMPS for the reporting of data and summary reports as a part of the EGU MACT proposed rule but believes that if the EPA wants to require the use of ECMPS, the EPA will need to publish for public comment (1) additional reporting provisions to cover information to be reported for SO_2 CEMS, PM CEMS, HCl CEMS, and any other test or parameter the EPA intends to include; and (2) its reporting formats and instructions for all data to be reported. Commenter states that the EPA has not published reporting requirements in sufficient detail for any parameter other than Hg. According to the commenter, although the EPA previously developed a reporting format for Hg, that format was developed to meet reporting requirements under the now-vacated CAMR. Commenter states that the EPA cannot use a reporting format to specify substantive reporting requirements but that the rule must identify each piece of information to be reported. Commenter adds that the EPA must submit its desired format and instructions to an open public comment process so that the regulated community and members of the public can confirm that the EPA is not attempting to use the format to create new, or alter existing reporting requirements.

Comment 9: Commenter 17800 states that should the EPA require use of ECMPS, the EPA would at a minimum need to publish for comment (1) additional reporting provisions to cover information to be reported for SO_2 CEMS, PM CEMS, HCL CEMS and any other test or parameter the EPA intends to include, and (2) its reporting formats and instructions for all data to be reported.

Comment 10: Commenters 17775 and 17800 in disagreeing with the reporting format requirements in Appendix A, note that the EPA is obliged to subject that format to notice and comment rulemaking and review by OMB. According to the commenters, the EPA electronic reporting formats specified to date by the Administrator have been sufficiently complex and substantive that it is not appropriate to totally exempt them from rulemaking. The commenters state that as implemented, the EPA's electronic formats are substantive requirements that impose significant burdens and impact on EGU's compliance status. The commenters state that to the extent some flexibility is needed to make adjustments to the format, that flexibility can be provided by rule.

Comment 11: Commenter 19114 recommends that the EPA invite industry involvement as was used during the initial development process of ECMPS, to enable a smooth transition in dealing with the numerous monitoring requirements that will impact every coal- or oil-fired EGU stack as a result of the EGU-MACT proposal. According to the commenter, the EPA should develop the tool, then propose its use in a separate rulemaking. The commenter states that numerous times industry has been stuck with software implementations that are not ready and that issues with software should be handled in advance of it being required for compliance with a rulemaking.

c. Opposition to ECMPS reporting.

Comment 12: Multiple commenters (17716, 17725, 17795, 17820, 17821, 17886, 18014, 18498) state that reporting hourly CEMS data electronically should not be required. The commenters state that the EPA proposes to require quarterly reporting of hourly emissions data as well as results of all required certifications and QA tests through the CAMD ECMPS software and that summaries of the emissions test results and semiannual deviation reports would also be required for SO_2 CEMS, PM CEMS, and HCl CEMS. The commenters believe there is no need for this requirement; the hardcopy deviation reports and data assessment reports are adequate and consistent with the requirements of other MACT and NSPS compliance rules.

Comment 13: Multiple commenters (17716, 17725, 17775, 17795, 17820, 18014, 18498) state the EPA has not justified the burden of requiring the ECMPS reporting. Several commenters (17716, 17725, 17775, 17820, 18014, 18498) state that the data reporting requirements in Appendix A for Hg go far beyond what is necessary for this rule. The commenters state that the EPA portrays this proposed reporting requirement as easy – that sources would "simply integrate Hg emissions data and QA test results into the existing Part 75-compliant DAHS," under one of two options. One commenter states that after presenting these two options, the EPA states that it obtained "feedback from several DAHS vendors" who suggested the cost of the second option was "similar, and some cases, less than the cost of the first option." According to the commenter, any software under Option 2 would have to provide the same information required by Option 1; The commenter states that sources would likely integrate the new requirements within the DAHS that they currently use for Part 60 and Part 75 reporting, but this does not mean that the proposed reporting scheme would be simple or cheap to implement. According to the commenters, adding the requirement to report hourly emissions data and other QA/QC data would be burdensome both to utilities as well as the EPA, especially given differences between Part 75 and MACT reporting (such as bias adjustment factors and missing data substitution). The commenters assert that CMPS was developed for emissions trading purposes, not for demonstrating continuous compliance with emission limits. The commenters conclude that reporting information via ECMPS under this rule would be a costly exercise that is both unnecessary and unjustified.

Commenter 19679 asks for clarification on whether the Hg CEMS data to be integrated into the Part 75 compliance DAHS will be subject to the on-going QA requirement of Part 75 or if it would be subject to the QA requirements of Part 60 Appendix F and PS-12A as is indicated for the "first option". According to the commenter, specifically relevant to this distinction is the requirement listed in Part 75, appendix A section 7.6.5 to apply a bias adjustment factor to CEMS data as part of a RATA. The commenter states that due to the low Hg concentrations present in a well controlled coal fired utility boiler stack, without the requirement for a bias adjustment factor the low emitter exemption of Part 60, PS-12A section 13.3 could allow a Hg CEMS to pass the required RATA while under reporting emissions relative to the emission standard.

Comment 14: Commenters 17775 and 17795 object to the EPA's proposal to submit hourly Hg data. Commenter 17775 states that the EPA has not justified or prepared an ICR for the proposed requirements for quarterly reporting of hourly Hg emissions data. The commenter disagrees with the EPA's assumptions regarding hourly Hg data and QA reporting.

Comment 15: Commenter 17775 states that the EPA could develop an electronic reporting scheme as an alternative to ECMPS or ERT that might more easily accommodate the kinds of information the EPA seeks to collect. According to the commenter, whatever scheme the EPA uses, it still would need to be supported by a rule, and new ICR, that identifies each piece of information to be reported and a format that has been subject to review and comment. The commenter notes that the supporting statement for the February 2011 proposed ICR for the proposed rule does not mention reporting of hourly Hg emissions data, or of the QA and certification data for Hg monitoring systems. The commenter states that the proposed ICR also makes no mention of the EPA's development and maintenance of schema and software for collection or review of those data, or an accounting of their costs. According to the commenter, if the EPA were to move forward with a requirement to report other information using ECMPS, the EPA would need to issue a rulemaking proposal and ICR that identifies (similar to Appendix A) each piece of information required to be reported, and the specific format for that submission and would need to provide a justification for requiring reporting of that information.

Commenter 17775 objects to the EPA's proposal to submit hourly Hg data. The commenter states that the EPA has not justified or prepared an ICR for the proposed requirements for quarterly reporting of hourly Hg emissions data.

Commenter 17775 states that Part 75 reporting is unsuitable for the reporting proposed under Appendix A and the revisions required to the EPA's and EGU's software to implement the reporting proposed under Appendix A would be significant and costly.

Commenter 17775 states that in addition to the compliance report, deviation report, performance tests and monitoring system performance evaluations, the EPA proposes to require quarterly reporting of hourly Hg data (e.g., emissions, certification and QA, and monitoring plan data) using the EPA's ECMPS. According to the commenter, although the proposed rule does not mention ECMPS, Appendix A includes detailed recordkeeping requirements similar to what had been included in CAMR, and requires quarterly electronic reporting of much of that information "in a format specified by the Administrator." Commenter 17775 states that all of the information needed to determine an EGU's compliance status already must be reported under the part 63 general provisions. The commenter finds these additional requirements to be redundant and burdensome. If the EPA requires additional detail, the EPA should provide that additional detail in proposed section 63.10031 and, if the provisions overlap, make clear that the more detailed requirements are in lieu of the more general requirements.

Commenter 17775 states that in the EPA's discussion of modifications to ECMPS, the EPA suggests that ECMPS also could be modified to allow electronic submission of "30-day averages of parametric data, 30-day average fuel content data, stack test results, and performance of tune up records." The commenter notes that the EPA's proposed rule does not contain any requirements to record, let alone report, 30-day averages of parameter and fuel data.

Commenter 17886 states that the EPA needs to define what constitutes a valid 30-day rolling average, suggesting that the EPA should use a specific number of hours (i.e., 540 hrs or 75 percent of the month) in that period to qualify it for a valid period.

Commenter 17775 disagrees with the EPA's proposal for data reporting in Appendix A. The commenter observes that the EPA has not required hourly data reporting or the sorts of QA data identified in Appendix A in a MACT, and this information is not necessary for sources or the EPA to determine compliance with MACT standards. The commenter states that this information does not enhance the quality of MACT compliance demonstrations.

Commenter 17775 objects to the EPA's requirement in Appendix A to require submission of Hg monitoring information in quarterly reports to the Administrator "in a format specified by the Administrator." The commenter notes that the commenter has challenged similar provisions for use in other programs judicially. The commenter's objections are: (1) concerns regarding the nature and content of the EPA's format, which the agency has changed with some frequency and at significant expense to EGUs, (2) the EPA-provided software's failure to ensure compliance with the CROMERR requirements at 40 CFR part 3.10, (3) inconsistencies between the reporting format and the substantive provisions of the applicable rule, and (4) the lack of appropriate procedures for submitting reports when a source is unable to gain access to the EPA's computer with the EPA provided software, or connect to the internet in a secure environment.

Comment 16: Commenter 17909 does not support collection of continuous Hg or particulate data. According to the commenter, the EPA's authority under this section of the CAA is for exception reporting only.

2. Data reporting formats.

Comment 17: Commenter 17725 asks that the EPA consider a single format for reporting data. The commenter states that for each set of monitoring and reporting requirements, reporting entities must purchase monitors and data acquisition handling systems. According to the commenter, these systems must be connected to other plant data monitoring systems and integrated into a single report. The quantity of data for EGUs can be staggering. The commenter encourages the EPA to employ like data collection and transfer systems for multiple programs so that this expensive system can be used for each program, especially since much of the data is the same. The commenter states that the utility industry has worked with the CAMD for the last 17 years to devise a comprehensive schema that is flexible and is relatively easy to maintain. The commenter recommends that this program and others continue to use ECMPS or devise a way to import data between programs.

Commenter 17725 suggests that the EPA use ECMPS reporting for the following data elements:

1. Monitoring Plan Data for PM CEMS, HCl/HF CEMS, Continuous Hg Monitoring Systems, and Sorbent Trap Monitoring Systems similar to what is currently being collected for COMS.

2. Monitoring Plan Data for Auxiliary Boilers present at facilities currently reporting in ECMPS required under the Industrial Boiler MACT rules.

3. Certification Test Results for PM CEMS:
   a. PS-11 Initial Correlation Audit Results
   b. PS-11 Absolute Correlation Audit Results
   c. PS-11 Annual Relative Response Audit Results
   d. PS-11 Response Correlation Audit Results
   e. Initial Certification 7-Day Drift Test Results

4. Certification Results for Continuous Hg Monitoring Systems:
   a. Initial Certification Cycle/Response Time, 7-Day Drift, 3-point Linearity Check, and RATA test results
   b. NIST Traceability Test Results
   c. Annual RATA testing results
   d. Weekly System Integrity Check results

5. Certification Results for Sorbent Trap Monitoring Systems:
   a. Initial and Annual RATA test results

6. Certification Results for HCl/HF CEMS:
   a. Initial Certification Cycle/Response Time, 7-Day Drift, 3-point Linearity Check, and RATA test results
   b. Required ongoing quarterly and annual ongoing QA Tests for HCl/HF CEMS

Commenter 17725 does not support routine hard copy submittals of Monitoring Plan records as listed in Appendix A to subpart UUUUU section 7.1.1.2.2 and wishes to maintain an onsite file at each facility that can be made available for inspection by the EPA and state auditors and inspectors.

Response to Comments 1 - 17: We recognize that emissions reporting for continuously measured pollutants (SO_2, Hg, etc.) and for periodically measured pollutants (PM, non-Hg HAP metals, etc.) have different data demands. We recognize that minor revisions of the ECMPS will fulfill our data needs for continuously measured pollutants and we will make these minor modifications for receipt of the additional data demands. We also recognize the need for substantial modifications to the ECMPS to accommodate the data needs for periodically measured pollutants. Although major modifications of the ECMPS would be required for periodic compliance tests by isokinetic and instrumental test methods, minor revisions are required of the ERT to receive these tests. We are implementing the changes in the ERT that are required to provide the software tools to implement the delivery of these performance test data to us.

The electronic submission of compliance test reports to us through the Central Data Exchange (CDX) is not solely for the purpose of developing improved emissions factors as some commenters assert. Although populating WebFIRE will allow us to improve emissions factors, we intend to use data stored in WebFIRE as the primary location for compliance test reports for use by regulatory authorities. The electronic submission of compliance test reports is a continuation of our efforts to bring the submission and sharing of environmental data into the modern age. The storage of this compliance data in our WebFIRE provides a convenient location which is already used to store source test data.

As our and State and local agencies data systems mature, information provided through the ERT will be used to populate these data systems. We are currently upgrading the AIRS Facility System and expect to replace manually entered information with electronic population from the ERT. We are also working with several State and local agencies to adopt the use of the ERT for delivery of compliance test reports. The ERT is also much improved since the version used during the 2010 ICR process, and there is no expectation that the information to be reported under this final rule will be as extensive as some of the data reported for the 2010 ICR purposes.

We disagree that a separate and independent regulatory action is required to implement electronic reporting for selected regulated sources. Each of these regulatory actions for selected source categories provides ample notice and the opportunity for individuals to provide comment. We also disagree that the system to receive the compliance data must be operational prior to establishing the requirement for regulated sources to submit compliance data electronically. We are on track to have the capability to receive electronic compliance tests through our CDX in sufficient time to receive all utility source test reports required by this final rule.

We do plan a separate and independent regulatory action to implement electronic reporting for regulated entities which are covered by past and future rules. Although we have provided draft procedures for the development of emissions factors, that effort is an ancillary effort to the electronic delivery of compliance test reports. It is our intention to convert to the electronic delivery and storage of all air emissions compliance source test data. With this transition, we believe this valuable information will be more readily available not only for compliance purposes but also for a variety of other uses.

3. Other CEMS reporting comments.

Comment 18: Commenter 18014 notes that the proposed EGU MACT Rule does not include provisions to use the part 75 “conditionally valid data procedures.” According to the commenter, this would require the operator to invalidate the part 75 conditionally valid data (for SO_2, CO_2, O_2 or flow monitors) for the EGU MACT recordkeeping and reporting purposes. The commenter states that a clearer approach would be to allow quality-assured data from a CEMS certified and operated in accordance to part 75 to be used for EGU MACT compliance (with the exception of bias adjusted and missing data).

Response to Comment 18: The final rule provides for certain part 75 procedures for the CEMS and sorbent trap monitoring systems used to comply with this rule, including the use of the conditionally valid data procedures.

Comment 19: Commenter 18449 questions why either CO_2, O_2 or stack moisture monitors are required to calculate mass emissions for any pollutant. According to the commenter, reporting pollutant concentrations on a dry or diluent basis may have been appropriate a generation ago, when point of impingement calculations required stack output concentrations but for several decades, it has been clear that the total mass emitted of each pollutant is what drives the environmental effects. The commenter states that only the wet concentration and wet stack flow is required to accurately calculate the mass emission rate of any pollutant and that adding confounding factors such as O_2, CO_2 or stack moisture will only increase periods of missing data and reduce the accuracy of the reported results.

Commenter 18449 states that further input of plant heat rate or electrical output being produced is all that is required to calculate the EPA's proposed emissions in lb/TBtu or lb/GWh. According to the commenter, a CO_2 analyzer may be required for heat input, but this is a separate issue, independent of any individual pollutant CEMS. The commenter states that the EPA should clearly differentiate the performance requirements for each pollutant monitor from the requirements of the additional variables required to calculate the proposed emissions limits.

Response to Comment 19: The final rule retains these requirements, consistent with the general approach to monitoring for this sector under part 75.

Comment 20: Commenter 18831 supports the ability to use alternatives to CEMS. The commenter states that sources should be allowed to select CEMS, but alternatives such as stack testing should be retained and CAM provisions developed.

Response to Comment 20: The final rule provides some alternatives, primarily CEMS or periodic stack testing (and a PM CPMS option). We do not believe developing CAM-like provisions under this rule is warranted as those requirements would likely be duplicative of existing control device and similar monitoring that already applies to these sources under other programs.

5B04 - Recordkeeping/Reporting: Electronic reporting of emissions test data

Commenters: 17316, 17621, 17638, 17681, 17718, 17719, 17725, 17730, 17767, 17770, 17775, 17790, 17795, 17816, 17820, 17821, 17868, 17881, 18014, 18498, 19033, 18023

1. ECMPS reporting of emissions test data.

a. Support for using a modified version of ECMPS.

Comment 1: Several commenters (17638, 17681, 18023) state that the EPA should use a modified version of ECMPS rather than the ERT to submit performance test results. The commenter states that the EPA's proposed rule requires that performance test results be reported electronically to WebFIRE and suggests using ERT software to do this and that the EPA has requested feedback on using a modified version of ECMPS for this purpose. Based on problems encountered by the industry in submitting ICR data using the ERT software, commenters suggest it would be better to use a modified version of ECMPS rather than ERT but that revisions to the ECMPS are necessary. According to the commenters, without revision, it may be difficult to use the ECMPS for this purpose because that system was developed to support a trading system and not an emission limit based rule.

Comment 2: Commenter 17316 also supports the idea of using a modified ECMPS program to report MACT test and RATA data in lieu of ERT reporting. The commenter states that as pointed out in the preamble to this rule, electric utilities are subject to the Acid Rain Program and are familiar with ECMPS reporting, which should facilitate the transition to MACT reporting and that SO_2 RATA data is already reported in ECMPS, so this approach would avoid some duplication.

Commenter 17316 adds that using a modified ECMPS for MACT reporting could also help promote the development of an information system that allows ready interchange of data between the various programs (Part 75 ECMPS and Part 60/63 NSPS/MACT ERT), serving as a sort of bridge effort. According to the commenter, if this approach were adopted, the companion NSPS (subparts Da and Db) regulations should also allow use of ECMPS reporting, as an alternative to ERT, otherwise for utility units subject to NSPS, the potential consolidation benefits of reporting MACT data in ECMPS would be lost.

b. Opposition to using a modified version of ECMPS.

Comment 3: Commenter 17767 states that the ECMPS option would be overly burdensome as their experience with it has shown it to be increasingly obsessed with minor data formatting issues that often prevent the submission of data (though it might have been acceptably formatted and submitted without issue in the past). According to commenter, it often involves many hours of manpower to correct those issues without benefit to the quality of the key data sets or the environment. Commenter anticipates that this would continue if MACT rule data were to be submitted via ECMPS

Response to Comments 1 - 3: The EPA disagrees with the commenters who feel that using the ECMPS data collection process is overly burdensome and in the assertion that minor data formatting issues often prevent the submission of data. The assertion points to the fact that many data reporting errors may not have been previously caught in the past. The EPA created the ECMPS process to replace its previous less efficient and less precise data verification systems and processes. The result of this re-engineering is that there are significantly fewer formatting issues that prevent submissions, and a fraction of submissions that contain critical errors at the close of each reporting period. This has added significantly to the EPA's ability to validate adherence to regulatory requirements, as well as, checking for the technical accuracy of the data. The EPA has received considerable support from the regulatory community for the revised ECMPS process, praising its efficiency and the reduction in man hours required to report (and when necessary correct errors) using the ECMPS process as compared to the old record type column format and ETS/MDC processes that preceded ECMPS. However, the EPA recognizes that emissions reporting for continuously measured pollutants (SO_2, Hg, etc.) from CEMS is structurally and procedurally different from what is needed to electronically collect reference method test data for periodically measured pollutants (PM, non-Hg HAP metals etc.). Therefore, the EPA has decided not to include detailed stack test data into ECMPS, rather will focus on only making minor revisions to ECMPS necessary to implement the EPA's MACT data needs for continuously measured pollutants in a manner consistent with how other CEMS monitoring requirements are currently implemented through the ECMPS process. Doing so will minimize the structural changes to ECMPS needed while harmonizing the data collection and reporting for CEMS systems. Because more substantial modifications would be required of the ECMPS to accommodate the MACT data requirements for detailed reference method test data and other periodically measured pollutants, the EPA has decided to further develop the ERT to receive these data.

2. ERT reporting of emissions test data.

a. Support for ERT reporting.

Comment 4: Commenters 17767 and 17795 agree with the proposed rule that the ERT would be an appropriate means of submitting test results to the agency. Commenter 17795 states that most states will require hard copies or electronic copies for quality assurance and acceptance. According to the commenter, ERT provides the flexibility to upload and import supporting data, and a common system will benefit operators with units in multiple states to have one system to generate reports for the EPA and local regulators.

b. Opposition to ERT reporting.

Comment 5: Several commenters (17621, 17718, 17775, 17790, 17868) express opposition to using ERT for reporting compliance test results, and commenters (17621, 17718, 17770, 17790, 17821, 19033) state that the ERT needs extensive revision before it is used for that purpose.

Response to Comments 4 - 5: The EPA disagrees that the ERT needs extensive revision before it can be used for documentation and delivery of compliance test reports for which it is designed. The EPA also believes that with the January 2012 addition of the ability to satisfy CROMERR compliance several state and local agencies will no longer require wet signature paper test reports. The EPA recognizes that some state and local agencies are reluctant to adopt new programs, assess the experiences of those that do adopt new programs and adopt new programs when they have determined the effort benefits their program goals and available resources. The EPA believes that the use of the ERT will demonstrate to state and local agencies that it provides them with improved ability for compliance oversight, improved responsiveness with resources that are comparable to what they currently use to manage the paper reports which they currently receive. As a result, the EPA expects a reduction in the number of regulatory authorities which require the delivery of paper reports with wet signatures.

i. Performance, susceptibility to viruses, and corruption of data.

Comment 6: Commenter 17730 notes that the EPA is proposing to use the ERT as the platform for sources to electronically report data. The commenter states that the ERT is a Microsoft Access desktop application that is prone to computer viruses, has created several problems in using this application, and is subject to significant performance issues, including software crashes and shutdowns, inoperable features (like report generation), and inadequate identification of errors preventing data analysis. Commenter has banned the use of the Microsoft Access database system on its internal network due to this susceptibility and is, therefore, opposed to its use for uploading data to the EPA WebFIRE database. Commenter is concerned with the corruption of data that may occur due to the susceptibility of this software package to virus infections. The commenter questions how the EPA would ensure that the data that would be submitted to the WebFIRE database would not be infected and require further attention by the EPA or by the source to rectify the information and if the EPA considered the cost of repairing a database that is eventually corrupted by virus attack, and if so, how the repair would be accomplished and the cost to the industry for the effort.

Response to Comment 6: The EPA implements scans and other techniques to ensure that data within its network environment, including data submitted through CDX is free of viruses and other security concerns. The EPA would expect that utilities would likewise ensure that the information it manages within its network and computers remains free of viruses and is not corrupted. It is the source's responsibility to submit complete and accurate data to the EPA.

Comment 7: Commenter 17770 provided examples of the aspects of the ERT that the commenter considers cumbersome. The commenter states that even though the third party emission tester provided the correctly formatted spreadsheet to import into the ERT, there were instances where the ERT would not accept the file. According to the commenter, this resulted in manual input of the data, which was time consuming and frustrating. Commenters 17770 and 17775 noted the program provides no useful error messages when data were input incorrectly. The commenters state that the EPA staff were helpful in correcting these errors, but the entire exercise only proved that the current version of the ERT is not fully developed for everyday use.

Comment 8: Commenter 17790 states that the ERT used for submitting 2010 ICR results and had significant flaws including: not accepting data, incompatible test methods, inoperable features.

Comment 9: Commenter 17621 observes that the ERT provides no error checking or validation capability, and that the program failed to complete emissions calculations with no indication of the reason. According to the commenter, the ERT could also enhance data quality by storing information needed to understand sample results, such as results of analysis of method and field blanks and laboratory quality control samples.

Response to Comments 7 - 9: The EPA recognizes that the ERT provided 2 years ago for use with the utility ICR had some aspects of data entry that required improvement. To the extent that users identified those issues we have modified the ERT to address the issue such that users could successfully provide the required test report with all the necessary documentation. While the commentors may have had difficulties with this earlier version of the ERT, the majority of the ERT's users were provided with adequate information for use in developing the final rule. The EPA understands that the number and detail of information required for the ICR was greater than what we require for compliance tests. The EPA believes that with the increased familiarity in the use of the ERT combined with the revisions to the ERT, the delivery of compliance reports to the EPA will not be a significant issue.

ii. Issues with detection limit flags.

Comment 10: Commenter 17621 states that data flags confuse detected and non-detected results. The EPA requires users to assign a "DLL" (detection level limited) flag to emission measurements with one analytical fraction above detection limit and others below detection limits. The commenter notes that this can cause a degradation of data usability.

Comment 11: Commenter 17821 states that ERT coding for method detection limits is confusing and cumbersome; the ERT does not support the typical non-detect with a (<) symbol. The commenter states that the ERT requires the use of bracketed symbols as a bracketed "less than" detection level value (e.g., [<0.0105]) and that for sample trains with multiple fractions (i.e., Method 29 Metals) this is very confusing and increases the possibility for miscoded data.

Response to Comments 10 - 11: The EPA recognizes that the way the EPA required users to enter individual laboratory components was not the most effective way to provide this information. We also recognize the significant level of resources required of source testers to properly enter laboratory data into their standard reports or into the ERT. This effort duplicates the resources expended by laboratories to enter this information into the report provided to the source tester. This effort is also duplicated again when tests are evaluated by regulatory authorities. The EPA will engage the laboratories to develop an electronic lab report which the ERT will use to populate an expanded laboratory feature to allow for improved capabilities for use by test contractors, state agency reviewers and the EPA.

iii. All required emission test methods are not supported by the ERT.

Comment 12: Commenter 17821 notes that Method 30B (Hg) is not supported by the ERT in the most current version and that in order to use the non-supported methods such as Method 30B a supplemental worksheet is used. According to the commenter, the use of elements outside of the ERT increases the opportunity for errors in both data entry and data review.

Response to Comment 12: The EPA has partnered with a vendor of Method 30B hardware and software to implement the electronic documentation of this test method into the ERT. The implementation of 30B in the ERT will be a non proprietary application so users can use any vendors' hardware or field software to manage the collection and analysis of the samples. This capability will be in the version of the ERT available within 6 months following promulgation of the utility boiler MACT standard.

iv. ERT is burdensome.

Comment 13: Commenters 17730 and 17775 state that use of the ERT is burdensome (easily adding 10-20 percent to the cost of compliance testing), requiring manual inputting of significant amounts of information much of which is not relevant to performance test results. Commenter 17730 states that, contrary to the EPA's assertion, ERT as currently designed, requires the reporting of vast amounts of information that are not otherwise required to be reported under the applicable EPA test methods, or the EPA's proposed rule. Commenter 17730 believes that the EPA's requirement to report electronically is not sufficiently defined to support reporting of all the information that must be entered into ERT in order to submit the data.

Comment 14: Multiple commenters (17718, 17621, 17725, 17790, 17816, 17820, 17881, 18014, 18498) state that using the ERT increases the cost of emission test submittal due to the time needed to manually input significant amounts of information. Several commenters (17718, 17621, 17816, 17881) note that manually inputting data significantly increases the potential for errors in data reporting. Commenters 17718 and 17816 suggest that the EPA should make the tool more user friendly. Commenter 17881 states that using the ERT adds significant costs to the stack testing process.

Comment 15: Commenters 17730 and 17775 state that the ERT requires reporting of information that is not otherwise required to be reported under the applicable EPA test methods, or the EPA's proposed rule. Commenter 17730 believes that EPA's requirement to report electronically is not sufficiently defined to support reporting of all the information that must be entered into ERT in order to submit the data.

Comment 16: Commenter 17775 provides as examples of information required by ERT that is not required under the EPA test methods or the proposed rule: proposed section 63.10030(a) and Table 10 require compliance with section 63.7(c). The commenter states that section 63.7(c) requires development and, if requested by the Administrator, submission of a "site-specific test plan" to the Administrator "at least 60 calendar days before the performance test is scheduled to take place" (i.e., at the same time as the notification of intent to conduct a performance test) but that section 63.7(c) does not require submission of test plan information in the performance test report which obviously is submitted after the performance test is conducted. The commenter states that the EPA also proposes to require compliance with section 63.7(g) (Proposed Table 10). The commenter states that proposed section 63.7(g) requires submission as part of the "results of a performance test," "the analysis of samples, determination of emissions, and raw data," while ERT requires reporting of much more information, and including a test plan. The commenter states that similarly, the EPA's proposed requirement in section 63.10031(h)(1) to report "performance test data" is not sufficiently detailed to support reporting of all of the information that must be entered into ERT in order to submit data.

Comment 17: Commenter 19033 states that using the ERT was very cumbersome, and the reported data was not easily reviewable.

Response to Comments 13 - 17: The EPA disagrees that the ERT is excessively burdensome. The EPA does understand that some users of the ERT did not have electronic versions of field data sheets or laboratory reports which allowed data to be imported into the ERT or that they could use to copy and paste the applicable data. The EPA recognizes that this duplication of effort could result in an increased burden. The EPA also understands that some field test crews preferred to use spreadsheet applications which they developed to match their workflow and data needs. The organization of these proprietary spreadsheet applications did not always match the organization of field data in the ERT. The EPA has developed a supplementary field data spreadsheet module for use with a wide variety of proprietary field data collection spreadsheet applications. We have also provided instructions for merging this supplementary module with proprietary spreadsheet applications. When the supplementary module is merged with the proprietary field data spreadsheet applications, the ERT will import the required information and greatly reduce the effort in entering the field data into the ERT. The EPA is also embarking on an effort which will allow for laboratory information to be electronically populated into the ERT.

The EPA disagrees that the ERT requires the reporting of vast amounts of data that is not currently required for compliance test reports. The commenters may be confusing the presence of a data field as one that requires entry of data. Also, the commenters may be confusing the level of information the EPA required in the ICR with what would be required for a compliance test report. The EPA made the ERT flexible to accommodate a wide variety of existing data requirements specified by various state and local agencies and which are specified in various published EPA test methods and published state and local agency test methods. The EPA does not expect sources to enter data into every available field of the

ERT for every source test. Each state or local agency which has delegated authority has provided guidance on those data elements which they expect in compliance source tests.

v. The EPA has provided no explanation of how WebFIRE will work.

Comment 18: Commenter 17730 states that the EPA has provided no discussion in the preamble regarding how the information required to be submitted under ERT to WebFIRE will benefit the EPA and sources by improving emission factors. Commenter says that the EPA has yet to explain in any detail how the process of emission factor development from performance test data submitted to WebFIRE will work.

Comment 19: Commenter 17775 states that the EPA is requiring reporting to ERT under provisions that are inapplicable, inappropriate, and impossible to implement. According to the commenter, the EPA also has provided no information to suggest that WebFIRE will be operational by the proposed January 1, 2012 deadline. The commenter stated that the proposed requirements should be withdrawn.

Commenter 17775 states that to the extent EPA wants to add subpart UUUUU data to an emissions factor database, the EPA can do that on its own. That is not adequate justification for requiring additional reporting by EGUs. The commenter asks that the EPA fully explain how the process of emission factor development from performance test data submitted to WebFIRE will work. The commenter states that in its comments on the ANPR, the commenter expressed concerns about the process the EPA described and objected to any attempts to mandate submission of reports before the EPA had more completely explained its plans, completed any necessary rulemakings, and made operational its website. According to the commenter, the EPA should not be promulgating requirements intended to support a larger program piecemeal before that program has been fully developed. The commenter asserts that the EPA should reserve the question of mandatory reporting to WebFIRE until it has resolved the questions raised in the ANPR.

Response to Comments 18 - 19: The electronic submission of compliance test reports to the agency through the CDX is not solely for the purpose of developing improved emissions factors. While populating WebFIRE will allow the agency to improve emissions factors, the agency intends to use data stored in WebFIRE as the primary location for compliance test reports for use by regulatory authorities. The electronic submission of compliance test reports is a continuation of the agency's efforts to bring the submission and sharing of environmental data into the modern age. The storage of this compliance data in the EPA's WebFIRE provides a convenient location which is already used to store source test data. As EPA and State and local agencies data systems mature, information provided in the ERT will be used to populate these data systems. The EPA is currently upgrading the AIRS Facility System and expects to replace manually entered information with electronic population from the ERT. The EPA is also working with several state and local agencies to adopt the use of the ERT for delivery of compliance test reports.

vi. Opposition to submittal of RATA data.

Comment 20: Commenter 17718 asked that the EPA clarify whether only CEMS RATA performed under this proposed rule are to be submitted electronically using the ERT and whether only SO_2 RATAs performed for the combined purposes of 40 CFR Part 75 and this proposed regulation would be reported in ERT. The commenter notes that any annual NO_X or flow monitor RATA performed for 40 CFR Part 75 requirements would not to be reported in the ERT even though it may have been performed concurrently.

Comment 21: Commenter 17775 objects to the EPA's suggestion that reporting of RATA results to WebFIRE would be helpful in the development of emission factors. The commenter notes that RATAs are tests of CEMS in comparison to test methods and they are performed under conditions that may or may not be representative of operations the EPA deems relevant to emission factor development. The commenter also objects to the required submissions of results after each "performance evaluation" since that term is defined to include calibrations, which may be performed daily, whereas RATAs likely are performed only once a year and considers the proposed exclusion of "opacity data" is needless, since the rule does not require monitoring of opacity.

Commenter 17775 states that provisions for reporting in section 63.10021(a)(11)(iv) and (v) require sources that use PM CEMS to report "performance test data, except opacity data" and "relative accuracy test audit data" electronically using ERT. The commenter states that in proposed section 63.10021(a)(17)(i) and (ii), the EPA also includes a requirement for reporting of "performance test data, except opacity data" and "relative accuracy test audit data" for LEEs. The commenter objects to these provisions, citing the following points: EGUs using PM CEMS and LEEs do not conduct RATAs. PM CEMS are subject to different tests (RCAs and RRAs). According to the commenter, since LEEs comply by initially demonstrating applicability with emission tests and thereafter by fuel analysis, LEEs have no monitoring systems upon which to conduct RATAs. The commenter asserts that with respect to "performance test data," the provisions are duplicative of a more general provision the EPA proposes.

Comment 22: Commenter 17881 states that all of the information the agency needs to determine an EGU's compliance status already must be reported under the part 63 general provisions, and hard copies of the test reports will be provided to the Administrator (and/or the delegated authority). The commenter does not agree with submitting RATA PM data into the WebFIRE database. The commenter states that for those monitoring systems operated pursuant to 40 CFR Part 75, RATA information is already being submitted to the EPA in an electronic format.

Commenter 17881 disagrees with the provision to submit RATA results through the ERT. The commenter states that the CEMS is the compliance mechanism, not the reference method data that is collected during the RATA.

Response to Comments 20-22: We agree that it is appropriate and supportive of future regulatory reviews that the agency collect data from CEMS RATA testing. The final rule requires that sources submit the test reports resulting from CEMS RATAs via the CDX to WebFIRE.

vii. Use of the ERT should require rulemaking and opportunity for comment.

Comment 23: Several commenters (17730, 17725, 17775) believe it is inappropriate for the EPA to require submission of reports through this rulemaking before the EPA has more completely explained its plans, completed any necessary rulemakings, and made operational its website. Commenter 17730 states that the EPA should not be promulgating requirements intended to support a larger program, piecemeal, before that program has been fully developed. The commenter requests that the EPA provide notice and opportunity to comment on all reporting requirements. The commenter concludes that the EPA should set aside the question of mandatory reporting to WebFIRE until it has fully addressed these issues. The EPA also has provided no information to suggest that WebFIRE will be operational by the proposed January 1, 2012 deadline.

Comment 24: Commenter 17775 states that the EPA should identify the software it proposes to require with sufficient specificity that it can be incorporated by reference into the rule. According to the commenter, if the EPA simply wants to require electronic reporting, the EPA should limit its requirement to a specific format (e.g., xml) and allow sources to procure or develop their own software to comply with that format and the associated reporting elements.

Comment 25: Several commenters (17820, 18014, 18498) state that the development of any reporting tool or reporting format should also follow a transparent development process that includes feedback from the regulated community.

Response to Comments 23 - 25: The EPA disagrees that a separate and independent regulatory action is required to implement electronic reporting for selected regulated sources. Each of these regulatory actions for selected source categories provides ample notice and the opportunity for individuals to provide comment. The EPA also disagrees that the system to receive the compliance data must be operational prior to establishing the requirement for regulated sources to submit compliance data electronically. The EPA is on track to have the capability to receive electronic compliance tests through the EPA's CDX in sufficient time to receive all utility source test reports required by this rule.

The EPA does plan a separate and independent regulatory action to implement electronic reporting for regulated entities which are covered by past and future rules. While we have provided draft procedures for the development of emissions factors, that effort is an ancillary effort to the electronic delivery of compliance test reports. It is the agency's desire to transition to the electronic delivery and storage of air emissions compliance source test data. With this transition, it is believed this valuable information will be more readily available for not only compliance purposes but for a wide variety of other uses.

To the EPA's knowledge, there exists no standardized application for electronically documenting the conduct of source test reports. We believe that the ERT may generate interest in the development of software which is superior to the ERT. Should the agency see this interest, we will develop an XML Schema for source test reports from the data elements used by the ERT. At this time, we do not know of a private enterprise willing to develop software for source test companies to use to document field sampling and to generate a standardized electronic output.

viii. Hard copies of reports are needed for agency review.

Comment 26: Commenter 17719 notes that stack test data reported to state agencies must be considered along with additional, specific information for each source's operations. According to the commenter, this evaluation cannot be easily conducted with the limited data reported in the ERT. The commenter 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. The commenter states that 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 commenter relies heavily upon the submission of written stack test reports. Thus, the commenter supports the EPA's preservation of the submittal of written performance testing reports to state agencies, and states that as a state agency, it intends to continue to request sources to submit hard copies of stack test reports to the state, in addition to the EPA's collection of stack testing data via the ERT and therefore supports the EPA's preservation of related requirements in 40 CFR part 63, sections 63.7 and 63.10. The commenter requests that the EPA consider a way for states to report to the EPA via the ERT that the test is not approvable or was not representative.

ix. Hard copies of reports should not be required.

Comment 27: Commenters 17718 and 17816 state that a source should not be required to make paper or other electronic submittals of the same data submitted through ERT, but should only be required to reference data previously submitted.

Response to Comments 26 - 27: The EPA disagrees that the ERT is unable to store and make available to users all the information that may be required to document the degree of source configuration and operating variables. The ERT provides the ability for the documentation of process operating parameters, laboratory analyses of parameters associated with the process, text descriptions of process, controls, monitoring methodologies and descriptions of testing issues which can be migrated into larger data systems if desired. In addition, the ERT is capable of storing a variety of formats of electronic documents including but not limited to word processing files, spreadsheet files, scanned image files, and ISO standard ISO 32000-1:2008 compliant Portable Document Format files. The continued delivery of only a paper version of source test reports will continue to limit the availability of the information contained in these reports to the individual which receives the report. This will also limit the information which is available to others within the state/local agency, EPA and those needing access to this information to that information that the recipient manually enters into a widely available data system. The EPA believes that it is much more efficient to allow electronic population of data systems and electronic screening of source tests requiring increased scrutiny. The EPA recognizes that states with delegated authority may require sources to provide complete reports in paper form. However, these paper reports with be in addition to the delivery of electronic reports through the EPA's CDX. The EPA encourages state and local agencies to accept electronic reporting in lieu of a paper report.

x. Cross-media Electronic Reporting Rule.

Comment 28: Commenters 17730 and 17775 state that any electronic report used to satisfy federal reporting requirements also must meet the requirements of the Cross-Media Electronic Reporting Rule, codified at 40 CFR part 3, including the requirement that the document include a valid electronic signature, as defined in the rule. Commenter asks that the EPA explain how ERT or WebFIRE meets this requirement and whether ERT can satisfy other criteria the EPA deems necessary for valid electronic reporting, including whether (i) each electronic signature was a valid electronic signature at the time of signing; (ii) the electronic document cannot be altered without detection at any time after being signed; and (iii) each signatory had the opportunity to review in a human readable format the content of the electronic document that he or she was certifying to, attesting to, or agreeing to by signing. The commenter is concerned that the responsible official is unable to prevent revision of the information in ERT at or after the point of submittal.

Response to Comment 28: Submission of the ERT Project Data file through EPA's CDX will be fully compliant with the Cross-Media Electronic Reporting Rule. This includes the signature validation of the authorized official of the regulated source, the addition of electronic means to verify that no changes in the file were made subsequent to submission and the opportunity to review in the test report in a human readable format. As with a wide variety of electronic submissions through the EPA's CDX, the original file submitted to the agency will be maintained with proof of the original signature and proof that the file has not been altered. A copy of the file of record will be stored in WebFIRE and is not required to be CROMERR compliant although the agency does not expect to modify the file. Users requiring verification of the authenticity of the contents of the file will be directed to the CDX where the official copy of record will reside.

xi. Paperwork Reduction Act.

Comment 29: Commenters 17730 and 17775 state that to comply with the Paperwork Reduction Act and its implementing regulations, the EPA must specifically identify each piece of information it seeks to have reported, explain how those data have practical utility, and estimate the costs of collection and the EPA review of those data. According to the commenters, the EPA has not appropriately responded to these requirements in the proposal. Commenters state that if the EPA intends to require reporting of more than the test results already required to be reported under the applicable EPA test methods, the EPA must issue a supplemental proposal identifying and soliciting comment on the information it seeks to collect so that the regulated community and members of the public may have an opportunity to adequately respond to the proposed requirements.

Response to Comment 29: While the ERT may have the ability to store a wide variety of information, there is no information required by the ERT which is not required in this rule or in those source test methods used for demonstrating compliance with this rule. There may be information which are required by the delegated authority but are not stipulated in this rule or test method required by this rule.

5B05 - Recordkeeping/Reporting: Other

Commenters: 17197, 17681, 17691, 17725, 17775, 17820, 17881

1. Electronic reporting.

Comment 1: Commenter 17197 notes that the December 31, 2011 date in section 63.10021(a)(16)(vii) appears erroneous since it specifies compliance notifications that are due long before the rule's 3-year implementation and compliance deadline from final rule Federal Register publication. The commenter also notes that the referenced (CDX) electronic data reporting capability will be available beginning January 1, 2012. The commenter recommends that the date references in the proposed rule be replaced by a time reference (i.e., 180 days, 6 months, 12 months) from final publication of the rule.

Comment 2: Commenter 17881 states that due to the lack of specificity in the data to be submitted as required by section 63.10021(a)(16)(vii), the regulated community will not know how to comply with this requirement; it needs clarification. The commenter states that the EPA database does not currently exist, and therefore it is not possible to constructively comment on this requirement.

Response to Comments 1 - 2: The EPA believes the revisions in the final rule address the calendar date issues, as well as the concerns with proposed section 63.10021(a)(16)(vii).

2. Performance test notification time.

Comment 3: Commenter 17681 asks that the EPA choose 15 days or 21 days rather than the 30 days of notification before performance testing required in section 63.10030(d) of the proposed rule.

Comment 4: Commenter 17691 asks that the EPA require at least 60 days of notification rather than the 30 days of notification before performance testing required in section 63.10030(d) of the proposed rule.

Comment 5: Commenters 17775 and 17820 state that the proposed requirements for notifications to conduct performance tests and compliance status are unclear. The commenters state that proposed section 63.10030(a) requires submission of all of the notifications required under the General Provisions of 40 CFR part 63 (specifically section 63.7(b) and section 63.9(e)), proposed Table 10 also identifies section 63.7(b) and section 63.9 as applicable, sections 63.7(b) and 63.9(e) require notification of "intent to conduct a performance test at least 60 calendar days before the performance test" is initially scheduled to begin, but that proposed section 63.10030(d) requires submission of a "Notification of Intent" to conduct a performance test, "at least 30 days before the performance test is scheduled to begin." The commenters state that this inconsistency should be corrected in the final rule and provide clarity as to whether the 30-day or 60-day notification will be required.

Response to Comments 3 - 5: The final rule requires 30-day notice of all performance tests, and clarifies any discrepancy with the general provisions.

3. Multiple reporting requirements.

Comment 6: Commenter 17775 expresses concern that the proposed rule contains redundant requirements for reporting. The commenter states that in section 63.10031 and Table 10, the EPA proposes to require compliance with most of the reporting requirements in the part 63 general provisions, including requirements for submission of "performance test results" under section

63.10(d)(2), “performance evaluation results” under section 63.10(e), and “excess emissions and continuous monitoring system performance reports” under section 63.10(e)(3). The commenter states that according to section 63.7(g) (applicable under proposed Table 10), performance test results must be submitted as part of the “notifications of compliance status” under section 63.9(h) and must include “analysis of samples, determination of emissions, and raw data”; under section 63.8(e)(5), performance evaluation results, which include results of “relative accuracy testing” and “calibration error tests” also must be submitted simultaneously with any performance test results(40 CFR 63.2)(applicable under proposed Table 10); And that “Excess emissions and continuous monitoring system performance reports” are submitted semi-annually, and must contain the information in section 63.10(c)(5) through (13), section 63.8(c)(7), and 63.8(c)(8).” The commenter states that according to proposed Table 10, some of the provisions in section 63.10(c) are not applicable to subpart UUUUU, and that because the reports are to include information on “excess emissions” “as defined in the subpart, and subpart UUUUU does not define “excess emissions,” these provisions are not complete. The commenter asks that the EPA address these inconsistencies and omissions prior to finalizing the rule.

Commenter 17775 notes that performance test results and notifications of compliance must be sent to the state, the EPA Regional Office and permitting authority (if different than the state). The commenter states that as a result, under the part 63 general provisions alone, most EGUs already will need to prepare and submit three types of reports (in addition to the notification of compliance status) to both the EPA Regional Office and at least one state office: (1) performance test reports, (2) performance evaluation reports for monitoring systems, and (3) excess emissions and monitoring system deviation reports. The commenter states that proposed section 63.100031(h)(3) also requires a hard copy of the ERT reports to be sent to the Administrator, bringing the number of copies of each performance test and performance evaluation report submitted up to at least four.

The commenter further notes that in addition to the semi-annual “excess emissions and continuous monitoring system performance reports” required under section 63.10(e), EGUs would submit the additional information specified for a semi-annual “compliance report” described in proposed section 63.10031 and Table 9. The commenter states that this information presumably includes the “deviation” reports referenced in the preamble. The commenter believes that this is excessive.

Commenter 17881 states that as proposed in section 63.10030(d), there will be limited time to submit a test plan and notice and to receive agency approval, let alone receive and review results from previous test events, prior to the next test event. The commenter suggests that one test notice or report be submitted for all testing conducted within a semi-annual period (or some other reasonable time frame).

Response to Comment 6: The agency agrees with the commenter’s assertion that there is a potential for duplicative reporting. To the extent possible, the rule has been revised to eliminate reporting to both States and permitting authorities where the state is the permitting authority. The rule eliminates duplicative reports to EPA Regional Offices. The agency agrees that clarification is needed so that duplicate copies of the same report do not need to be submitted more than once, and the rule has been revised to eliminate the requirements for more than one copy of any report.
The agency agrees with the commenter regarding the unclear requirements for excess emissions and deviation reports, and the rule has been revised to clarify that all of these reports are excess emissions reports which are referenced in the General Provisions of part 63. Also, the agency is aware that the rule’s exceptions to the General Provisions reporting, as shown in Table 9, will reduce burden on what the facilities need to submit.

The agency is aware of and agrees with the commenter that there needs to be a clear definition of excess emissions; the rule contains such a definition.

Generally, providing adequate notice of and receiving approval of emissions testing are non-federal requirements; should an EGU owner or operator believe timing to be problematic, the rule affords the owner or operator the ability to choose means other than emissions testing to demonstrate compliance.

4. Section 63.10031(c)(7).

Comment 7: Commenter 17881 asks if, assuming that paragraph 63.10031(c)(7) only pertains to units not using CEMS, that can burn the new fuel without meeting the Hg and HCl input operating limits, as long as you perform a compliance test within 60 days and if the test shows compliance, whether there is a deviation to report.

Response to Comment 7: If you combust a new fuel, you must conduct a performance test for that fuel. There are no input operating limits, but you must show compliance with the applicable emission limit. Performance test results must be submitted, but assuming the tests show compliance, there is no deviation to report with respect to the emission limit.

5. Notice of Compliance.

Comment 8: Commenters 17775 and 17820 ask that the EPA clarify if some EGUs are not required to submit a Notice of Compliance Status or revise the section to make clear that all EGUs must submit such a notice, citing inconsistencies between requirements in section 63.10031(e) and section 63.10005(a). The commenters note that proposed section 63.10031(e) requires EGUs to submit a "Notification of Compliance Status" according to section 63.9(h)(2)(ii), "[i]f you are required to conduct an initial compliance demonstration as specified in § 63.10011(a)" but that under proposed section 63.10005(a) all EGUs "must demonstrate initial compliance with each of the applicable emission limits in Tables 1 or 2..." and that, section 63.9(h) on its face applies to each affected source when it becomes subject to a relevant standard.

Commenter 17775 states that under paragraph (3), the Notification of Compliance Status must include "[i]dentification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing and fuel analysis; performance testing with operational limits (e.g., CEMS for surrogates or CPMS); CEMS; or sorbent trap monitoring system." The listed options do not appear to correspond with the rest of the proposed rule. The EPA needs to issue a proposal that clearly articulates the various compliance demonstration options.

Commenter 17775 states that under paragraph (3), the Notification of Compliance Status must include "[i]dentification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing and fuel analysis; performance testing with operational limits (e.g., CEMS for surrogates or CPMS); CEMS; or sorbent trap monitoring system." The listed options do not appear to correspond with the rest of the proposed rule. The EPA needs to issue a proposal that clearly articulates the various compliance demonstration options.

Response to Comment 8: The language cited in the first paragraph above has been changed to "initial performance test," so that, for example, the notification requirement does not apply to the work practice standard and performance tune-up. The language in section 63.10030(e)(3) cited in the second paragraph has been revised to clarify the compliance options consistent with the final rule.

6. SSM reporting.

Comment 9: Commenter 17725 suggests that the EPA consider reporting startup, shutdown, and malfunction reports listed in Table 9 to subpart UUUUU of part 63 Reporting Requirements via email so notification can be made concurrently to any necessary state or local reporting agencies as well. According to the commenter, this would also allow for a document trail to be maintained and eliminate the unnecessary use of maintaining both paper and electronic records.

Response to Comment 9: The general provisions apply similar to other NESHAP and the specific applicability of the General Provisions to EGUs is addressed in Table 9 of the final rule. Notices are required to be delivered or mailed to the address specified. A courtesy email may be sent as an unofficial notification.

5C01 - Compliance: Dates

Commenters: 15678, 16122, 16469, 16705, 16824, 16849, 16850, 16856, 16858, 17003, 17004, 17022, 17026, 17028, 17055, 17055, 17110, 17123, 17137, 17174, 17254, 17265, 17297, 17383, 17385, 17400, 17402, 17403, 17406, 17408, 17608, 17623, 17627, 17637, 17638, 17640, 17648, 17654, 17655, 17656, 17675, 17677, 17681, 17689, 17696, 17697, 17701, 17703, 17705, 17707, 17711, 17714, 17715, 17716, 17718, 17719, 17720, 17722, 17724, 17725, 17730, 17731, 17732, 17734, 17735, 17736, 17738, 17740, 17741, 17752, 17756, 17757, 17758, 17761, 17765, 17767, 17770, 17774, 17775, 17776, 17789, 17790, 17791, 17796, 17797, 17798, 17799, 17800, 17805, 17807, 17808, 17810, 17812, 17813, 17815, 17816, 17817, 17818, 17819, 17820, 17821, 17824, 17829, 17834, 17837, 17840, 17841, 17842, 17843, 17844, 17846, 17852, 17854, 17856, 17857, 17868, 17870, 17873, 17876, 17877, 17878, 17879, 17881, 17883, 17885, 17886, 17887, 17902, 17904, 17909, 17911, 17912, 17913, 17918, 17919, 17925, 17930, 17931, 17973, 18016, 18021, 18024, 18025, 18026, 18027, 18031, 18033, 18034, 18037, 18038, 18039, 18419, 18421, 18422, 18422, 18424, 18425, 18426, 18428, 18430, 18433, 18434, 18437, 18438, 18439, 18440, 18441, 18442, 18447, 18448, 18450, 18477, 18487, 18498, 18500, 18501, 18502, 18539, 18541, 18575, 18933, 19032, 19114, 19121, 19122, 19212, 19213, 19506, 19653, 8443, 9738, 19536, 19537, 19538, 18023

1. General comments.

Comment 1: Multiple commenters (16850, 16858, 17004, 17022, 17026, 17028, 17110, 17654, 17689, 17715, 17724, 17740, 17797, 17820, 17821, 17868, 17909) ask that the compliance date be clearly stated as soon as possible, as well as guidance for utilities unable to comply with the stated timelines, to allow time for utilities to prepare.

Response to Comment 1: The compliance date for the final rule is set forth at 40 CFR 63.9984. New sources must be in compliance with the standards on the effective date of this rule or at start-up, whichever is later. Existing sources must be in compliance 3 years after the effective date of this rule. . Three years is the maximum compliance time authorized under the statute. *See* CAA section 112(i)(3)(A). If sources are unable to comply within 3 years, the owner or operator may seek a 1 year extension of the compliance period from its Title V permitting authority if the source needs the additional time to install controls necessary to comply with the final rule. *See* CAA section 112(i)(3)(B).

The EPA sends rules to the Federal Register once they are signed. We do not know exactly when the rule will be published in the Federal Register but it is likely to take a month or more. As we have stated elsewhere, we believe utilities should already be in the process of planning for compliance with this regulation.

Comment 2: Multiple commenters (17174, 17265, 17648, 17654, 17681, 17689, 17740, 17774, 17796, 17820, 17821, 17868, 17873) ask that any decisions or policies on extensions be published in a rulemaking.

Comment 3: Commenters 18034 and 18447 request clarification on what actions the federal government will take to ensure reliability. Commenter 18034 also recommends the EPA clarify any possible discretionary enforcement the EPA may plan to exercise for states that may receive delegation of the new rule.

Commenter 18034 states that EPA makes several vague statements about steps to ensure a reliable and reasonably-priced supply of electricity, particularly regarding localized issues, but does not provide any details concerning what authority would be exercised. The commenter states that in one discussion (76 FR 24979), the EPA indicates that the federal government will work with companies to ensure a reliable and reasonably priced supply of electricity, and in a separate discussion (76 FR 24979), the EPA states that they believe they have the ability to work with companies making good faith efforts to comply with the standards so that consumers in those areas are not adversely affected. According to the commenter, the EPA should be clear about the steps it may take and what the federal government might do to provide all parties the opportunity to comment on the appropriateness and legality of the actions that the EPA and other agencies of the federal government are considering. The commenter states that additionally, states that might receive delegation of this regulation should be made aware of possible discretionary enforcement the EPA may plan on exercising. The commenter states that rather than pointing to vague steps that the EPA and the federal government may take to address electrical power system reliability problems after they occur, the EPA should be considering the consequences of their actions on the electrical power system and building an adequate safety margin into their rulemaking efforts to ensure that the electrical power system of the country is protected.

Commenter 18447 states that EPA states in the proposal preamble that "the Federal government will work with companies to ensure a reliable and reasonably-priced supply of electricity." The commenter asks "How does the Federal government propose to fulfill this promise?" The commenter points out that maintaining generation capability and output from their facility is very important not only for satisfying the electrical demand (load) of the City of Ames and Iowa State University, but also for providing voltage support and electrical stability to the interconnected electric system of central Iowa. The commenter further notes that the impacts on the planning reserve margins and the need for more resources is a function of the tight compliance timeline associated with the proposed rules. "Potential constraints of skilled construction labor, material shortages, financing, and escalation of compliance costs coupled with coordination of overlapping outages resulting in congestion expense could present challenges in meeting the compressed time schedule," NERC concluded.

Response to Comments 2 and 3: Some commenters asked that EPA, by rulemaking, extend the compliance timeframe for this regulation. Many of these commenters wanted the certainty that including the compliance timeframe through rulemaking would afford. Some of these commenters suggested unique situations where providing the extension could be crucial. Public power facilities might need additional time because many of them must obtain approval from public bodies for the compliance activities that might require a public process that can be time consuming. Some commenters felt that smaller facilities would have difficulty procuring the engineering, labor and equipment needed for compliance. CAA section 112 specifies the dates by which affected sources must comply with this rule. New or reconstructed units must be in compliance immediately upon startup or the effective date of this rule, whichever is later. Existing sources may be provided up to 3 years after the rule's effective date to comply with the final rule; if an existing source is unable to comply within those 3 years, a permitting authority has the ability to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls.

The CAA allows CAA title V permitting authorities the discretion to grant extensions to the compliance time of up to one year if needed for installation of controls. *See* CAA section 112(i)(3)(B)). Permitting authorities should be familiar with the operation of the 1-year extension provision because EPA established regulations to implement the provision and the provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(i).

We believe that the permitting authorities have the discretion to use this extension authority to address a range of situations in which installation schedules may take more than 3 years.

The EPA's authority to provide relief from the requirements of this final rule beyond the fourth year is limited by the statute. If reliability issues do develop, however, the CAA provides mechanisms for sources to come into compliance while maintaining electric reliability. One area where the EPA has some measure of flexibility is with respect to the exercise of its enforcement authorities. Please see the preamble to the rule for an in depth discussion of both the 1-year extension and authorities beyond the fourth year.

Comment 4: Multiple commenters (17402, 17403, 17623, 17648, 17714, 17740, 17774, 17799, 17808, 17858, 18021, 18034, 18450, 18500) ask that the EPA establish, streamline, and simplify the process of applying for the 1-year extension under section 112(i)(3).

Commenter 17403 suggests that a commitment to install wet or dry scrubber, fabric filter, DSI, or other major emissions control equipment would automatically qualify the particular unit for the extension.

Several commenters (17808, 17648, 18450) suggest that companies requesting an extension have a compliance plan outlining the steps and timing of the project. Commenter 17648 also suggests operating criteria that must be maintained during the extension, to minimize emissions and remove any economic incentive of deferring compliance.

Commenter 17797 asks that the EPA outline the conditions in which an additional year for compliance with the proposed regulations would be granted. The commenter requests that power companies be allowed to operate on a restricted basis without additional controls as they upgrade their facilities.

Response to Comment 4: The EPA established General Provisions applicable to CAA section 112 standards at 40 CFR part 63, subpart A. Included in those provisions are regulations implementing the 1 year compliance extension provision of CAA section 112(i)(3)(B). *See* 40 CFR 63.6(i)(4). The EPA did not propose to revise those regulations for EGUs in the proposed rule and we are not issuing amendments to those provisions in the final rule. We believe that sources should make themselves familiar with the regulations and contract the state permitting authority as early as possible if the source determines that it will need a 1 year extension.

Comment 5: Multiple commenters (17403, 17623, 17714, 17758, 17774, 17799, 17868) ask that the EPA develop procedures and criteria related to the Presidential exemption under section 112(i)(4). Multiple commenters (17758, 17820, 17868, and 18539) ask that the utility demonstrate good faith progress toward compliance.

Response to Comment 5: The EPA is not authorized to implement the Presidential exemption provision in CAA section 112(i)(4). That provision authorizes the President to provide 2-year renewable extension for sources to comply with the final standards if he determines that the technology to comply with the rule is not available and the extension is in the national security interest of the U.S.

Comment 6: Commenter 17808 suggests that the EPA require utilities to submit a notice concerning which EGUs will be retrofitted or retired – within 1 year of the effective date.

Comment 7: Several commenters (17701, 17791, 18034) encourage the EPA to coordinate with FERC, DOE, and state and federal regulators to maintain system reliability. Commenters 17701 and 17791 suggest the EPA develop a process that will require all generators to provide notice to FERC, system operators, and state regulators of expected effects of the EGU MACT and other EPA regulations. The commenters believe that such a process would provide an opportunity for meaningful assessment and response to reliability issues. Commenter 18034 recommends the EPA work closely with the regional agencies, such as (PUCT and ERCOT) that are responsible for monitoring and assuring the reliability of the electrical power system to ascertain the impact of the new rules on Texas' and the nation's electrical power system.

Commenter 17824 urged the EPA to adopt more flexible standards and reasonable compliance timelines, which will achieve the Agency's goals while ensuring affordable utility bills, stable jobs and reliable power.

Response to Comments 6 - 7: The EPA is not requiring that sources provide notice within 1 year of the effective date of the rule, as to which units will retire and which units will be retrofitted to comply with the final rule. However, the Agency does encourage facility owners to notify the permitting agencies, the transmissions operators, and state regulatory agencies as early as possible of their intention to retrofit or close. Early notification will help to ensure that permitting is orderly and timely for plants that are retrofitting. It would also provide transmissions operators an early heads up so that they can plan for transmission upgrades to avoid reliability problems. It would also allow market solutions including new generation and demand side management solutions to come into the market and ensure grid stability.

Comment 8: Commenter 17648 suggests a process based on early notification of retirements.

Comment 9: Commenter 18441 asserts that the 3-year time period is insufficient for making necessary transmission upgrades. They argue that although certain local reliability upgrades such as those that entail upgrades to existing substations can occur in an expeditious manner, other kinds of transmission upgrades may involve far more complex projects with extended delays. The commenter provides the following three examples to support their statements:

- The need for the Susquehanna-Roseland line was first identified by PJM and approved by the Board as part of 2007 RTEPP and was anticipated to be in service for 6/1/2012 to avoid identified reliability criteria violations. However, they note that delays due to National Park Service review have delayed the in-service date of this line to 2015 at the earliest.
- The retirement by Exelon Generation of the Cromby Unit 2 and Eddystone Unit 2 requires 18 separate transmission system enhancements to address the identified thermal, voltage and short circuit violations. The commenter notes that even though Cromby and Eddystone provided notice of deactivation in December, 2009, due to the need for such transmission enhancements the units are not going to actually shut down until May, 2012.
- A deactivation request for the Benning Road and Buzzard Point generating units (totaling 790 MW, located in the Potomac Edison Power Company's zone in Washington, D.C.) was submitted with PJM in February, 2007. Transmission reinforcements necessary to allow these generating units to retire, which include new circuits, upgrades to existing circuits, new transformers, new capacitors and upgrades to existing terminal equipment, are not expected to be in service until more than five years after such notice in May, 2012.

The commenter states that the analysis supporting the Proposed Rule has underestimated the risks to reliability of electric supply in light of the hard deadlines imposed pursuant to Clean Air Act § 112. Moreover, as EPA indicated, unit owners must only give 90 day notice prior to shutdown in the PJM region, 76 FR 25056. According to the commenter, the requirement to be in compliance three years following publication in the federal register, 40 CFR §63.9984, may result in the shutdown of certain units that are critical to the reliability of electric supply on a timeline that is faster than the time necessary to replace the power or upgrade transmission.

Comment 10: Multiple commenters (17716, 17701, 17791, 17804, 17813, 18034, 17868, 17911, 17913, 17919, 18441, 19114, 18034, 18441, 18500, 18538) express concern that the EGU MACT may cause local transmission problems due to early retirement of EGUs. These commenters argue that the EPA should have assessed reliability at much more local level rather than relying only on national studies of reliability. Commenter 18034 notes that ERCOT anticipates localized impacts on transmission reliability in the Houston and Dallas-Fort Worth areas as a result of the EGU MACT and other EPA regulations. Commenter 17701 notes that small older plants that would likely retire as a result of the EGU MACT and other environmental regulations may need to stay running for a longer period of time because they provide service to an area that cannot otherwise get reliable power (a load pocket) or they provide a key reliability service (e.g., black-start facilities). Commenter 17919 believes that those areas most reliant upon coal-fired capacity are likely to face profound price, supply, and reliability concerns and that in the event of extraordinary events, only the additional peak-load capacity supplied by coal-fired facilities are likely to provide the resilience necessary to address potential weather-related blackouts or even cyber-security threats to critical infrastructure. Commenter 17731 believes that reduced grid reliability will be exacerbated by heavier reliance on non-final (i.e., interruptible) transmission and gas transportation contracts that can result in curtailed deliveries of energy during peak periods when the energy is most needed.

Comment 11: Commenter 17716 considers the EPA to be downplaying transmission problems related to compliance. The commenter notes that transmission problems can arise because current paths are not used after plant retirement, or new/expanded transmission paths are needed for purchased power to replace that from retired plants.

Comment 12: Commenters 17868 and 18500 mention recent blackouts in the ERCOT region of Texas as an example of localized reliability problems resulting from too many units out of service at one time during a cold weather event. Commenter 17868 suggests the EPA review the Texas PUC report on the February 2-3, 2011 outage in Texas to understand the implications of reduced electricity supply. The commenters believe this event is an important reminder that having generation offline for upgrades even during a low load season has its risks.

Comment 13: Several commenters (17912, 18034, 18441, 18538, 18023) believe a more detailed study of the impacts of the EGU MACT on reliability of the electric network should be undertaken by the EPA. These commenters identify several areas in which they believe the EPA's analysis of reliability impacts is incomplete or inaccurate.

1. Commenter 17912 believes the EPA's assessment of the impact of the rule on reliability failed to take into account differences between IPPs and regulated utilities. The commenter notes that IPPs do not have a regulated utility's ability to shift load to other units because many IPP facilities are subject to regional reliability mandates that require firing with oil.
2. Commenter 18538 believes the EPA has overstated the ability of energy efficiency and demand response programs to mitigate the reliability impacts of the various EGU rules.
3. Commenter 18538 believes the EPA has understated the reliability impacts of the rule by using low target reserve margins. In the ERCOT region, the commenter argues that the EPA uses a target reserve margin of 12.5% instead of the 13.75% used by ERCOT for planning purposes. The commenter believes the EPA's target margin would likely result in greater incidence of system outages than is considered acceptable in the electric industry. According to the commenter, ERCOT

adopted its 13.75% minimum reserve margin based on the results of a loss-of-load study, which is a probabilistic assessment of the likelihood of a system outage event. The commenter states that the study takes into account components of system volatility, including the forced outage and derating of generating facilities, load forecast uncertainties resulting from weather, and the intermittent nature of wind generation and that consistent with industry practice, ERCOT sets its minimum reserve margin at a level such that the expected frequency of a loss-of-load event is no more than 1 day in 10 years. According to the commenter, the EPA's target reserve margin of 12.5% would increase the likelihood of a loss of load event from 1 day in 10 years to approximately 2.5 days in 10 years. By using a target reserve margin below that required by ERCOT, the commenter argues that the EPA has understated the impact of the various rules on electric reliability in the ERCOT region.

4. Commenter 18034 notes that the EPA's modeling assumes unlimited transmission capability within a model region (e.g., power generated anywhere in ERCOT can be transmitted anywhere in ERCOT) and states that this is not correct. The commenter notes that electrical power cannot be transmitted in an unlimited manner from anywhere to anywhere within a region as large as ERCOT and that fundamental principles of electrical transmission, such as thermal restrictions on transmission lines and voltage stability, restrict the distance that power can be transmitted over power lines within a region.
5. Commenter 18034 questions whether the EPA's analysis accounted for units classified as Reliability-Must-Run (RMR) facilities that are necessary to ensure grid reliability in specific local areas.
6. Commenter 18034 notes that the 25% surplus reserve margin that the EPA cites as an indication that projected retirements will not affect reliability is a national average and is not consistent with ERCOT's local projections for Texas. The most recent information from ERCOT, they argue, indicates that the ERCOT region currently has 17.5% of surplus reserve (*Report on the Capacity, Demand, and Reserves in the ERCOT Region,* May 2011); however, ERCOT expects this surplus reserve will drop to 11.1% by 2014 even without impacts of the EPA's regulatory initiatives, which is less than ERCOT's target reserve of 13.75%.
7. Commenter 18034 believes the EPA has also over-estimated the generation potential of wind energy. They note that ERCOT derates wind capacity using an 8.7% capacity factor because wind generation is unpredictable and unreliable as a generation source. The EPA appears to be assuming that wind generation is capable of producing at 100% of the installed capacity, which is not correct and results in the EPA over-estimating wind capacity in ERCOT by 9,400 MW.
8. Commenter 18034 states that the EPA included retired and mothballed units in their capacity calculations. The commenter notes that the actual total generation resource capacity for ERCOT is 73,175 MW, based on the May 2011 ERCOT report, which is substantially less than the EPA's estimated 90,400 MW for the base case. A recent ERCOT study, entitled *Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System*, issued on May 11, 2011, the commenter asserts, finds that without additional replacement generation the reserve margins could be reduced to less than 2% by 2015 as a direct result of the EPA's regulatory initiatives on EGUs.
9. Commenter 18441 argues that the EPA analysis erroneously assumes (1) wholesale power markets mirror least-cost planning models; reliability is related to only movements of power between large geographic areas; and (2) that there are no transmission or deliverability constraints within those areas. These errors, the commenter argues, result in conclusions that are not correct for RTOs. The commenter notes that retirement and new entry decisions are made in a decentralized manner based on price signals that are provided by wholesale markets that signal the financial profitability of existing and new entry resources. The commenter states that in contrast, the IPM employed by the EPA to model reliability impacts does not reflect the manner in which decisions are made in the wholesale market. According to the commenter, the objective of the IPM is to minimize the system-wide, region-wide, or nation-wide cost of achieving resource adequacy and maintaining its

representation of transmission reliability subject to the environmental constraints imposed on generating units by the proposed rule. The commenter states that in sharp contrast to market dynamics, in the IPM modeling framework employed by the EPA, the retirement and new entry decisions are centralized; the decisions, are not based on market price signals and do not depend upon unit profitability or returns on investment. Rather, according to the commenter, the decisions are based on cost and perfect foresight of future market conditions. As a consequence, the commenter believes the IPM model may reflect retirement and new entry decisions that differ significantly from the actual market-based retirement and new entry decisions.

10. Commenter 18441 notes that the IPM framework does not account for Demand Response and Energy Efficiency resources as new capacity entry or account for the effect these resources may have on market prices that drive retirement and new entry decisions. The commenter notes that wholesale energy and capacity markets in PJM allow for the participation of Demand Response and Energy Efficiency. According to the commenter, since these resources are generally lower cost capacity alternatives than traditional generation resources, the commenter argues that they can have an effect on market prices and ultimately on the retirement and new entry decisions of generation resources when considered in conjunction with the costs imposed by the EGU MACT. The commenter believes the IPM framework is likely missing possible generation retirements that may be driven by the interaction of the EGU MACT with these potentially lower cost capacity resources. The commenter is concerned that the EPA's analysis understates the volume of system security and local reliability issues faced by RTOs and other transmission operators.
11. Commenter 18447 states that the IPM modeling of regions misses large 500 kilovolt ("kV") reactive transfer interfaces that reside within some of the regions. The commenter also notes that some of the regions span across multiple RTOs and each RTO region undertakes its own security constrained generation dispatch. According to the commenter, the manner in which power is moved from one region to another in IPM does not account for parallel path or loop flows that occur across multiple regions and the international border between the U.S. and Canada that take careful inter-regional coordination between multiple RTOs and transmission providers to solve. The commenter notes that the recent Independent Market Monitor ("IMM") reports for PJM states that the amount of generation available to be redispatched to alleviate localized constraints to maintain transmission security is small, sometimes only one or two generating units have the ability to relieve such localized constraints. The commenter argues that the deactivation or retirement of some generation would take away potential re-dispatch solutions and therefore likely trigger the need for transmission upgrades to prevent transmission reliability criteria violations. The commenter notes that more than half of all the pending deactivations require transmission upgrades to allow the unit to retire without a violation of transmission reliability criteria.
12. Commenter 18023 believes that the EPA's analysis is overly simplistic and incorrectly assumes that demand response, energy efficiency, and rapid and wide-spread deployment of renewable energy resources will sufficiently replace lost coal-fired generation capacity both from a resource adequacy and bulk power system operations standpoint. The commenter argues that renewable generation resources and demand response do not provide inertia, frequency response, or voltage support.
13. Commenter 18023 believes that the EPA has underestimated the impact that a decrease in available generating resources will have on the ability of authorities to comply with the reliability standards. The commenter believes the EPA's failure to take into account mandatory BAL and VAR reliability standards (among others) in its discussion of reliability impacts of the Utility MACT is a significant error. The commenter argues that violations of the reliability standards have a wide variety of negative consequences for the electric system, including load shedding and black-outs. The commenter notes several potential operating reliability impacts of the Utility MACT rulemaking:

- Contingency Reserves: requires resources sufficient to address system disturbances; 50 % must be "spinning reserves" (*i.e.,* reserve capacity at units already on-line);
- Load-Following Reserves: requires resources sufficient to respond to load changes within an hour;
- Regulating Reserves: requires resources sufficient to control system performance by responding within 4-6 seconds; all regulating reserve must be "spinning";
- Frequency Control: requires sufficient resources capable of automatically and instantaneously responding to changes in frequency caused by constant tracking and matching of power demand and power supply to prevent imbalances;
- Voltage support: needed to enable the transmission of electricity over distance. Grid operators must ensure there is enough reactive power at the right locations to support the electricity that is being delivered on the system; and
- In addition to all NERC standards developed and implemented by NERC/SERC, utilities must also satisfy planning reserve margin requirements established by NERC/SERC, as well as resource adequacy expectations established by state public utility regulators.

Comment 14: Commenter 17731 questions the EPA's view that utilities can easily retire and replace units that are unable to comply with the new emission limits. The commenter considers the option of replacing older units with more efficient units to be risky because they utility may spend the time and money to build new coal-fired units only to find out that the units cannot comply with the stringent new unit emission limits.

Response to Comments 8-14: The EPA agrees with these commenters that real threats to reliability from these rules are unlikely but agrees as well that a process involving early notification can promote confidence in reliability and as well as promote the kind of planning by companies, regulatory agencies, grid operators, and reliability organizations that can ensure a smooth transition to cleaner electric generating fleet.

The industry has adequate resources to install the necessary controls and develop the new capacity that may be required within the compliance time provided for in the final rule.[3] The EPA believes that the flexibility of permitting authorities to allow a fourth year for compliance should be available in a broad range of situations (as discussed in the preamble), and that this flexibility addresses many of the concerns that have been raised. Furthermore as indicated below, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability.

Although there are a significant number of controls that need to be installed across the industry, with proper planning, we believe that the compliance schedule established by the CAA can be met. Many companies have begun to do the detailed analysis and engineering and are ahead of others in their compliance strategy. There are already tools in place (such as integrated resource planning, and in some cases, forward auctions for future generating capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as this final rule.

The EPA agrees with these commenters that if companies that intend to retire EGUs formally notify their RTO (or comparable planning coordinator in the case of non-RTO regions), state regulatory

[3] As stated above, EPA has provided the maximum compliance time authorized under CAA section 112(i)(3)(A).

agencies, and regional reliability entities as soon as possible that they will retire, it would help to alleviate any local reliability concerns.. As we said before, in most places a closing plant will not be a cause for concern. To the extent there is concern, however, early notification will provide an opportunity for transmission planners, market participants, and state authorities to develop solutions to avoid a reliability problem. In RTOs with forward capacity markets, owner/operators that do not bid generating capacity that they plan to close will provide an advance signal to market participants to take action to assure adequate future capacity. In all regions, early and public notification will allow market participants, planning coordinators and state authorities, as appropriate and in a timely fashion, to bring new generation on line, put demand side resources in place, and/or complete any transmission upgrades needed to circumvent a potential issue. Most RTOs only require 45 to 120 days notification of closure. The 5 RTOs suggested that such notification should be made no later than 12 months after this regulation is final in order to allow a smooth transitioning to action to avoid a reliability problem. The EPA strongly encourages early notification, and believes that responsible owner/operators should and will do the early planning for compliance and provide early notification of their compliance plans, especially where such plans include retiring one or more units.

On the supply side, there are a range of options including the development of more centralized power resources (either base-load or peaking) and/or the development of cogeneration or distributed generation. Even with the current large reserve margins, there are companies ready to implement supply side projects quickly. For instance, in the PJM region, there are over 11,600 MW of capacity that have completed feasibility and impact studies and could be on-line by the third quarter of 2014.[4] The EPA notes, as well, that in the 3 years from 2001 to 2003, industry brought over 160 GW of generation on line.[5]

Demand side options include energy efficiency as well as demand response programs. These types of resources can also be developed very quickly. In 2006, PJM had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to almost 8,000 MW of capacity.[6] In addition to helping address reliability concerns, reducing demand through mechanisms such as energy efficiency and demand side management practices has many other benefits. It can reduce the cost of compliance and has collateral air quality benefits by reducing emissions in periods where there are peak air quality concerns.

With regard to transmission, recent experience also shows that, in many cases, transmission upgrades to address reliability issues from plant closures can be implemented in less than 3 years. For instance, when Exelon notified PJM of its intention to retire four units,[7] it was determined that transmission upgrades necessary to allow retirement of two units could be made within 6 months of notification, transmission

[4] Paul M Sotkiewicz, PJM Interconnection, Presentation at the Bipartisan Policy Commission Workshop Series on Environmental Regulation and Electric System Reliability, Workshop 3: Local, State, Regional and Federal Solutions, January 19, 2011, Washington DC, http://www.bipartisanpolicy.org/sites/default/files/Paul%20Sotkiewicz-%20Panel%202_0.pdf, slide 6

[5] National Electric Energy Data System (NEEDS 4.10) (EPA, December 2010)

[6] BPC slides cited above – slide 5

[7] http://www.exeloncorp.com/Newsroom/pages/pr_20091202_Generation.aspx?k=eddystone

upgrades for the third unit would require slightly over 1 year and transmission upgrades to allow the fourth unit to retire could be made in approximately 18 months.[8]

The CAA allows CAA Title V permitting authorities the discretion to grant extensions to the compliance time of up to one year if needed for installation of controls. *See* CAA section 112(i)(3)(B)). If an existing source is unable, despite best efforts, to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is warranted. This provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(i). We believe that the permitting authorities have the discretion to use this extension authority to address a range of situations in which installation schedules may take more than 3 years.

The EPA does not believe there will be a significant impact on oil facilities as a result of the final rule. The rule contains "limited use" provisions that will mitigate the impacts on many oil-fired facilities used for peaking and/or reliability purposes. For those units that are expected to continue firing residual oil, many already have existing air pollution control technologies (e.g., electrostatic precipitators) necessary to achieve the emission standards and the remaining units that are not capable of converting to another fuel (e.g., subject to natural gas curtailment) are expected to install cost-effective air pollution control technologies. The EPA used AEO demand forecasts as the baseline for electricity demand. The EPA does not believe these forecasts overstate the impact of energy efficiency. The EPA used the official target reserve margins that were available at the time of the analysis of the final rule in the 2010 Long Term Assessment. In the case of ERCOT, the reserve margin was 12.5% percent in that assessment, but was updated after the margins were provided to NERC for the 2010 Long Term Assessment. The EPA's IPM modeling of MATS shows that ERCOT would continue to meet its target reserve margin even taking into account its recently revised target of 13.75 percent. *See* TSD on Resource Adequacy for EPA resource adequacy results. The EPA believes the regional impact evaluation that it conducted was correct in focusing resource evaluation at the regional level, and treating local reliability issues within regions as best handled by standard reliability management practices as the rule is implemented. Processes for addressing local reliability issues have been made more flexible in response to comments received on the proposed rule and are discussed in the preamble. See also responses elsewhere on local reliability issues. As the commenter notes, ERCOT reserve margins are above their target margin in 2012. The EPA agrees with the commenter's recognition that ERCOT's projected capacity shortage shown in that report is not primarily driven by EPA regulations. The EPA believes that there will be sufficient time to add more capacity where needed in ERCOT by 2015; EPA has also included additional flexibility on timing of compliance in the final rule. The EPA's IPM modeling does not purport to capture all potential local reliability variables affecting any specific unit. The final rule provides greater flexibility when additional time is needed to address transmission issues arising from reliability violations related to plant retirements. As noted earlier, the EPA modeled demand based on the AEO, which includes an estimated level of demand response. The reliability contribution from renewable resources is a relevant issue only for wind resources. The reliability capacity contribution from wind resources in the analysis of the rule was based on estimates from the National Renewable Energy Laboratory (NREL) and was incorporated in the resource adequacy assessment (*See* IPM documentation of wind resource and TSD on Resource Adequacy.) Local reliability issues can be addressed during implementation of MATS.

---

[8] Cromby Units 1 and 2 and Eddystone Units 1 and 2 – Deactivation Study, Updated September 7, 2010 - http://policyintegrity.org/documents/20100907-cromby-and-eddystone-retirement-study-posting-update.pdf

Comment 15: Commenter 17725 asks that the compliance date align with the Power Year used by RTOs.

Response to Comment 15: The compliance date for existing sources subject to this rule is 3 years from this rule's effective date. That is the maximum amount of time permissible under CAA section 112(i)(3)(B) which the EPA felt appropriate given the significant work that some plants will need to undertake to come into compliance.

Comment 16: Commenter 17821 asks that the EPA develop guidance on applicability of section 112(i)(6) in the final rulemaking.

Response to Comment 16: There are regulatory provisions in 40 C.F.R. section 63.6 (the general provisions) that govern the use of CAA section 112(i)(6).

Comment 17: Commenter (17887) supports the provision in the NARUC resolution that the rule should allow sufficient time for generators to evaluate and implement the best compliance options and integrate these options into their systems in order to ensure reliability of operations.

Response to Comment 17: The EPA has consistently said that early planning for compliance is very important and we have urged utilities to take proactive steps in coordination with relevant planning and regulatory authorities. The industry has adequate resources to install the necessary controls and develop the new capacity that may be required within the compliance time provided for in the final rule.[9] Although there are a significant number of controls that need to be installed across the industry, with proper planning, we believe that the compliance schedule established by the CAA can be met. Many companies have begun to do the detailed analysis and engineering and are ahead of others in their compliance strategy. There are already tools in place (such as integrated resource planning, and in some cases, forward auctions for future generating capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as this final rule.

Commenter 18: Commenter 17701 representing the National Association of Regulatory Utility Commissioners (NARUC) states that although there are logistical issues that may impact system reliability given the Proposed Rule's compliance timeframe such as: coordination of offline time for the installation of pollution controls on several plants in the same region; repowering or replacing a plant with a natural gas generator relies on access to natural gas pipelines; and transmission solutions generally take longer to plan, site, build and interconnect than the proposed rule's 3- to 4-year compliance timeframe, the association's members will work with their utilities to ensure that customers maintain access to safe and reliable power while generating plants install controls or while plants are retired and replaced or repowered.

Response to Comment 18: The EPA appreciates this comment and agrees that the state regulators have an important role to play in assuring that the transition to a cleaner electric generating fleet that this rule will bring about occurs as smoothly as possible so that reliable power is maintained.

Comment 19: Commenter 17701 advocates flexibility in the implementation of this and other rules to avoid compromising electric system reliability while minimizing cost impacts to consumers. According

[9] As stated above, EPA has provided the maximum compliance time authorized under CAA section 112(i)(3)(A).

to the commenter, flexibility will enable the EPA to accommodate the highly localized and regional nature of electricity services and avoid reliability issues.

Comment 20: Commenters 17701 and 17791 suggest the EPA allow utilities (1) to coordinate the closure and/or retrofitting of existing electric generating units in an orderly manner that will ensure the continued supply of electricity; (2) allow regulatory options for units that are necessary for grid reliability that commit to retire or repower; (3) allow an EPA-directed phasing-in of the regulation; and (4) establish interim progress standards that ensure generation units meet the EPA regulations in an orderly, cost-effective manner.

Comment 21: Several commenters (17701, 17761, 17791, 17930, 19506, 19114) advocate flexibility in the implementation of the EGU MACT and other rules to avoid compromising the reliability of the electric system. These commenters believe the EPA should incorporate greater flexibility into the EGU MACT to ensure adverse impacts on the reliability of the electricity supply are avoided.

Response to Comments 19 - 21: There are several flexibilities in final rule that EPA wills help to avoid reliability issues. The regulation is applied facility wide so that facilities are able to average across units. Facilities also are able to average over time. They do not have to operate above the standard all the time but rather can meet the standard on a 30 day rolling average. There are alternative standard formats so that a plant can choose, for example, to meet a metals standard or a PM standard on either an input or output based level. In addition EPA is encouraging that permitting agencies be generous in offering the fourth year for installation of controls.

Comment 22: Commenter 17701 encourages the EPA to work with state and federal environmental regulators to examine all possible options to maintain system reliability and achieve health and environmental benefits while also ensuring reliability, minimizing capital costs to utilities, rate increases to consumers, and other avoidable economic impacts. The commenter offers the following suggestions:

> Allow utilities to coordinate the closure and/or retrofitting of existing electric generating units in an orderly manner that will ensure the continued supply of electricity and that will allow power generators to upgrade their facilities in the most cost effective way, while at the same time achieving attainable efficiency gains and environmental compliance; *and*
>
> Allow regulatory options for units that are necessary for grid reliability that commit to retire or repower; *and*
>
> Allow an EPA-directed phasing-in of the regulation requirements; *and*
>
> Establish interim progress standards that ensure generation units meet EPA regulations in an orderly, cost-effective manner.

Commenter 23: Commenters 18441 and 18448 request that the EPA state in the preamble to the final rule that the permitting authority should explicitly authorize or endorse the extensions to the 3 year compliance deadline for units which the RTO or relevant Reliability Coordinator indicates are "Reliability Critical Units." Commenter 18441 believes that Reliability Critical Units that have timely announced their deactivation should be eligible for a 1-year extension of the compliance obligation because deactivating a generating unit is simply another control option to comply with the final rule if the affected generating unit owner believes this is the least-cost compliance option, and is effectively no different from a generating unit choosing to install retrofits to meet the emissions rate standards that cannot get its retrofits in service by the January 1, 2015, compliance deadline. The commenter suggests that units choosing deactivation as a compliance option would only be granted an exemption if under the RTO's independent analysis, they are deemed critical to system reliability and are required to stay in service for a defined period until transmission or replacement resource solutions could be placed into service.

Response to Comments 22 - 23: The EPA expects that the fourth year for compliance will be broadly available to these plants that need it for the installation of controls or on site replacement capacity or, where reliability could be at risk, for transmission upgrades and construction of replacement capacity off site. This will allow facilities to plan for a well-coordinated compliance period.

Comment 24: Commenter 17868 desires that EPA take into account the numerous contingencies that could cause concern for reliability during the compliance period including multiple retirements, multiple outages, lack of generator response during a cold weather event, and revisions to the North American Electric Reliability Corporation's (NERC) Critical Infrastructure Protection (CIP) Standards.

Response to Comment 24: The EPA has indeed taken into account the wide array of contingencies that will prevent a facility from either retrofitting or closing within the compliance time frame. The EPA maintain that most, if not all, units will be able to comply with the requirements of this rule within 3 years. The EPA also believes that making it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in the range of situations described above, addresses many of the other concerns that commenters have raised. The EPA believes that the number of cases in which a unit is reliability critical and in which it is not possible to either install controls on the unit or mitigate the reliability issue through construction of new generation, transmission upgrades, or demand-side measures, within 4 years, is likely to be very small or nonexistent. None-the-less, where such cases appear EPA has authorities to manage these situations so that the maximum environmental protection can be achieved while facilities continue to come into compliance.

Comment 25: Commenter 17919 claims that analyses that have been submitted to the EPA showing that the rule does not cause a problem for electricity reliability, are "highly suspect" in that they are "largely from economic competitors with a vested economic interest in decreasing the economic viability of coal-fired generation and thereby increasing the clearing price of energy for consumers – that dispute adverse reliability claims from the proposed rule."

This commenter points instead to another analysis from the Federal Energy Regulatory estimating a large amount of coal-fired capacity 'likely' and "very likely" to retire. The commenter states that the EPA should utilize the flexibility afforded under the CAA to ease the compliance schedule set out by the proposed rule.

Response to Comment 25: The EPA makes no judgments about the motives of any of the commenters. The Federal Energy Regulatory Commission (FERC) report relied on here was a staff draft that was done before EPA had even proposed its regulations. It made assumptions about the stringency of the regulations that went well beyond what EPA actually proposed and final led. As such it has very little bearing on this rulemaking. Furthermore the FERC Chairman stated clearly that the study the commenter is referring to was a "back-of-the envelope first assessment of the amount and location of potential generator retirements. He further said that informal assessment of that kind cannot be relied upon to determine specific effects on system reliability. Therefore, it is inadequate to use as a basis for decision making."

None-the-less as stated elsewhere in this document, the CAA provides flexibility to address any reliability problems should any arise.

2. Current compliance period should be shorter.

Comment 26: Several commenters (15678, 16122, and 17846) ask the EPA to ensure that compliance occurs as soon as possible. Commenters 16122 and 17846 make note of the EPA's Trust Responsibility.

Comment 27: Commenter 17819 asserts that the 3 or 4 year implementation schedule for Hg control is not as expeditious as practicable. According to the commenter:

1. U.S. EPA asserted in 2000 that is appropriate and necessary to establish Hg emission standards for coal-fired EGUs. 65 FR 79825 (December 20, 2000).

2. By 2003, the DOE concluded ACI is an effective Hg control technology for coal-fired EGUs that requires minimal capital costs, is easily retrofitted and can achieve 90 percent removal efficiencies. See Durham, Michael et al. Full-Scale Evaluation of Mercury Control By Injecting Activated Carbon Upstream of ESPS. 2003. available at: www.netl.doe.gov/technologies/coalpower/ewr/mercury/control-tech/pubs/ A5-B2.pdf.

3. The DOE's findings about the effectiveness of ACl Hg control systems are consistent with the use of ACl in other industry sectors since the mid-1990's to meet MACT mandates. See 62 FR 48348 (September 15, 1997).

4. Coal-fired EGUs in Illinois and several other states are already subject to state-specific Hg emission standards and have demonstrated it is already practicable to retrofit effective Hg controls. See "State Local Mercury Toxics Program for Utilities" from the NACAA, available at \Vww.4cleanair.org; see also 35 Ill. Admin. Code § 225.230.

5. For its part, U.S. EPA's present regulatory proposal explicitly acknowledges that all Hg control options take significantly less than 3 years to install. Proposed Rule at 441-447.

6. U.S. EPA also estimates that the implementation of these controls will reduce cumulative Hg emissions from 29 tpy to 6 tpy. Id at 26 and 153. Each year that regulatory implementation is delayed will result in up to 23 tons of unnecessary emissions of Hg, a persistent, bioaccumulative and toxic substance.

7. ln light of the ready availability of Hg controls for coal-fired EGUs and the well established threat to human health and the environment posed by Hg emissions, U.S. EPA's compliance timeline is not as expeditious as practicable.

8. To comply with the CAA mandate for emission standards to be implemented as expeditiously as practicable, two commenters assert U.S. EPA must establish a more immediate deadline for implementation of Hg emission standards for coal-fired EGUs.

9. Under any circumstances, it is contrary to the plain language of the CAA and against the manifest weight of evidence to allow a 4-year compliance schedule for any coal-fired EGU.

On the other hand, commenter 17675 requests a 5-year compliance period for the Hg limits only. The commenter notes that this would be similar to the BACT status allowed under 40 CFR 63.6(i)(2)(ii).

Response to Comments 26 and 27: Several commenters suggested that 3 years was too long for a compliance period given the delays in promulgating this regulation, and urged EPA to require compliance in a shorter timeframe. Some of these commenters said that, consistent with EPA's Trust Responsibility the compliance period should be as short as possible. The EPA understands very well the importance of bringing facilities into compliance as soon as possible so that all Americans can realize the public health benefits of this rule without further delay. We agree that many plants will need fewer than 3 years to come into compliance and some already are in compliance. For other plants, coming into compliance will require substantial engineering and construction. The EPA finalized the 3-year compliance period for EGUs given the sheer number of sources that are in the category and that may have to install controls to comply with the final rule.

3. Current compliance dates are sufficient.

Comment 28: Multiple commenters (19536, 19537, 19538, 17110, 17402, 17648, 17808, 17854, 17870, 17973, 18025, 18027, 18421, 18425, 18438, 18439, 18450, 18487, 18501, 18541) ask that no additional time be granted for compliance.

Multiple commenters (19536, 19537, 19538, 16850, 17408, 17421, 17648) reference an April 2011 report entitled "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" where URS Corporation concludes not only that technology is readily available, but that the technology can typically be installed in less than 2 years.

Commenter 18421 states that based on that report, no additional controls would need to be installed in many cases and any coal unit should be able to comply with all of the standards. Commenter 17648 notes that utilities that failed to plan ahead "should not be permitted to use their own inaction to justify more time."

Commenters 17808 and 18450 note that several major utility companies have anticipated the EPA's rules and are already taking action to ensure a reliable supply of electricity in their service territory and beyond. Commenter 17808 cites two companies that have made planning efforts in advance of final rulemakings. The commenter cites one company (NextEra Energy) that began evaluating control technology before the release of the proposed rule. The commenter cites another company (Constellation Energy) that similarly conducted preliminary engineering studies before the Maryland Legislature enacted the Healthy Air Act of 2006.

Commenters 17648 and 18450 agree that there is significant excess generation capacity in the country and reliability will not be threatened by the rule.

Several commenters (18487, 19536, 19537, 19538) agree that the 3-year period will not adversely affect electricity system reliability.

Commenter 17110 urges the EPA to proceed with finalizing the rule without delay. According to the commenter, companies are already preparing for a 2015 compliance date, factoring in the capital expenditures required to comply and delays would undermine decisions that have already been made.

Commenters 17789 and 18450 agree that the compliance time is reasonable and further states that a shortage of skilled labor is unlikely to prevent utilities from meeting the compliance requirements.

Commenter 18421 notes that the Building and Construction Division of the AFL-CIO has stated that there is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development. According to the commenter, in fact, given the high levels of unemployment in the construction sector, these jobs are much needed.

Several commenters (17844, 18439, 18450) believe that the industry is well-positioned to comply in the time allotted without threatening electric system reliability. Commenters (17844, 18450) cite the following sources: two recent reports – one from M.J. Bradley & Associates and Susan Tierney of the Analysis Group, and the other from the Bipartisan Policy Center – that independently conclude that the electric industry is well-positioned to comply with the EPA's proposed air regulations without threatening electric system reliability. According to the commenters, if electric system reliability were to be threatened in local areas as a result of the rule, the EPA has the statutory authority to grant, on a case-by-case basis, extensions of time to complete the installation of pollution control systems.

The commenters assert that in addition, recent electricity forward capacity market auctions in the PJM and ISO-New England markets for the period of 2014 and 2015 indicate that the capacity markets cleared with electricity reserve margins of 20 percent in PJM and greater than 14.4 percent in ISO-New England. According to the commenters, these reserve margins are well in excess of the federal reliability standards set by the NERC for the year 2015, and these results cover periods after the rule is expected to have been in place for at least 6 months, demonstrating that the electric industry can meet the requirements of the rule without threatening the reliability of the electric system. Commenter 18450 quotes NERC, stating that NERC does not see impacts from the proposed climate legislations or anticipated EPA regulation as a reliability concern. Commenter 18450 cites a January 2011 report by Charles Rivers Associates (CRA) that concludes that (1) Less than 5 percent (35 GW) of the total capacity in the EIC will retire by 2015; and (2) Electric system reliability can be maintained while transitioning to a cleaner energy future through increasing operation of existing, underutilized gas plants, coal-to-gas conversions, new gas-fired generation, expansion of load management programs, and established market and regulatory safeguards.

Commenter 18541 notes the existence of a:

> broad array of electricity generation and grid management technologies that are making "baseload" power obsolete as FERC Chairman Wellinghoff noted in 2009. Indeed, a combination of renewable energy (such as wind, solar, biomass, geothermal, low-head hydro), natural gas and flexible generation technologies, and energy efficiency can now meet new electricity demand, and begin to replace or back out existing generation, within most balancing areas in the country. Such combinations of technologies, paired with smart grid management in balancing areas (including use of forecasting of output from wind and sun generation) can ensure a reliable electricity supply. The use of renewable energy and efficiency will also provide savings over time from reduced fuel use.

Commenter 17819 cites a 2003 DOE report evaluating Hg control by activated carbon:

> injection (ACI), stating that ACI has low cast, requires little downtime to install, is effective for bituminous and sub bituminous coals, can achieve 90 percent removal when

used with a fabric filter, can be integrated with virtually every configuration of air pollution control equipment including ESPs, fabric filters, wet and dry scrubbers.

Commenter 18425 states that the 1-year extension if the facility is unable to install appropriate controls will protect electricity system reliability. According to the commenter, applying the extension to both the installation of add-on controls and the construction of on-site replacement power is appropriate under the CAA.

Commenter 17928 supports the schedule and the agency's authority to extend the time allowed provided that any additional time granted does not provide an undue economic advantage.

Comment 29: Commenter 17648 asked that EPA establish uniform criteria for the section 112(i)(3)(B) case-by-case one-year extension and allow plants that receive the extension to dispatch only to meet reliability needs during the extension period.

Comment 30: Multiple commenters (17254, 17620, 17648, 17810, 17852, 17853, 18025, 18421, 18932) agree with the EPA's assessment that the new rules will not jeopardize or impair the reliability of the electricity supply. Other commenters (17254, 17648, 17810, 17852, 17853) cite reliability assessments that show sufficient capacity to ensure reliability of the electricity network after the rule takes effect. These include:

- North American Electric Reliability Corporation (NERC). 2010 Long-Term Reliability Assessment. October 2010. http://www.nerc.com/files/2010_LTRA_v2-.pdf
- Ira Shavel & Barclay Gibbs, Charles River Associates, "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT" (Dec. 16, 2010)
- Michael J. Bradley, Christopher E. Van Atten, & Amlan Saha (M.J. Bradley & Associates LLC) & Susan F. Tierney (Analysis Group), "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Summer 2011 Update," (June 2011)
- Susan F. Tierney & Charles Cicchetti, "The Results in Context: A Peer Review of EEI's 'Potential Impacts of Environmental Regulation on the U.S. Generation Fleet'" (May 2011).
- Integrated Planning Model data commissioned by America's Natural Gas Alliance (ANGA).
- Credit Suisse, *Growth from Subtraction: Impact of EPA Rules on Power Markets* (September 23, 2010), p. 45, available at http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=b42de70d---b814---4410---831d--- 34b180846a19.

Comment 31: Several commenters (17648, 17853, 18421) believe that the number of coal-fired EGU retirements that will result of regulation of EGUs have been overestimated by some sources. These commenters note that independent analyses support the EPA's retirement projections, and criticisms of the EPA's projections are overstated. Commenters note that EEI's report resulted in inflated unplanned coal retirements because their modeling scenarios incorrectly assumed that the Waxman-Markey climate change bill passed Congress, that the CWA section 316 cooling tower regulations would mandate a one-size-fits-all standard, and MACT limits that are more restrictive than those proposed in the Toxics Rule. Commenters also state that the Tierney-Cicchetti Peer Review Report found that only one of EEI's scenarios represented a plausible regulatory scenario, but determined that the incremental unplanned coal retirements modeled under this scenario for 2015 (totaling 24 GW) should be considered the upper end of potential retirement impacts, since even this scenario overstates the impacts of the section 316 rule. Commenter 18421 believes that the North American Electric Reliability Corporation (NERC)

"2010 Special Reliability Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations" may also overestimate the impact of new regulations.

Comment 32: Several commenters (17648, 17810, 17852) believe that existing gas units have significant untapped potential, which can be utilized to maintain reliability without the need to undertake new construction. Commenter 17648 notes that if all coal-fired units with a name plate capacity of less than 200 MW retired, the power produced by these retired units could be replaced using only 5% of the unused capacity of existing combined cycle gas units. Commenter 17810 notes that the existing natural gas-fired EGU capacity will allow the industry to maintain its reserve margins, including during the scheduled outages that will be necessary to install pollution control equipment required by this regulation.

Comment 33: Several commenters (17620, 17648, 17853, 17875, 18932) argue that EGUs will have sufficient time to comply with the rule without disrupting reliability. These commenters note that power plants have known about the various new regulations affecting power plants for several years and have therefore had plenty of time to prepare. These commenters note that many public utility commissions require integrated resources plans, which implement a planning mechanism to assure adequate reserve margins are maintained. Commenter 18932 notes that several utilities have made statements indicating that they are well positioned to comply with the EGU MACT, as well as other EPA regulations that will affect the utility sector.

Comment 34: Commenter 17620 points out that several states have implemented Hg limitations for EGUs without adverse impacts on reliability.

Comment 35: Several commenters (17110, 17810, 18025, 18421) note that forward capacity auctions, such as those held by PJM and ISO-New England for the years 2014 and 2015 (after the Transport Rule and this proposed rule will be in effect), have shown that the regions will have more than enough capacity to meet federal reliability standards without significant price increases.

Comment 36: Several commenters (17648, 17810, 17853, 18025) believe that retirements that occur can be managed and new capacity can be developed to ensure no disruption to the electric power supply after the rule is implemented. These commenters note that a number of practical and legal options exist for when an EGU is to be retired or needs greater time to install controls. Commenters further note that a resolution that maintains reliability can be reached through the authority under the Federal Power Act, or through exercise of enforcement discretion in a consent order to decree that accommodates both environmental imperatives and reliability concerns. Commenter 17648 points out that if reliable electric power is compromised by compliance with environmental regulations, the U.S. DOE, the EPA, state agencies, and regional transmission organizations (RTOs) can work together to strike a balance in protecting public interest in both objectives. Commenter 17648 also notes that RTOs typically have advanced warning of proposed unit retirements and that each RTO has procedures to assure that threats to reliability are identified early enough to be avoided.

Comment 37: Commenter 17810 notes that the EPA can grant time extensions for power plants to install pollution control equipment on a case-by-case basis under the CAA. This commenter further notes that the EPA and the DOE have the authority to enter into administrative orders of consent or consent decrees with power plants that allow them to run under specific and limited circumstances to maintain reliability. The commenter states that the DOE can override CAA requirements under section 202(c) of the Federal Power Act in limited emergency circumstances, and if a widespread reliability concern were to arise that could not be addressed through these statutory mechanisms, the President also has the authority under the CAA to extend deadlines in the rule if technologies are not available and it is in the national security interest.

Comment 38: Commenter 18039 questions the suggestion that existing units be allowed to run for an additional year while a replacement is constructed, without being subject to MACT standards for that year. The commenter agrees that this is a reasonable scenario for facilities that will use that year to construct a replacement unit with significant long-term emission reductions. However, the commenter is concerned that a facility in the process of building replacement power may decide to operate a high-emitting unit for an additional year, specifically due to the extension. The commenter therefore objects to the extension, for fear a large amount of pollutants will result. The commenter also asks that if construction replacement power lasts longer than the one-year extension, the final rule wording make clear that the older unit is not permitted to avoid MACT compliance beyond that year, even if the replacement is not yet on-line.

Comment 39: Commenter 18421 called on the EPA, the Department of Energy, and the Federal Energy Regulatory Commission to expand and accelerate interaction with regional utility planning and operation centers, the National Association of Regulatory Utility Commissions, state PUCs, and all market participants to ensure that the measures available to preserve electric system reliability while providing for life-saving reductions of Air Toxics are implemented.

Commenter 19114 states that EPA notes that before the final rule, they will work with "DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC" to protect reliability. According to the commenter, this language suggests that EPA has not consulted with DOE and FERC to date, which suggests that the necessary rule coordination or harmonization is not occurring. The commenter states that the statement implies that EPA only sees flexibility on the part of DOE and FERC to protect reliability and that adding this flexibility into the MACT rule itself, or other proposed rules for that matter, is not a concern for EPA, which goes directly against the Executive Order.

The commenter states that it has been involved in a series of meetings with PJM, SPP, EPA, DOE, FERC, and NERC to discuss the impacts of this and other EPA rulemakings on the reliability of the transmission system as well as to discuss ways that EPA can provide flexibility to ensure reliability. The commenter suggests that EPA closely examine all of the publicly announced implementation plans from utilities to assess the accuracy of the data EPA is relying on to make the claim that grid reliability is not an issue. According to the commenter, these data must take into account actual and planned future regulations and their impact on the electric sector, as well as resulting rate and reliability impacts, and only in viewing a comprehensive and holistic analysis of the electric sector can there be a reasonable discussion of the reliability impacts. The commenter states that this type of cross-functional analysis should include the most specific localized or unit level reliability analysis possible in order to pick up key ancillary services important to grid stability.

Response to Comment 28 - 39: The EPA has set out in the preamble to this rule, the situations that merit the one-year extension under CAA section 112(i)(3)(B). While authority to grant the 1-year extension is given to the state permitting authorities, EPA expects that that discussion in the preamble will help guide the states on this matter.

While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that when appropriate it will be broadly available to facilities. Please see the preamble for a fuller discussion of the 1-year extension.

4. Current compliance period should be longer.

Comment 40: Numerous commenters (18023, 8443, 9738, 16705, 16469, 16849, 16856, 17022, 17055, 17254, 17265, 17297, 17368, 17383, 17400, 17402, 17403, 17406, 17608, 17623, 17627, 17637, 17638, 17640, 17648, 17654, 17655, 17656, 17675, 17677, 17681, 17689, 17696, 17697, 17703, 17705, 17707, 17711, 17714, 17716, 17720, 17722, 17724, 17730, 17731, 17732, 17734, 17735, 17736, 17741, 17752, 17756, 17758, 17761, 17765, 17767, 17770, 17774, 17775, 17790, 17798, 17799, 17800, 17805, 17807, 17808, 17810, 17812, 17813, 17815, 17817, 17820, 17821, 17824, 17829, 17834, 17837, 17840, 17857, 17868, 17870, 17873, 17876, 17877, 17878, 17879, 17881, 17883, 17885, 17887, 17902, 17904, 17909, 17911, 17912, 17913, 17918, 17925, 17930, 17931, 18016, 18021, 18024, 18026, 18027, 18031, 18037, 18038, 18419, 18422, 18424, 18428, 18430, 18433, 18437, 18440, 18441, 18447, 18477, 18498, 18500, 18502, 18575, 18933, 19032, 19114, 19121, 19212, 19213, 19506, 19653) state that the compliance period is too short.

Several commenters (8443, 9738, 17608) ask that small entities be granted additional compliance time.

Multiple commenters (16469, 16705, 16849, 17265, 17400, 17637, 17655, 17656, 17703, 17730, 17758, 17776, 17913, 18038, 18437, 18447, 18477, 18498) advocate for an optional extension for 2 more years, resulting in a total of 5 years. Several commenters (18575, 19032, 19213) request that the EPA allow a total of 5 years for compliance.

Multiple commenters (18023, 17623, 17689, 17714, 17722, 17731, 17732, 17756, 17775, 17817 (major sources of HAP), 17868, 17904, 17925) request that the EPA allow a total of 6 years for compliance.

Multiple commenters (17022, 17408, 17735, 17758, 17761, 17817 (non-major sources of HAP)) ask that the timeframe be extended until 2020.

Several commenters (17724, 17741, 17805, 17868) ask that a compliance timeline of 9 years be permitted.

Multiple commenters (17055, 17408, 17677, 17734, 17756, 17761, 17774, 17791, 18024, 18026, 18422, 19506) ask that the EPA consider a flexible, gradual, or staggered compliance schedule for this rulemaking.

Commenter 17911 requests a 2-year extension on compliance with some provision for further extension for local utilities, based on the utilities' additional burden of maintaining a publicly accountable process. The commenter requests provision for further extension provided that the local utility can document that they have pursued a good faith effort to expeditiously secure approvals, financing, engineering, design, manufacturing, acquisition and installation of the necessary emission control equipment.

Commenter 18441 states that outage windows to accommodate upgrade construction are limited to opportunities when prevailing system conditions permit, so that operational reliability is not compromised. The commenter appreciates the EPA's recognition of the need to spread complex outages over multiple outage periods. According to the commenter, as the breadth of the outages and the availability of retrofit materials may impact the scheduling of outages, it is not clear that the proposed 3+1 timeline provides sufficient flexibility for the commenter, as a regional transmission organization to manage all of these outages in a staggered manner.

Commenters 18441 and 18448 state that timely notice of deactivation to the regional transmission organization and an identification that the unit in question is a reliability critical unit which cannot be replaced with alternative resources or transmission reinforcements in the 4-year time allotted would be allowed a limited "safe harbor" from penalties until the regional transmission organization indicates that adequate resources have been put in place to address the reliability concern. The commenter states that the regional transmission organization's findings would be developed in open stakeholder processes and made available for the EPA's (or state air permitting authority's) ultimate determination as to whether to grant such an extension and that such a process may entail the EPA authorizing or endorsing a schedule of compliance in the affected generating unit's Title V permit through the implementing state authority, in coordination with the regional transmission organization; and/or a Consent Decree between the EPA, the state authority and the generation owner developed and signed prior to the end of the compliance period, or a formal extension through a streamlined process including the EPA, and the implementing state authority working with the asset owner and the regional transmission organization to grant extensions beyond January 1, 2016.

Multiple commenters (16469, 16850, 17608, 17640, 17705, 17711, 17716, 17719, 17724, 17730, 17752, 17756, 17761, 17774, 17805, 17820, 17821, 17837, 17840, 17868, 17902, 17918, 17919, 17931, 18016, 18033, 18037, 18422, 18428, 18440, 18442, 18498, 18575, 19506) ask that the EPA consider other simultaneous rulemakings and extend the compliance period. Commenters specifically mentioned the following:

a. Cooling Tower Intake Structures (17724, 17805, 17868, 17918, 17919, 18440, 18442)
b. Coal Combustion Residuals (17724, 17774, 17805, 17821, 17868, 17918, 17919, 18440, 18442)
c. Regional Haze (17719, 17724, 17730, 17761, 17805, 18442)
d. Clean Air Transport Rule (17608, 17724, 17868)
e. Water Effluent Limit Reductions (17724, 17774, 17805, 17919)
f. Cross State Air Pollution Rule (16850, 17640, 17705, 17716, 17730, 17752, 17756, 17761, 17774, 17820, 17821, 18442, 18498, 19506)
g. NESHAP for industrial, commercial and institutional boilers (16469, 17608, 17711, 17756, 17837, 17840, 18024, 18424, 18442)
h. NESHAP for commercial and industrial solid waste incinerators (17608, 18024)
i. NSPS for greenhouse gas emissions from EGUs (17608, 17774, 17918, 17919, 18440, 18442, 18498)
j. NAAQS for SO2, NO2, ozone, and PM (17821, 17918, 17919, 18440, 19506)
k. Area source Boiler MACT (18024)

Multiple commenters cite previous compliance timeline extensions that were granted:

a. Marine Tank Vessels - 1 year (18023, 16469, 17254, 17368, 17403, 17623, 17681, 17696, 17734, 17758, 17775, 17837, 17840, 17857, 17902, 17931, 18033)
b. Pulp and Paper Production - 8 years (17623, 17774)
c. MON (17623, 17774)
d. NESHAP for Secondary Lead Smelting - 1 year (17716, 17731)

Multiple commenters (8443, 17402, 17627, 17767, 17821, 17868, 18021, 18037, 18502) ask that the EPA consider physical space limitations. According to the commenters, without sufficient space to install control devices, units may have to be retired.

Commenter 18575 discusses its diverse generation portfolio and says that this usually mitigates price fluctuations related to the cost of generation of any single resource. However, the commenter says that this diversity now guarantees that it will be affected by several of the new and pending EPA rules all in the same timeframe, which will strain their ability to afford and meet compliance timelines. The commenter gives the following examples:

1. EGU MACT: As proposed, the commenter's coal-fired generation will be covered by the proposed EGU MACT;
2. RICE Rule: commenter's contracted generation from gas-fired, reciprocating internal combustion units are covered under the EPA's recent RICE Rule;
3. CSAPR: Commenter's Whelan Energy Center unit is covered by the CSAPR (formerly known as the "Clean Air Transport Rule");
4. CCR Rule: Commenter's coal-fired resources face compliance requirements related to the disposal of coal combustion residuals from coal-fired power plants to be finalized by the EPA in 2012;
5. GHG Rule: Commenter's facilities face restrictions under the upcoming NSPS for GHG emissions from new and existing EGUs that are scheduled to be proposed in September of 2011 and finalized by May 2012;
6. 316(b): On April 20, 2011, the EPA proposed its section 316(b) rule under the CWA that will require changes in cooling water intake structures used to cool coal, gas and nuclear steam-electric generating plants, including the Cooper Nuclear Station which forms a portion of the commenter's generation portfolio.
7. Regional Haze Rule: Commenter's Laramie River Station facility, located in Wyoming, faces additional regulatory costs since the state's SIP is still under review and could face new, potentially very expensive retrofit requirements to be completed by 2013, according to the EPA's Regional Haze timeline.

Commenter 17911 asks that the EPA consider the unintended consequences of recommending technologies that make CCR more difficult to recycle. The commenter suggests a 2-year moratorium on implementation of the proposed rule until some of the interrelated rules are more fully defined.

Response to Comment 40: In this regulation the EPA provided the maximum 3-year compliance time authorized under the statute. *See* section 112(i)(3)(A). Furthermore, the EPA's actions in other CAA section 112 rulemaking actions authorizing longer compliance periods are no longer relevant. Since those rules were issued, the D.C. Circuit Court has determined that the EPA does not have authority to provide a compliance period in excess of 3 years. *See NRDC v. EPA*, 489 F.3d 1364, 1373-74 (D.C. Cir. 2007) (rejecting a 1-year extension for all sources in the category because of changes to reporting requirements issued after the final rule setting forth the emission standards were initially promulgated too short). However as discussed elsewhere in this document and much more fully in the preamble, the permitting authorities do have authority to grant a 1-year extension under a range of circumstances. Beyond that the CAA provides mechanisms for sources to come into compliance while maintaining electric reliability.

The following is a response to the various reasons given in comments as to why the proposed compliance time frame is too short. For a fuller discussion of these issues please see the Technical Support Document entitled, "An Assessment of the Feasibility of Retrofits for the Toxics Rule" in the docket.

Claims of Infeasibility for 2015-16 Compliance

The EPA's authority for setting the compliance time frames is set out in the CAA. In developing this proposed rule, the EPA has performed specific analysis to assess the feasibility (e.g., ability of companies to install the required controls within the compliance time-frame) and potential impact of the proposed rule on reliability. For that analysis entitled "An Assessment of the Feasibility of Retrofits for the Toxics Rule" dated March 9, 2011, the EPA has projected the quantity of each APC technology that may need to be newly retrofitted and in service by the compliance date(s). The EPA used its IPM model to analyze which APC technologies would likely be used, and in what quantities, to achieve compliance with the proposed Toxics Rule.

The EPA's assessment shows that a reasonable, moderately paced effort of the power sector and supporting industry, including some early starts, would result in many of the needed retrofits being installed by January 2015 with some needing up to an additional year. In order for all retrofits to be completed by January 2015, most projects would have to start early and the sector would have to engage in a more aggressive deployment program. In the event that individual projects cannot be completed by the January 2015 statutory deadline for compliance, the CAA offers affected sources the opportunity to apply for a 1-year extension.

Claims That More Time is Needed for Small Entities To Comply

As stated above, the EPA's authority to provide more than three years to comply with the standards is constrained by CAA section 112(i)(3)(A) and the D.C. Circuit Court interpretation of that provision. *See NRDC v. EPA*, 489 F.3d 1364, 1373-74 (D.C. Cir. 2007) (rejecting a 1-year extension for all sources in the category after the agency promulgated changes to reporting requirements issued after the final rule setting forth the emission standards). The compliance provisions of the statute do not provide an exception for small entities.

Inadequate Labor Pool, Low Skill Level & Insufficient Equipment Suppliers

With current unemployment rates, sufficient quantities of engineers and skilled craft exist for implementation of this rule. Likewise, for the extreme case of local labor shortages (which is not anticipated), this challenge can be overcome by instituting a workforce development action plan during project execution. This sector's equipment suppliers and manufacturers are underutilized and have been since 2010.

Site Congestion Can Lengthen Retrofit Timing and lead to retirement

One commenter suggested that the facilities that were easy to retrofit, did retrofit for compliance with the acid rain program and CAIR. So what is left to retrofit under this program, is more difficult and will take longer than retrofits in the past. Several commenters said that plants may retire because space constraints would prohibit retrofitting.

Available space is a problem at many remaining facilities. Space constraints are a challenge that must be addressed early in the design stage of a compliance strategy. There are a number of ways to economize the available space but ultimately each plant is different and the solutions will be different. Many of the controls that the EPA expects plants to use to comply with MATS, especially DSI and ACI, work well at a space constrained facility. In addition, the EPA expects that in many cases it will be possible and economic to combine emissions from several units into a larger control device. In such combined multi-unit cases the installation time should be only slightly greater than for a single unit, and still feasible for compliance by 2015-2016. In any event, a multi-unit retrofit on one site has significant execution cost and schedule advantages not realized at multiple single unit stations through aggregating resources to create economies of scale. These include one-time mobilization, extended equipment rental, dedicated staging area, efficient skilled craft utilization, and reduced administrative outlays. Furthermore, units can be "tied-in" sequentially, avoiding a complete station shutdown during installation.

Successful examples include Dickerson Station's three 190 MW units feed a single scrubber which discharges into a single flue stack. Chalk Point station's two units share a single common wet FGD. FirstEnergy's Sammis station's wet scrubber project combined emissions from seven units into three absorbers. AEP's Clifty Creek and Kyger Creek stations will employ similar design concepts for their wet FGDs. And at WE Energies' Presque Isle facility several units are tied into one fabric filter.

Finally the rule allows facility averaging for existing EGUs in the same subcategory so that in many cases it may be possible to retrofit only some of the units and achieve the standards.

Time frame for Compliance Is Too Short to Construct and Permit an FGD Landfill

The compliance deadline allows sufficient time for completing landfills for FGD solids disposal. For example, DP&L will construct a landfill within 18 months to accept wastes generated from Stuart and Killen stations scrubbers. The EPA notes, however, that retrofitting units do not necessarily need to complete landfill construction ahead of commencing operation of the retrofit to achieve cost-effective emission reductions under the Transport Rule programs. Such a source may either utilize a completed portion of the newly permitted landfill under construction, transfer waste off-site to a permitted landfill within the owner's fleet, or contract waste removal (and disposal) services. For example, Dallman station subcontracts coal ash disposal at a local abandoned mine. The EPA uses a disposal cost assumption of $30-$50 per ton for wet FGD, dry FGD, and DSI controls, which the EPA developed in consultation with an experienced power sector engineering firm.

Short Time Frame Will Cause Electricity Rates to Rise

The EPA recognizes that this rule will cause electricity prices to rise. The EPA projects that the increase in retail electricity prices that will result from this regulation range from 2 to 3 cents per kWh in 2015 and will decrease in the ensuing years. On average, this is a 2.9 percent increase and is well below electricity prices seen historically and as recently as four or 5 years ago. The average increase over the base case declines over time.

Multiple Rulemakings Necessitate a Longer Compliance Time

A number of commenters said that the unusual number of regulations that the EPA is promulgating for the electric power sector in approximately the same time frame compounds the problems caused by the MATS compliance time. The EPA understands that there are a number of regulations that will set in place standards that have to be met by this industry. The Cross-State Air Pollution Rule was promulgated last summer and the Cooling Water Intake Rule will be promulgated next year. A regulation setting standards for handling coal combustion waste has been under development for the past few years. The confluence of these regulations allows the power industry to plan for compliance with information about the full suite of requirements that they will face. It reduces uncertainty and provides an opportunity for the power sector to develop integrated strategies for meeting EPA regulations allowing for a cost effective approach on the part of the companies that takes account of the multiple requirements. Many of these strategies will take advantage of the collateral effect of pollution control technologies. For example, actions taken to reduce emissions under the Cross-State Rule will help facilities achieve the acid gas and in many cases mercury standards in this rule.

Smaller Plants Will Not be Able to Compete with Larger Plants for Controls

Some commenters said that smaller plants would have a harder time getting controls on plants within the compliance time frame because they would not be able to compete with larger plants for equipment, labor, and engineering and therefore they need a longer compliance time frame. Small plants are not necessarily at a disadvantage. The EPA notes that smaller plants can often control very cost effectively either because they simply need less equipment and labor to retrofit and because they can often tie more than one small or midsize unit into one control device. Shared APC systems will allow the overall effort to be more manageable than otherwise, and should require relatively fewer supply chain resources.

Smaller Companies Will Not be Able to Compete with Larger Companies for Controls

Several commenters said that small companies need more time to comply with the regulation because they would not be able to compete with larger companies in the market for labor, equipment and engineering services to comply with this regulation. This comment presumes that there is a shortage of equipment, labor and materials to apply to compliance with this regulation. As stated elsewhere we are in an economy that is characterized by high unemployment and chronic excess capacity. While this regulation will modestly spur demand it cannot reasonably be expected stimulate enough demand to cause shortages such that firms will have difficulty obtaining the services they need to comply.

Comment 41: Multiple commenters offer suggestions on methods for allowing more time for compliance:

a. Authority under section 112(n)(1)(A): (17403, 17799).

b. State authority under section 112(i)(3): (18023, 9738, 16469, 17265, 17297, 17402, 17403, 17623, 17638, 17648, 17654, 17681, 17689, 17696, 17705, 17714, 17716, 17722, 17724, 17752, 17756, 17758, 17765, 17775, 17790, 17798, 17799, 17800, 17805, 17807, 17808, 17810, 17817, 17820, 17837, 17841, 17857, 17868, 17870, 17876, 17877, 17886, 17887, 18034, 18038, 18502, 18575)

c. Presidential authority under section 112(i)(4): (18023, 16469, 16705, 16849, 17265, 17400, 17637, 17655, 17656, 17681, 17689, 17703, 17705, 17714, 17722, 17724 (5-year exemption), 17730, 17756, 17758, 17774, 17775, 17799, 17805 (5-year exemption), 17807, 17817, 17820, 17821, 17868, 17870, 17876 (5-year exemption), 17877, 17886, 17931, 18027, 18031, 18033, 18034, 18038, 18428, 18477, 18500, 18502, 18575)

d. Categorical extension for publicly-owned or governmental facilities according to EO 13132, 13563, and UMRA of 1995: (17868)

e. State-designed programs under the delegation provisions of section 112: (17719, 17873)

f. Delay Consent Decree: (17654, 17876, 17930)

g. Through Administrative Orders of Consent (AOCs): (17808, 17868, 17870)

h. Through Consent Decrees: (17648, 17808, 17870, 18448)

i. Temporary waiver mechanisms: (17055)

j. Adoption of MACT compliance schedules through minor permit modifications of a source's Title V federal operating permits: (17868, 18422)

k. Compliance extensions for units that reduce early or install specified control equipment: (17265, 17638, 17681, 17807)

l. CAA section 112(i)(6): (17821; although the commenter argues that it offers no meaningful relief to most sources)

m. Provide a future effective date for the rule. This approach would allow promulgation by the date mandated by the consent decree, and would assist states and utilities by relieving the requirements of case-by-case MACT determinations that must be made until the MACT standard is promulgated: (18442)

Commenters 17648 and 18502 ask that the EPA allow use of consent agreements. Commenter 17648 states that as a matter of law and long-standing administrative practice, then, the requirements of the Toxics Rule will apply without abatement to facilities subject to a consent arrangement, however, as a matter of policy, the EPA may wish to accommodate certain consent arrangements that pre-date publication of the proposed Toxics Rule in case-specific circumstances. Commenter 17648 explains that most existing consent arrangements are directed to controls on criteria pollutants which will ordinarily be insufficient to control HAP in a manner consistent with the rule. Commenter 17648 states that any accommodation would need to provide for the implementation of HAP controls "as soon as practicable" given existing commitments under the consent arrangement. According to the commenters, for example, a consent arrangement that provides for installation during 2015 of a FGD system that would adequately control acid gas HAP might be accommodated provided controls for Hg and non-Hg metal HAP were installed prior to the compliance deadline.

Commenter 17648 suggests two options for accommodating consent arrangements:

1. First, the EPA could authorize state permitting agencies to provide facilities subject to a consent arrangement with the same 1-year extension from the applicable statutory deadline "for the installation of controls" under section 112(i)(3)(B) available to other sources, assuming those facilities intend to install controls before the end of 2015. According to the commenter, the EPA could exercise its discretion as to whether to require facilities subject to a consent arrangement to comply with interim operating conditions.

2. The second option available to the EPA is to enter into a "wrap-around" consent order or consent decree that would incorporate additional requirements necessary to comply with the Toxics Rule beyond those required in the existing consent arrangement. The commenter states that this task must be approached on a case-by-case basis, with the judicious use of the enforcement discretion by the EPA and state permitting agencies and that existing consent arrangements are unlikely to provide for the installation of emission controls sufficient to comply with the Toxics Rule. The commenter asserts that EGU operators who are parties to such arrangements will bear the burden of deciding whether to seek additional relief, or to comply with the rule on time. The commenter states that some consent arrangements will be inadequate in scope or alacrity, or both, and will need to be supplemented either by a "wrap-around" consent order or decree, or by an amendment to the existing arrangement. According to the commenter, ultimately the same enforcement discretion that formed the basis of the existing consent arrangements will be applied to determine if, and how, they must be modified, and the operating conditions that should be applied during the period of extension. The commenter states that only in this

way can the EPA and state permitting agencies conserve the benefits of these consent arrangements without sacrificing the overwhelming health and economic benefits that the Toxics Rule will provide.

Response to Comment 41: The agency has provided the maximum time authorized under CAA section 112(i)(3)(A), and the provisions cited by commenters do not alter our authority concerning the initial compliance time that may be provided in CAA section 112 standards. Furthermore, as the EPA stated in the preamble to the final rule, our analysis shows that most plants can meet the standards within the 3-year timeframe. The EPA believes that although most units will be able to fully comply within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. That fourth year should be broadly available.. Furthermore, in the event that an isolated localized reliability concern was to emerge that could not be addressed solely though the 1-year extension under CAA section 112(i)(3), the CAA from provides some flexibility to assure reliability is maintained while facilities come into compliance.

Comment 42: Multiple commenters (18023, 16469, 17254, 17297, 17383, 17403, 17623, 17638, 17654, 17681, 17696, 17705, 17716, 17718, 17720, 17722, 17724, 17731, 17734, 17752, 17765, 17774, 17775, 17790, 17798, 17799, 17800, 17807, 17816, 17820, 17840, 17842, 17856, 17857, 17868, 17876, 17881, 17886, 17902, 17931, 18016, 18021, 18031, 18033, 18034, 18424, 18428, 18500) request a "blanket 1-year extension" of the compliance deadline.

On the other hand, multiple commenters (9738, 17265, 17402, 17648, 17701, 17758, 17808, 17810, 17852, 17887, 17973, 18025, 18027, 18438) ask that requests be granted only on a case-by-case basis.

Response to Comment 42: CAA section 112(i)(3)(B) provides that "[t]he Administrator (or a State with a program approved under subchapter V of this chapter) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) of this section if such additional period is necessary for the installation of controls." This provision on its face applies to individual sources and, furthermore, the D.C. Circuit Court has determined that EPA does not have authority to provide a compliance period in excess of three. *See NRDC v. EPA*, 489 F.3d 1364, 1373-74 (D.C. Cir. 2007) (rejecting a one year extension for all sources in the category after the Agency promulgated changes to reporting requirements issued after the final rule setting forth the emission standards). Some industry commenters have specifically stated that they will be able to comply with the rule in the 3 year period and we believe that there are approximately 69 EGUs that appear to be currently complying with all of the existing source standards. We do not think it would be reasonable or consistent with the statute to provide a longer compliance period for sources currently complying and sources that can in fact comply within 3 years. For sources that cannot comply in that time, the 1 year compliance extension is available and EPA has committed to working with sources to ensure that compliance with the final rule will not affect electric reliability.

Comment 43: Multiple commenters (16824, 17003, 17137, 17730, 18441) ask that compliance be delayed until additional studies or analyses are conducted.

Commenter 16824 asks that the EPA complete a cost-benefit analysis (with further peer review and additional opportunity for public comment) before implementing this rule.

Commenters 17137 and 17821 endorse an indefinite delay until further study can be undertaken on the costs and impacts to industry, jobs, and consumers along with additional testing and evaluation. According to commenter 17137, the current deadline meets neither "the test of reasonability nor realism."

Commenters 17003 and 17730 ask that the EPA undertake a formal assessment of the feasibility for regulated sources to contract for equipment and manpower needed to meet compliance deadlines for the Utility MACT and other pending regulations affecting coal-fired power generation.

Commenter 17003 asks that the EPA allow that a trial be undertaken to prove EPA's assumption that acid gas can be removed at low cost.

Commenter 17821 asserts that non-Hg metallic HAP removal technologies need further study in the same way that the DOE studied Hg.

Commenter 18441 states that full impact of the rule and the resulting generator decisions on whether to comply or retire have not been made. According to the commenter, it is simply premature to reach a definitive conclusion that the rule can be met without adversely impacting electric reliability. The commenter states that although the EPA's analysis addresses overall system adequacy, the EPA has not analyzed system security under the rule.

Response to Comment 43: The MATS was developed by the EPA after years of studies and data analysis that examined the nature and quantity of HAP emissions from power plants, the health and environmental effects of the pollution, the availability of pollution controls and other measures to reduce emissions of these pollutants, the costs and benefits of reducing HAP emissions from EGUs, and the effect of the rule on consumers and on jobs. What the EPA learned is that coal-fired and oil-fired power plants are very large emitters of these pollutants, that cost effective strategies to reduce these emissions are readily available, and that doing so, while expensive would provide public health benefits valued at many times the cost, including avoiding premature deaths, more aggravated asthma and other respiratory problems, non-fatal heart attacks, missed work and school days In the process the rule has little impact on consumer prices and increases jobs moderately.

Although one can always argue for more studies, delaying this rule now for the purpose of more studies would delay significant health benefits to hundreds of thousands of Americans.

Comment 44: Commenter 17682 worries that the rule as proposed will severely harm the ability of the United States to produce reasonably priced power, diminish its international competitiveness, and result in minimal environmental improvements, and that it could even result in increased environmental risks from alternative energy sources, This commenter requested that the EPA withdraw the proposed rule. Commenter further asks that the EPA reissue a new rule only if it reflects the results of a credible cost-benefit analysis and a full assessment of the impacts of using potentially conflicting and relatively untested MACT technologies to achieve compliance with the range of pollutant standards

Commenters 17003 and 17297 quote the EPA compliance cost estimates of a $3-4 increase in consumer electricity costs and suggest that a longer compliance timeline to develop and implement the least cost compliance strategy to ensure a reliable electric supply and minimal rate impacts.

Response to Comment 44: The impact of this rule on electricity and natural gas prices are within the range of normal variability and well below levels seen only 2 or 3 years ago. It is not reasonable to take as a "given" that this rule will diminish international competitiveness. In fact the annual cost of the rule is less than 0.001 percent of GDP. It is unlikely to have much impact on the competitiveness of the U.S. economy.

The benefits of the rule on the other hand, according to the EPA's cost benefit study which is based on peer reviewed scientific literature and methodologies are far greater than the costs, providing significant public health improvements to Americans. Furthermore this regulation can be complied with using tested control technologies that are in use on coal-fired plants today.

Comment 45: Multiple commenters (18023, 16850, 17402, 17403, 17623, 17648, 17655, 17686, 17705, 17736, 17757, 17758, 17800, 17805, 17840, 17873, 19114) offer opinions on the timelines for control equipment installation. Commenter 19114 provides a detailed discussion of time frames for planning, permitting and construction of controls in their comments.

a. DSI:

(1) 9-18 months on average but up to 5 years recently (17758)
(2) Two years (17402)
(3) <12 months (17648)

b. ACI: Up to 2 years for optimization after installation (17402)

c. FGD:

(1) Up to 60 months (17758)
(2) 40-69 months (18023)
(3) 36-42 months (17402)
(4) 40–60 months (17705)
(5) 40-65 months (17403)
(6) 52 months (17736, 19114)
(7) 44-64 months (17800)
(8) 66-72 months (17873)
(9) 2-4 years (16850)
(10) 40-65 months (17799)
(11) 52 months (17821)
(12) 50-63 months (17886)

d. FGD-associated landfill:

(1) 54 months on average (17736, 18428, 19114)
(2) > 10 months (19114)
(3) 3-5 years for permitting (17800)

e. Baghouse:

(1) 12-24 months (18421)
(2) >36 months (18023, 19114)
(3) >4 years for retrofit (17805)

f. SCR:

(1) 36 months (1837)
(2) 3 ½ years (17623, 18428)

(3) 43 months (17655)
(4) 42 months (17736)

g. Scrubber:

(1) > 36 months (19114)
(2) 40-60 months (17623)
(3) 40-69 months, average of 50 months (18023)
(4) 4-5 year time frame (17757)
(5) 4-5 years (17736)
(6) 48-54 months (17840)
(7) 2-3 years (16850)
(8) 52-58 months (17627, 18037)
(9) 3-5 years (17817)
(10) 45-58 months (17820)

h. New generation: 6 years (18023)

i. Changes in fuel supply to natural gas: 4 ½ years (18023)

j. Changes to transmission grid:

(1) >3 years (18023)
(2) up to 7 years (17886)

k. Fabric filter:

(1) 42 months (17736, 17821)
(2) 5.5 years (17840)
(3) >=36 months (17868)

l. DSI with baghouse: 50+ months (17886)

Commenter 17868 notes that the EPA's assumption of faster retrofits is probably incorrect.

Response to Comment 45: Numerous commenters submitted their own evaluation of the length of time required to install controls, switch fuels, and upgrade the grid, some of it based on their own experience from the past. Numerous commenters claimed that actual project execution timeframes exceeded the time allotted by the proposed rule. To illustrate the point, some commenters referenced specific retrofit project elements with asserted time requirements for their completion as part of the retrofitting process.

The EPA does not agree with commenters that lengthy retrofit schedules from various individual prior projects are dispositive of the power sector's ability to install cost-effective retrofits under the MATS schedule. Project schedule length is heavily influenced by resource dedication and execution method. While any project can be executed at a slow pace, the EGU pollution controls industry developed into a mature industry in response to the Acid Rain Program, the NO_X SIP Call, and CAIR with the ability to perform accelerated project execution using a faster and more efficient Design-Build process. The power sector has realized considerable efficiency gains through integrating standardized equipment designs, systems approach, and modular construction techniques as well as the formation of business alliances1 to reduce frictional time lags.

A typical control retrofit project consists of the following elements, several of which may occur simultaneously: site studies, conceptual engineering, equipment sizing, and cost estimating, planning, detailed design, procurement, construction, commissioning/testing, and permit application. For design-build methodology, the project is divided into two major phases: pre-award work requiring minor expenditures (site studies, conceptual engineering, equipment sizing, cost estimates, schedule planning) and award work requiring significant capital commitment (detailed design, procurement, construction, commissioning/testing).

Pre-award work elements are typically executed sequentially since each preceding stage's results inform the following stage; however, award work elements can be executed with "Lean Construction" techniques to shorten time frames. Since a typical emission control device is a combination of, rail car unloading, waste water treatment, and dewatering facility occupy different plant site locations; thereby, allowing simultaneous design, procurement, construction, and testing activities. To illustrate the point, Asheville Power station FGD retrofit was completed on a 26 month schedule. Constellation's FGD, fabric filter, and activated carbon retrofit was completed in 29 months from notice to proceed. Presque Isle's 3-unit fabric retrofit was completed in approximately 2 years.

The examples cited by commenters fail to account for the adoption of proven faster execution methods evidenced by numerous units that have demonstrated FGD retrofit project completion in less than 30 months. In particular, commenters who cite examples of lengthy or delayed retrofit schedules from projects conducted during the highly uncertain period of the CAIR remand (when it was prudent to proceed cautiously) cannot reasonably expect such experiences to apply to retrofit project execution with the benefit of renewed regulatory certainty gained by promulgation of the final MATS rule (when it is prudent to proceed expeditiously and with confidence).

Evidence that almost all future APC retrofits can be completed far more quickly than were historical APC projects derives in part from a comparison of past APC schedules to the project schedule for an entire new coal-fired unit, including its APC systems. Springerville Unit 3, for example, is a 400 MW coal-fired unit that became operational in July 2006, some 33 months after the turnkey engineering-construction contractor was given a notice to proceed with engineering.5Springerville was clearly on an accelerated schedule, as its original planned schedule was about 38 months. The main point here is that typical schedules for large complex power projects can be significantly accelerated. Because the scope of the work involved for an entire new coal unit is at least five times that of a retrofit wet FGD system, EPA believes that even the most complex retrofit APC project can be significantly accelerated as well.

The recently surveyed wet FGD project schedules are not all representative of the shorter project schedules that EPA expects to be prevalent under the MATS Rule. Some of these projects were conducted in a period of regulatory uncertainty without a strong driver for accelerated retrofit completion, tie-in, and subsequent operation – particularly where initiating such operation increases marginal operating costs without a certain regulatory benefit. Factors that will likely accelerate project schedules under the Toxics Rule include the use of overtime and/or two-shift work schedules during construction, and 5- or 6-day work weeks, instead of the 4-day x10-hr schedules often used to minimize cost when time is not of the essence. Increased use of offsite modularization and pre-fabrication of APC components can also shorten schedules and reduce job hours. Also, many of the wet FGD projects performed in response to CAIR or to other legal actions in the same time frame took longer to perform than under normal market conditions due to the initial high demand for a large number of complex wet

FGD systems in a short period of time. Extended lead times in the 2007/2008 time period, as high as 18 months for key wet FGD engineered equipment (such as large recycle pumps, large motors, and chimneys) contributed to extended wet FGD project durations. Increased lead times quickly subsided as the supply chain processed the initial influx of orders for this equipment. Neither the proposed Cross State Rule nor the MATS Rule, however, is projected to require a significant number of large, complex wet FGD systems. The relatively much simpler dry FGD, fabric filter, and other even simpler DSI and ACI systems that may be required under the Mercury and Air Toxics rule will take significantly less time to plan, design, install, and commission than wet FGDs.

5. One-year extension.

Comment 46: The EPA requested comment on a 1-year extension under section 112(i)(3) for "installation of controls." Multiple commenters (18023, 9738, 17297, 17638, 17648, 17696, 17758, 17775, 17810, 17818, 17841, 17843, 17870, 17886, 18025, 18037, 18424, 18426, 18428, 18440, 19114) agree with the extension.

Commenter 18025 states that in the limited cases of extensions beyond 3 years, it will be important for the EPA to ensure that a company uses the additional time to install controls or test the installation of controls and to ensure a unit is only dispatched for reliability purposes so that it does not receive any undue economic gain as a result of an extension.

Multiple commenters (18023, 17297, 17385, 17638, 17696, 17701, 17758, 17775, 17820, 18426, 18434, 18439) ask that the 1-year extension apply in other cases as well. Multiple commenters (18023, 17297, 17758, 17775, 17820, 17886, 19114) also support applying the extension to transmission upgrades. Commenter 19114 asks that the extension should apply if additional gas supply lines must be constructed or replaced, or if required state and federal regulatory approvals to retire the capacity cannot be obtained.

Commenter 17385 asks for clarification of whether energy efficiency and fuel switching measures can count as "controls."

Commenter 18434 stated that this extension should also apply to on-site non-conventional replacement generation through combined heat and power and waste heat recovery. According to the commenter, restricting replacement power to on-site equipment significantly reduces opportunities for facilities to invest in clean replacement power and consider retirement as a compliance strategy. The commenter states that this approach has multiple advantages.

Several commenters (18434, 18439, 19114) ask the EPA to clarify that retirement and any clean replacement power that complies with the NESHAP rule, including off-site combined heat and power and waste heat recovery, can be deemed "controls" under the CAA, thereby allowing the same 1-year extension to apply. Commenter 18439 notes that the EPA should clarify that energy efficiency and fuel switching measures can count as controls for purposes of eligibility for a 1-year extension for compliance if additional time is needed for installation. Commenter 19114 notes that the timeline for constructing a new combined cycle unit is similar to that for retrofitting an FGD system on an existing unit, and could not be completed within a 3-year window.

Several commenters (19536, 19537, 19538) believe that: Shut-down of an existing unit is within the definition of a pollution "control" under section 112, as well as under the CAA generally. The commenters state that section 112 uses "emission control" broadly to refer to pollution reductions of any sort(see, e.g., 42 U.S.C. §7412(d)(3), (d)(5), (d)(6), & h(1) (all using "control" to refer to pollution-reduction and referring to "emission control" achieved by "best controlled similar source")), that in keeping with that general synonymy, section 112 defines "maximum achievable control technology" limit as a limit reflecting the "maximum degree of reduction" achievable(42 U.S.C. §7412(d)(2) & (g)(2)), and the statute confirms that any "measure," "method" or "technique" that reduces hazardous air pollution may be prescribed to accomplish the necessary limitation(42 U.S.C. §7412(d)(2)). The commenters state that elsewhere in the statute, as well, the term "control" is defined broadly enough to include the cessation of polluting operations. *See*, e.g., 42 U.S.C. §7479 (defining "best achievable control technology"). According to the commenters, closure of a high-polluting unit is a measure that reduces pollution, and is therefore a "control" under the CAA. The commenters state that the EPA has, accordingly, recognized in its consent decrees that shut-down is under some circumstances a method of pollution-reduction that is a "control technology" within the meaning of the CAA. *See*, e.g., Consent Decree, *United States v. Tampa Electric Co.*, Civ. No. 99-2524 (M.D. Fla. 204) at 7-8 (prescribing permanent shut-down amongst "emissions reductions and controls" required to comply with CAA). According to the commenter, consequently, the word "control" in section 112 encompasses the shut-down of a polluting unit, and "installation of controls" should be understood to include the on-site physical operations required to accomplish permanent shut-down. Also according to the commenter, the accompanying term "practicable," in section 112(i)(3)(A), allows the EPA to consider the need to provide replacement power necessary to permit such a permanent shut-down. The commenter states that section 112(i)(3) allows the EPA (or state agencies) to provide up to 1 additional year to an existing source where "necessary for the installation of controls," 42 U.S.C. §7412(i)(3)(B), while also establishing that controls are to be installed "as expeditiously as practicable," 42 U.S.C. §7412(i)(3)(A). The commenter states that whether an extension is "necessary" for the installation of controls must be informed by whether those controls can "practicabl[y]" be put in place at an earlier date. According to the commenter, read together, sections 112(i)(3)(A) & (B) allow an extension of up to 1 year to be granted on a case-by-case basis for facilities at which controls cannot practicably be installed within 3 years. The commenter states that the EPA has, elsewhere in its proposed rulemaking, considered reliability to determine the pace at which controls can practicably be installed (*see* 76 FR 25,054, 25,056 & nn. 177-178 (describing EPA's efforts and intention to work with FERC, NERC, the Department of Energy, and regional transmission organizations on issues related to compliance and reliability, particularly in the event unit shutdowns occur in load-constrained areas)).

Commenter 18426 states that the extension, with the factors and conditions for qualifying and applying for the extension, needs to be part of the rule. The commenter provided Michigan's conditions for that state's Hg rules.

Commenter 18034 requests clarification, as the commenter is unaware of any precedent for such an interpretation of the CAA. The commenter states that while the EPA's attempt at flexibility through this interpretation is clear, the commenter is unclear as how other parts of the proposed NESHAP rule should be interpreted and enforced given this new interpretation and poses the following questions: Would such a reconstructed facility be held to the new or reconstructed EGU emission limits in Table 1 or the existing EGU emission limits in Table 2? How does the EPA reconcile this interpretation with the proposed requirement in section 63.9984(a) that a new or reconstructed EGU must comply by the date of the final rule published in the *Federal Register* or upon restart of the EGU, whichever is later? Is this interpretation limited to just EGUs or may states apply this same approach to existing sources subject to other NESHAP rules, for example, a Portland cement kiln subject to the EPA's recently finalized Portland cement NESHAP rule?

Commenter 19122 states that the 1-year extension process seems to apply only to the installation of control equipment and not for installation of systems such as CEMS and BLDS. The commenter recommends that the EPA provide an extension process for procurement of emission monitoring/BLDS as well as for installation of control equipment and streamline the extension process such that a source can be granted an extension if good faith efforts have been made to meet compliance.

Commenter 17868 outlines the EPA prediction that the industry will have very little problem in meeting the 3-year compliance schedule proposed in the regulation if the additional year of compliance time is provided to "some" units. The commenter provides their key assumptions supporting this conclusion as:

1. The use of low-cost, simple, DSI systems to control acid gases, instead of more complex FGD systems;
2. Faster retrofits than similar projects in the past;
3. Compliance requirements of other regulations have no impact on HAP compliance;
4. The small number of projected retirements, about 10 GW of coal capacity;
5. Early planning action by regulated utilities; and
6. Early planning action by RTOs.

Comment 47: Multiple commenters (16850, 17004, 17026, 17887, 18539) comment on retiring or repowering units.

Commenters 17004 and 17026 request that the EPA allow power companies to operate their plants as efficiently as possible, including allowing units that are already scheduled to shut down to operate on a restricted basis without installing additional controls, as they upgrade their facilities and move toward new generation.

Commenters 18434 and 18439 ask the EPA to clarify that retirement and any clean replacement power that complies with the NESHAP rule, including off-site combined heat and power and waste heat recovery, can be deemed "controls" under the CAA.

6. Extensions for retirement and replacement power.

Comment 48: Several commenters (18023, 17638, 17696, 17820, 17821) ask that the provision to allow a 1-year extension apply to all retirements.

Multiple commenters (17841, 18426, 18434, 18441, 18442 18448) ask that a 1-year extension be provided for possible unit retirements, retrofits, or repowering. Several commenters (18434, 18441, 19114) note that this extension should apply to off-site power generation in limited circumstances. Commenters 18031 and 18442 ask that the maximum amount of time allowable be available for these actions.

Commenter 17677 states that for units that elect to shutdown, the EPA should allow significant automatic extensions upon notification of elected unit shutdown. According to the commenter, this will allow the source sufficient time to permit and construct a replacement facility or contract additional power that will most likely have to be constructed.

Commenter 19506 states that the EPA should consider allowing units that a company has scheduled to be shut down to continue to operate beyond the compliance deadline until other units owned by the same company have been fully retrofitted.

Commenter 18450 opposes allowing a fourth year for compliance when building replacement power unless the source can demonstrate an electric reliability issue.

Commenter 18039 objects to granting 1-year extensions for facilities that are building replacement power. According to the commenter, the EPA should avoid allowing a facility in the process of building replacement power, and that would otherwise shut down an existing high-emitting unit at the 3-year compliance deadline, to operate such existing high-emitting unit for an additional year, specifically due to the 1-year extension. The commenter states that in addition, if designing, permitting and constructing replacement power continues beyond a 1-year extension, it should be stressed that the CAA does not allow MACT compliance extension beyond 1-year, whether or not a replacement unit has come on-line.

Commenter 18441 notes that the 1-year extension request, if granted, may create incentives for generation owners faced with compliance decisions to wait as long as possible to submit their deactivation requests to their regional transmission organization in the hope they can get their units extended beyond the January 1, 2015 compliance deadline if their units are deemed by the regional transmission organization in its subsequent deactivation study to be Reliability Critical Units. According to the commenter, in this case, generator owners can effectively attempt to extend the life of their units for an additional year or more with no intention of installing retrofits by simply delaying their deactivation request so they can effectively side-step compliance with the final rule through a potential misuse of the extension process contemplated herein. The commenter requests the EPA provide guidance in the final rule that such an extension for deactivating units only be granted if the unit owners provide the regional transmission organization, with a copy to the EPA, with notice of deactivation by the earlier of 12 months from the effective date of the final rule, or January 1, 2013, a full 2 years in advance of the January 1, 2015 compliance deadline. The commenter notes that nothing in this proposal should be read as limiting the ability of units which are retrofitting but cannot complete such work by the compliance deadline from also being eligible for a compliance extension. The commenter states that nothing in this proposal eliminates a generating owner from petitioning the Secretary of Energy to excise its authority under section 202(c) of the Federal Power Act and section 301(b) of the Department of Energy Organization Act to order the unit remain operational, and nor would this preclude a generator from working with the EPA to establish a compliance schedule.

Response to Comments 46 - 48: The EPA believes that although most units will be able to fully comply within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. That fourth year should be broadly available where it is necessary. Please refer to the preamble where there is a detailed discussion of the fourth year. The EPA is making it clear that permitting authorities have the authority to grant a 1-year compliance extension where appropriate.

The EPA continues to believe that most, if not all, units will be able to comply with the requirements of this rule within 3 years. The EPA also believes that making it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in range of situations described in the preamble, addresses many of the other concerns that commenters have raised.

7. Issues and costs that need to be considered in determining compliance date.

Comment 49: Multiple commenters (16469, 16849, 17403, 17406, 17640, 17722, 17730, 17732, 17734, 17752, 17756, 17757, 17758, 17770, 17774, 17812, 17813, 17815, 17817, 17820, 17821, and 17868, 17876, 17881, 17912, 17925, 17931, 18033, 18037, 18422, 18424, 18428, 18440, 18442, 18447, 18498, 18500, 19114, 19122, 19506) are concerned about the availability of qualified construction and technical labor, as well as availability of equipment.

Multiple commenters (8443, 17383, 17608, 17697, 17722, 17767, 17812, 17868, 17911, 18038, 18419, 18498, 18575) are concerned about the competition between small utilities and larger utilities, for equipment and labor.

Commenter 18433 states that it will be difficult for facilities in remote areas to get vendors and contractors to respond to requests-for-proposals for a single opportunity to sell an ESP when large utilities will also be seeking larger quantities of such equipment from the same vendors.

Commenters 19032 and 19653 believe that too many activities must be coordinated and completed to comply with the proposed rule. The commenter states that these activities include emissions testing to determine what type of capital equipment or upgrades will be required to facilitate compliance, Designing/engineering, permitting, securing financing, construction, start-up and acceptance testing.

Comment 50: Multiple commenters (16849, 17403, 17731, 17752, 17757, 17774, 17775, 17821, 18428) are concerned about major tie-in outages, especially during low peak seasons.

Commenter 18477 does not have shoulder months like the contiguous U.S. Therefore, according to the commenter, there are no specific time periods when outages can occur without impacting electric reliability.

Response to Comments 49 - 50: In both the preamble to the rule and in greater detail in the TSD, the EPA has assessed the feasibility of installing these controls within the compliance window and believes that the controls can be reasonably installed within that time. Although the EPA assessed the ability to install the controls in 3 years (and determined that the controls could be installed in that time-frame), this would require the control technology industry to ramp up quickly. Therefore, the EPA also assessed a time-frame that would allow some installations to take up to 4 years. This time-frame is consistent with the CAA which allows permitting authorities the discretion to grant extensions to the compliance time-line of up to 1 year. This time-frame also allows for staggered installation of controls at facilities that need to install technologies on multiple units. Staggered installation allows companies to address such issues as scheduling outages at different units so that reliable power can be provided during these outage periods or particularly complex retrofits (e.g., when controls for one unit need to be located in an open area needed to construct controls on another unit). In other words, the additional 1-year extension would provide an additional two shoulder periods to schedule outages. It also provides additional opportunity to spread complex outages over multiple outage periods. The EPA believes that while many units will be able to fully comply within 3 years, the 4th year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. The EPA expects that state permitting authorities will make the fourth year available where it is warranted. In addition where necessary to avoid a violation of applicable FERC-approved electric reliability standards the EPA can use existing CAA authorities to allow additional time to come into compliance.

Comment 51: Multiple commenters (8443, 17123, 17297, 17406, 17623, 17716, 17732, 17756, 17716, 17752, 17758, 17820, 17842, 17912, 18024, 18419, 18422, 18440, 18502, 19121) are concerned about financing these projects and the likely cost increases for labor and equipment likely to occur over this compliance period.

Multiple commenters (17254, 17406, 17842, 18422, 18437, 18502, 18539, 18575, 19653) are concerned that these increased costs could affect the affordability of electricity.

Response to Comment 51: The EPA has not observed financing obstacles for pollution control retrofits under its previous programs. The EPA includes publicly-reviewed financial assumptions regarding pollution control investments with its IPM modeling of the power sector. Furthermore, the financial industry views utilities with large customer bases (e.g., AEP, Duke, Edison Intl., Southern Co., TVA) as less risky to finance due to the consistent, ample revenue stream. To reduce financing risk, utilities have the option to award "fixed price" contracts with penalties for exceeding price limits or LD's (liquidated damages) for schedule and/or performance default. Considering the past successes of the pollution control industry regarding retrofits, the EPA believes the financial markets will supply adequate capital for units pursuing retrofit under the final MATS.

Although costs could increase during the compliance period, the EPA anticipates the first wave of retrofit controls orders to be less costly than recent historical prices since suppliers shall compete for work to utilize idle resources. For example, in June 2011 NIPSCO awarded B&W a contract worth $54 million for two wet scrubbers at R.M. Schahfer Generating Station with an operational date of autumn 2013 and 2015 for units #14 (465 MW) and #15 (515 MW), respectively. In another example, Colorado Springs Utility plans to retrofit its 254 MW Martin Drake unit with a FGD for $113 million with projected construction completed by 2014. The EPA expects therefore that the costs it has used in its IPM modeling will be accurate over the life of the compliance period. Documentation for IPM can be found in the docket for this rulemaking or at http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html or at http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

Comment 52: Multiple commenters (18023, 17254, 17640, 17689, 17705, 17716, 17730, 17731, 17761, 17767, 17774, 17808, 17813, 17820, 17821, 17824, 17837, 17841, 17876, 17902, 17931, 18033, 18038, 18419, 18422, 18424, 18428, 18430, 18441, 18442, 18500, 18539, 18575, 19114, 19653) are concerned about grid and electricity reliability.

Commenter 18441 states that the larger regional adequacy impacts can only be determined once the impact of the final rule has been analyzed and units have made their individual retrofit vs. retirement decisions. The commenter believes that the EPA understates the number and size of retirements.

Comment 53: Many commenters (16549, 17055, 17701, 17137, 17697, 17716, 17724, 17725, 17743, 17745, 17757, 17761, 17774, 17775, 17813, 17791, 18038, 18437, 18433, 17887, 17930, 18448, 18540, 19506, 19199) express concern that the EGU MACT will jeopardize the reliability of the U.S. electricity supply by reducing generating capacity through early retirement of EGUs.

Numerous commenters (16549, 17055, 17701, 17137, 17697, 17716, 17724, 17725, 17743, 17745, 17757, 17761, 17774, 17775, 17813, 17791, 18038, 18437, 18433, 17887, 17930, 18448, 18540, 19506, 19199) express concern that the EGU MACT will jeopardize the reliability of the U.S. electricity supply by reducing generating capacity through early retirement of EGUs. Some commenters (18034, 18538, 18907) believe that the EGU MACT may result in rolling blackouts that have economic impacts. Commenter 18034 notes that without reliable, affordable electricity, sensitive populations, such as elderly citizens, may be at risk during severe winter weather or hot summer temperatures.

Some commenters offer comments about processes based on early notification that might be set up to assure that the compliance timeframe did not interfere with electricity reliability. Commentor 17648 suggests that the EPA be notified within 1 year of the effective date of this rule, of compliance plans including plans to retire units. Commenters 18441 and 18448 recommend that plants be required to notify RTOs and ISOs of their plants to retire units so that the RTO/ISO can assess the impact on reliability of the planned closure. In the event that a unit is deemed "reliability critical" the ISO/RTO can plan transmission upgrades and other actions to avoid a loss of grid stability. These commenters envision a "proforma consent decree" to provide additional time if needed.

Comment 54: Commenter 18023 believes the loss of generation capacity caused by early retirement of EGUs would undermine the operational support that is critical to maintaining balance, resilience, and contingency response capability on the bulk power network. The commenter believes the EPA has overlooked the critical role generation capacity plays in providing grid stability.

Comment 55: Numerous commenters (16705, 17055, 17254, 17400, 17403, 17608, 17627, 17761, 17765, 17804, 17813, 17857, 17901, 17911, 17813, 17901, 17904, 17911, 17919, 17930, 18034, 18038, 18437, 18441, 18497, 18500, 18538, 18575, 18023) believe that the EPA has underestimated the number of EGU retirements. Many commenters (16705, 17055, 17403, 17761, 17765, 17627, 17761, 17813, 17901, 17911, 17813, 17901, 17904, 17911, 17919, 17930, 18034, 18038, 18437, 18441, 18497, 18500, 18538, 18575, 18023) cite independent projections that estimate capacity retirements will be much higher than the EPA's estimate. The independent projections cited by commenters include:

- *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, The Brattle Group, December 8, 2010 (estimate 67 GW will be retired as a result of the EGU MACT);
- *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, Edison Electric Institute, prepared by ICF International, January 2011 (estimate 50to 70 GW will be retired as a result of the EGU MACT in conjunction with other new EPA regulations).
- *Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System*, Electric Reliability Council of Texas, May 11, 2011 (predicts that by 2016, the base case scenario will lead to 11 GW of retirements in the state of Texas to all forms of generating capacity, leaving only a -2.3% reserve margin);
- US Department of Energy (Deputy Assistant Secretary, James Wood) (suggested that the approval of new rules for air pollution, water pollution and waste disposal could result in the retirement of up to 70 GW of coal-fueled power generation nationwide. Woods highlighted that these retirements will increase electric rates and lead to pronounced transmission grid reliability issues "…both because of the shutdowns and because of the intermittency of renewables.").
- Ira Shavel & Barclay Gibbs, Charles River Associates, "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT" (Dec. 16, 2010)(estimate 39 GW will be lost through early retirement).
- *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, North American Electric Reliability Corporation, October 2010 (Estimate that 78 GW from coal, oil, and gas EGUs will be lost through early retirement over the next 10 years).
- *U.S.Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?*, Bernstein Research, October 2010. (estimate that close to 60 GW of coal fueled capacity will find it "uneconomic" to install MACT and will shut down. Also predicts that capacity margins would decrease by 7 to 15 % and reliability is forecasted to go down).
- *NERA Economic Consulting, May 2011 (estimates* 48 GW of additional coal-fired generating capacity will retire prematurely by 2016).
- PIRA (states that over 160 GW of coal units do not currently have scrubbers installed. Of these, about 55 GW have announced plans for scrubber retrofits, leaving a potentially large universe (over 105 GW) of "vulnerable coal units.").

- Credit Suisse, April 26, 2011 (predicts that at a 60 GW retirement capacity and suggests an additional 24 GW would be needed to maintain reserve margins at 15 %).

Some utilities provide projections of the capacity they anticipate retiring as a result of this rule. These include:

- Commenter 17627 estimates that 5.4 GW of coal-based generation capacity will be lost as a result of the EPA's regulations;
- Commenter 17757 estimates that 5 coal-fired plants (6,000 MW) will be shut down as a result of the EGU MACT.
- Commenter 17821 plans to retire 6 units, or 1,125MWs of coal fired capacity at the W.C. Beckjord Station by January 1, 2015, principally due to the EGU MACT rule.
- Commenter 17821 plans to retire the 163 MW Miami Fort Unit 6 on January 1, 2015.
- Commenter 17821 estimates that approximately 1,574 MWs of additional coal-fired capacity is at risk of shutdown due to new or pending EPA regulations, including the EGU MACT rule.

Comment 56: Commenters 17919 and 18033 refer to statements made by FERC that acknowledge FERC's preliminary assessment on the impact of EPA rules on coal-fired generating capacity "showed 40 GW of coal-fired generating capacity 'likely' to retire, with another 41 GW 'very likely' to retire." (see letter dated August 1, 2011 from the FERC Chairman John Wellinghoff). Commenter 17919 also quotes from another letter from FERC Commissioner Marc Spitzer in which he argues that regulated entities should not have to make such a "Hobson's" choice between EPA regulations on reliability and entities' requirements to uphold FERC-approved reliability standards. Commenter 18033 claims that the EPA has failed to document its discussions with FERC on the impacts of the EGU MACT on electric system reliability. This commenter believes it is inappropriate for the EPA not to include a record of those discussions in the rulemaking docket and that by not doing so the EPA has not adhered to the statutory requirements of the CAA, which requires the EPA to provide the public with an opportunity to review and comment on these documents.

Commenter 18033 states that the EPA also attempts to fall-back on early collaboration with key stakeholders to prevent the potential for skyrocketing electricity prices and job losses. According to the commenter, the agency states that, "[i]n addition, EPA itself has already begun reaching out to key stakeholders including not only sources with direct compliance obligations, but also groups with responsibility to assure an affordable and reliable supply of electricity including state Public Utility Commissions (PUC), Regional Transmission Organizations (RTOs), the National Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and DOE." The EPA further states, "[i]t is EPA's understanding that FERC and DOE will work with entities to ensure an affordable, reliable supply of electricity…" The commenter states that it can find no evidence of these consultations in the rulemaking docket and that the public has no ability to discern whether EPA is presenting the implications of this rule with its overly optimistic DSI assumption thereby coloring the perceptions of the stakeholder. The commenter states that as of October 2010, NERC as one of the identified stakeholders did not share the EPA's view of de minimus impacts to electric power generating sector. According to the commenter, overlapping compliance schedules for the air and solid waste regulations, along with the required compliance for rule 316(b) following shortly thereafter, may trigger a large influx of environmental construction projects at the same time as new replacement generating capacity is needed. The commenter states that such a large construction increase could cause potential bottlenecks and delays in engineering, permitting and construction. The commenter asserts that based on this assessment, either NERC has changed its position since this time to align with the EPA based on information not included in the rulemaking docket, or the EPA is not being forthcoming about the reality of these "collaborations" to deal with this important issue. The commenter states that in any event, and unsurprisingly, the foregoing demonstrates that FERC – responsible for delivering reliable electricity to the country – is not as confident in the EPA's assessment of the situation as the EPA portrays it to be.

Following FERC's responses to Senator Murkowski, the commenter joins the Senator's extreme concern with the impending situation, as described in her August 3 press release, "[h]aving received FERC's responses this week, I must say that I am now less confident [after initially hearing the Chairman's plans for an interagency task force] of that being the case." The commenter states that preliminary review of FERC's responses completely validates her position.

The commenter states that in response to the EPA's exaggerated representations in the preamble, Chairman Wellinghoff stated in his letter, "…this information assessment offered only *a preliminary look* at how coal-fired generating units could be impacted by EPA rules, and is *inadequate* to use as a basis for decision-making, given that it used information and assumptions that have changed" (emphasis added). The commenter states that this sentiment is further confirmed in Commissioner Moeller's response, "[a]ccording to OER staff, EPA's reliability analysis has been *limited*," and that staff have, "pointed out to EPA that a reliability analysis should explore transmission flows on the grid, reactive power deficiencies related to closures, loss of frequency response, black start capability, local area constraints, and transmission delivery" (emphasis added). According to the commenter, in sum, the EPA's "trust us" mentality has far underestimated the complexity underlying the delivery of affordable and reliable electricity.

The commenter states that this is further evidenced by the fact that neither FERC nor the EPA has conducted a cumulative impacts analysis and that FERC's assessment that 81 GW of "likely or very likely" retirements may result from the implementation of this suite of rules, further highlights the need -- as expressed by the commenter – for a more transparent and open process to deal with these important issues. The commenter states that recognizing the Chairman's reservations about the results of this preliminary study, it nevertheless highlights the EPA's failure to disclose this critical study and any other material that may exist regarding the EPA-FERC consultation process.

The commenter joins Commissioner Moeller's recommendations to have FERC: (1) use its expertise to perform an analysis of the EPA's rules that could impact reliability of electricity – and *disclose that analysis for public comment* – and then hold a technical conference for public input; and (2) have the EPA extend the timing of these regulations as the agency's schedule "does not conform to the relevant planning horizons in the electric sector of our economy, one of the most capital-intensive sectors of industry."

The commenter states that understatement of potential coal-fired EGU retirements and electricity prices will be especially acute if the EPA holds the line with its new source emissions limits. The commenter states its belief that the new source emissions standards are based on the impermissible HAP-by-HAP approach, which makes it difficult to foresee investment in new coal. According to the commenter, Credit Suisse projects that at a 60 GW retirement figure, there would need to be an additional 24 GW just to maintain reserve margins at 15% begging the important question of where will coal-dependent regions of the county replace these important sources of energy. The commenter states that despite the EPA's effort to "level the playing field," the agency has done an inadequate job of informing the public as to the consequences of such a policy and that the public will only be able to confirm if the EPA includes all of the relevant documents regarding this particular issue. The commenter asserts that the public is entitled to an opportunity to inspect these documents and provide comment.

The commenter states that the failure to provide evidence of the communication between FERC and other key stakeholders regarding the electric reliability issue is inexcusable and that the EPA cannot claim it has adhered to the statutory requirements of the CAA without installing all records related to these consultations and permitting the public an opportunity to meaningfully comment. The commenter asserts that given FERC's reservations about the EPA's portrayal of the situation, there is a glaring need for more serious collaboration on this issue with an opportunity for public participation and that the EPA must not sacrifice electric affordability and reliability at the feet of an arbitrary regulatory calendar.

According to the commenter, these are errors that are directly at odds with the rulemaking requirements under section 307(d). The commenter states that under paragraph (d)(3), a "notice of proposed rulemaking…shall be accompanied by a statement of its basis and purpose," and this statement "shall include a summary" of the "factual data on which the proposed rule is based;" and the "methodology used in obtaining the data and in analyzing the data," and that paragraph (d)(3) instructs that "[a]ll data, information, and documents referred to in this paragraph shall be included in the docket on the date of publication of the proposed rule." According to the commenter, the EPA has not followed these statutory commands as the requirement to provide "all data" on which the proposal was based was not included in the preamble nor in the docket at the time the proposal was published in the Federal Register.

The commenter states that the D.C. Circuit Court of Appeals has held that the public notice and comment requirements "are designed (1) to ensure that Agency regulations are tested via exposure to diverse public comments, (2) to ensure fairness to affected parties, (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review." According to the commenter, these objectives have been undermined in this rulemaking process, and there are indications in the preamble that regardless of the public input, the EPA has a predetermined outcome in mind when it crafted these proposed regulations. The commenter notes that the proposed rule states, "…EPA expects that sources will begin promptly, *based upon this proposed rule*, to evaluate, select, and plan to implement, source-specific compliance options" and that the Court's holding highlights the issue of whether EPA's unreasonable timeframe will effectively prevent the agency from being responsive to public comments.

Comment 57: Commenter 19114 believes that the EPA has not taken into consideration the impact of upsets or variations in operation, process or fuel specification could have on reliability. Such conditions, the commenter argues, could result in a unit having to be derated or taken off line to remedy the situation. The commenter recommends that the EPA more thoroughly examine the impact of process upsets on reliability of the electric supply.

Comment 58: Several commenters (17813, 17911, 17930) are concerned that the EPA has underestimated the impact of rising demand on electric system reliability. Commenter 17813 argues that even without the EGU MACT retirements, the Texas ERCOT grid will struggle to meet rising electricity demand. They note that Texas is growing at a rate of 1,000 people a day, and that ERCOT anticipates capacity shortfalls of at least 7,000 MW in 2015, 18,245 MW in 2020, and 50,000 MW in 2030 to maintain a reserve margin of 13.75%. Commenters 17911 and 17930 note that the current electric power market has significant excess capacity that is the result of power consumption cutbacks caused by a stalled economy. If industry were to return to pre-2008 levels, they argue the market availability and market demand would be more closely aligned, and even the EPA's estimated 9 GW retirement may have an impact.

Comment 59: Several commenters (17627, 18037, 18441) note that the EGU MACT has already had an impact on coal-fired electricity generation. They note that 6,900 MW (11% of PJM coal capacity) did not clear the recent PJM capacity market auction completed in May 2011. These commenters believe that the coal plant offers, which included anticipated environmental compliance costs, likely did not clear the market because they were high relative to demand response offers. They further assert that capacity that does not clear in the PJM capacity market auction is likely to be retired and that they expect a much higher percentage of coal capacity will not clear the 2015/16 capacity auction.

Comment 60: Multiple commenters (8443, 16705, 17400, 17761 17697, 17724, 17804, 17813, 17911, 17919, 17930, 18034, 18037, 18448, 18538, 19114) believe the EPA's analysis underestimates the potential impacts on electric system reliability because the agency has failed to fully account for the potential effects of other related, ongoing and or upcoming regulatory initiatives affecting the electric generation sector, including more stringent NAAQS, upcoming emission guidelines for GHG emissions (under NSPS as well as related PSD guidance), coal combustion residue (CCR) regulations, and regulations under section 316(b) of the Clean Water Act (CWA) for cooling water intake structures. Commenter 8843 worries that the "enormous" investments required to comply will lead to reliability issues by closing down anywhere from 30-50% of coal-fired power plants. Commenter 17055 worries that the EPA has not considered the impact of the RICE regulations that could potential result in the loss of the small generators upon which many municipalities rely. They note that elimination of those units could create local supply challenges.

Comment 61: Commenter 17725 argues that more time is need to comply with the rule because the utilities that participate in the PJM and ISO-NE auctions have already made commitments to supply power through May 31, 2015. They further note that the last date to submit a delist bid for ISO-NE for PY 2015/2016 will have passed before the final EGU MACT is published.

Comment 62: Several commenters (17774, 17919, 18441) disagree with the EPA's statements that reliability challenges related to early EGU retirements can be managed. Commenter 18441 believes the RTO/ISO notification procedures are not adequate to meet the magnitude of changes and potential retirements that could result from implementation of the proposed rule. Commenter 17774 states that South Carolina does not have an RTO or ISO to assist in planning. This commenter believes that the EGU MACT will cause long-range planning challenges and reliability concerns in the South Carolina, because of the lack of RTOs and the significant shutdowns of coal plants in the southeastern U.S. Commenter 17919 believes that the industry cannot rely on EPA emergency authorities because the EPA and the U.S. DOE cannot agree on whether or not emergency orders actually forestall agency enforcement actions. Commenter 19114 is concerned that the EPA has not yet consulted with DOE and FERC and worries that the necessary rule coordination or harmonization is not occurring.

Response to Comments 52 - 62: The EPA has considered the concerns raised by commenters and has concluded that given the flexibilities provided in the final rule, the requirements of the final rule for existing sources can be met by most sources without adversely impacting electric reliability. In particular, the EPA believes that the flexibility of permitting authorities to allow a fourth year for compliance should be available in a broad range of situations (as discussed below), and that this flexibility addresses many of the concerns that have been raised. Furthermore as indicated below, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability.

The EPA considered the impact that potential retirements in response to this rule will have on resource adequacy. In considering these impacts, the EPA considered both the analysis it has conducted as well as analyses conducted by a number of other groups. The EPA's analysis shows that the expected retirements of coal-fueled units as a result of this final rule (4.7 GW) are fewer than was estimated at proposal and much fewer than some have predicted. Because concerns have been raised that the use of DSI may not be as prevalent as the agency has predicted and because this could lead to more coal retirements, the agency also performed a sensitivity analysis in which less DSI systems and more scrubber systems were installed. In that sensitivity, we see approximately 1 more GW of retirement. This small change would have only a very small potential impact on reliability. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: expected demand for electricity, the cost of alternative generation, and the cost of continuing to generate using an existing unit. e EPA's assessment looked at the capacity reserve margins in each of 32 sub-regions in the continental U.S. Demand forecasts used were based on EIA projected demand growth. The analysis shows that with the addition of very little new capacity, average reserve margins are significantly higher than required. The NERC assumes a default reserve margin of 15 percent while the average capacity margin seen after implementation of the policy is nearly 25 percent. Although such an analysis does not address the potential for more localized reliability concerns associated with transmission constraints or the provision of location-specific ancillary services (such as voltage support and black start service), the number of retirements projected suggests that the magnitude of any local reliability concerns should be manageable with existing tools and processes.

Several outside analyses have reached conclusions consistent with EPA's analysis. The DOE, in December 2011, published a report that looked at resource adequacy in the bulk power system when faced with a stress test which was a regulatory scenario far more stringent than EPA's regulations.[10] For this stress test, in addition to CSAPR and MATS requirements, each uncontrolled electric generator is required to install both a wet FGD system and a fabric filter to reduce air toxics emissions. If such installations are not economically justified, this scenario assumes that the plant must retire by 2015. In reality, as discussed previously, power plant owners will have multiple other technology options to comply with the regulations – options that typically cost less than installations of FGDs and fabric filters. The analysis finds that target reserve margins can be met in all regions, even under these stringent assumptions. Moreover, in every region but one (TRE), no additional new capacity is needed. In TRE, the analysis finds that less than 1 GW of new natural gas capacity would be needed by 2015 beyond the additions already projected to occur in the Reference Case. This analysis also finds that the total amount of new capacity that would be added by 2015 is less than the amount that is already under development.

In August 2011, PJM Interconnection – the Regional Transmission Operator (RTO) responsible for planning and reliable operation of the bulk power system serving all or portions of 13 states in the Mid-Atlantic and Midwestern regions - issued a report analyzing the impacts of the CSAPR and the proposed MATS rule.[11] Although PJM's analysis assumes substantially more retirements than EPA projects, it nevertheless concludes that resource adequacy is not threatened in the PJM region. This is particularly significant, given that the PJM region is one of the largest and most heavily dependent on coal-fueled

[10] U.S. Department of Energy, December 2011, "Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations".
[11] PJM Interconnection, August 26, 2011, "Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants."

generation in the country. The PJM analysis notes, as EPA has acknowledged, that even where there is adequate generation capacity on a regional basis, localized reliability issues may emerge in connection with retirements that may need to be addressed.

In June 2011, the Bipartisan Policy Center issued a report analyzing potential collective impacts of EPA's pending power sector rules and concluding that "scenarios in which electric system reliability is broadly affected are unlikely to occur."[12]

The EPA has reviewed industry and NERC studies suggesting, contrary to the EPA's and these other groups' analyses, that EPA rules affecting the power sector (including this final rule, the CSAPR, EPA's proposed rule addressing power plant cooling water intake systems under section 316(b) of the Clean Water Act (CWA), and EPA's proposed rule addressing coal combustion residuals under the Resource Conservation and Recovery Act) will result in substantial power plant retirements. Some of these studies predict that such levels of retirements will have adverse effects on electric reliability in some regions of the country. Although the specifics of these analyses differ, in general they share a number of serious flaws in common that call their conclusions into question.

First, most of these studies make assumptions about the requirements of the EPA rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals or final rules. For example, a large proportion of the retirements projected by several of these studies is attributable to their inaccurate assumption that EPA's cooling water intake rule under CWA section 316(b) would require all or virtually all existing power plants to install cooling towers. In one study, the reliability effects reported are based on inaccurate assumptions that all existing EGUs with a capacity utilization factor of less than 35 percent would close, and that all in-scope electric generators would be required to install cooling towers within 5 years, whereas the not-selected options with closed cycle cooling in EPA's proposal envisioned that permit authorities could exercise discretion to allow facilities 10 to 15 years' time to comply. In most cases, these analyses were performed before the CWA section 316(b) rule or the MATS rule were even proposed; even analyses subsequent to the CWA section 316(b) proposal continue to inaccurately portray EPA's proposed approach.

Second, in reporting the number of retirements, many analyses fail to differentiate between plant retirements attributable to the EPA rules and older, smaller, and less efficient plants that are already scheduled for retirement because owners have made business decisions, based in significant part on market conditions, not to continue operating them.

Third, most of these analyses fail to account for the broad range of responses available to address electric reliability concerns associated with power plant retirements, including upgrades to the transmission system, construction of new generation, and implementation of demand-side measures. These measures are discussed at greater length below.

As a preliminary matter, none of these situations, either alone or in combination, will necessarily lead to an electric reliability problem. There is excess generating capacity in the U.S. today and in most cases an EGU that closes, either temporarily until it comes into compliance or permanently, will not cause a reliability problem. As explained above, our modeling of the impact of this final rule at the regional level projects retirements of less than one percent of nationwide generating capacity and confirms that there will continue to be adequate capacity in all 32 subregions of the country as sources comply with

[12] Bipartisan Policy Center, June 2011, "Environmental Regulation and Electric System Reliability".

the rule.[13] This analysis shows that significantly less capacity will close in response to the final rule than might have under the proposal. Moreover, the regional modeling of retirements demonstrates that plants that close in response to this rule are spread out across the country rather than clustered in one area. Outside analyses have identified many of the same flaws in studies projecting large-scale retirements as a result of EPA's power sector rules. For example, On August 8, 2011, the Congressional Research Service (CRS).[14] issued a report that report that concluded that studies that assert that EPA rules will cause reliability problems, often make assumptions about the requirements of the rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals. CRS further noted that EPA's rues will primarily affect units that are more than 40 years old, that have not yet installed state-of-the-art pollution controls, and that are inefficient. Many of these plants are being replaced by combined cycle natural gas plants, driven more my lower gas prices than by EPA's regulations. The June 2011 Bipartisan Policy Center report referenced above likewise highlighted many of these same shortcomings in the studies in question[15]as did M.J. Bradley and Analysis Group in a June 2011 report.[16]

Comment 63: Numerous commenters (17402, 17403, 17689, 17697, 17705, 17730, 17734, 17736, 17757, 17758, 17761, 17770, 17800, 17808, 17813, 17815, 17817, 17820, 17821, 17868, 17877, 17881, 17925, 17931, 18016, 18021, 18024, 18033, 18424, 18430, 18433, 18442, 18447, 18498, 1850, 18502, 19032, 19114, 19121) note that there are likely to be delays due to permitting, which will likely increase due to the volume of utilities complying with this rule.

Multiple commenters (17689, 17821, 17868, 17877, 17881, 18024, 18442) specifically reference the NSR process.

Multiple commenters (17730, 17736, 17758, 17808, 17820, 17821, 18024, 18037, 18428, 18447, 19114) specifically reference the PSD process.

Multiple commenters (17402, 17757, 17736, 17800, 17820, 17821, 18428, and 18502) are concerned with the extra delay that FGD landfill permitting and building could cause.

Commenters 17821 and 18428 are specifically concerned with GHG permitting and an associated BACT determination.

Commenter 18424 is concerned that utilities must have rate-payer financed capital investments approved by state regulatory bodies, which can expand the compliance time by many months.

Commenter 17813 is concerned about pre-permit approval evidentiary hearings required in Texas, which typically exceed 2 years in duration.

Commenter 18031 notes that Minnesota utilities must comply with the Minnesota Mercury Emission Reduction Act of 2006 ("MERA"), which requires review by the Minnesota Pollution Control Agency.

---

[13] *See* Technical Support Document on Resource Adequacy in this Docket.
[14] James E. McCarthy and Claudia Copeland, Congressional Research Service, August 8, 2011, "EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?".
[15] Bipartisan Policy Center, June 2011, "Environmental Regulation and Electric System Reliability".
[16] M.J. Bradley & Associates and Analysis Group, June 2011, "Ensuring a Clean, Modern, Electric Generating Fleet while Maintaining Electric System Reliability."

Commenter 18433 cites Guam's procurement laws and lengthy procurement process that may take longer than the EPA's deadline would allow.

Commenter 19114 states that prior to beginning construction, some state regulations require obtaining public utility commission approval in the form of a certificate of need.

Commenter 18450 asks that the EPA establish an expedited permitting process for those affected units that require permit amendments to install HAP controls.

Response to Comment 63:

Permitting Process under the Clean Air Act can cause Delays

Some commenters thought that EPA permitting could cause delays in implementing this rule. The EPA recognizes that, following the vacatur of the new source review (NSR) pollution control project exemption in *New York v. EPA, 413 F.3d 3, 40–41 (D.C. Cir. 2005),* pollution control projects, including pollution control projects constructed to comply with this rule, have the potential to trigger NSR permitting. Based on an analysis done in 2005 that looked at SCR and FGD for CAIR compliance, but that remains current and relevant for all pollutants except for GHG, EPA believes that NSR requirements would not significantly impact the construction of pollution controls that are installed to comply with this Rule. In addition it is very unlikely that pollution control projects would cause GHG increases that would exceed the 75,000 tons per year threshold either as a result of either chemically manufacturing GHGs or as a result of parasitic load. The EPA concludes therefore that there will be no significant impacts on timing from NSR for any pollution control projects resulting from this rule. Should NSR be triggered it would at most be for just a few of the projected control installations.. In the limited circumstances where pollution control installations under the Mercury and Air Toxics Standards may trigger NSR, we also note that an expedited permitting process can occur with sufficient time to obtain permits and achieve emission reductions. For this reason, we strongly encourage permitting

State Requirements Can Cause Delays

Some commenters said that states may have laws and other requirements that will cause companies to delay implementation of this rule. Some companies may construct replacement generation as a compliance strategy. State pre-construction permitting requirements depend upon each individual state. Some states do not require pre-construction permits while some others require public utility commission (PUC) approval. For states obtaining PUC pre-approval for cost recovery, authorization typically averages seven months and is obtained usually within one year.[17] Furthermore, while PUC approval is necessary to recover investment costs through rate payers, it is not a prerequisite for obtaining credit or performing conceptual studies. EPA encourages all parties, state regulators, transmission operators, and companies, to work together in a coordinated and reasonable effort to implement this regulation within the compliance time frame. The EPA continues to believe, based on the analysis discussed at the beginning of this section, that most, if not all, units will be able to comply with the requirements of this rule within 3 years. The EPA also believes that making it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in the range of situations described elsewhere in this document, addresses many of the other concerns that commenters have raised.

[17] "Public Utility Commission Report" March 31, 2011 by M.J. Bradley & Assoc LLC; web site: http://www.epa.gov/ttn/atw/utility/puc_study_march2011.pdf

Time frame for Compliance Is Too Short to Construct and Permit an FGD Landfill

As we have said elsewhere in this document, the compliance deadline allows sufficient time for completing landfills for FGD solids disposal. For example, DP&L will construct a landfill within 18 months to accept wastes generated from Stuart and Killen stations scrubbers. The EPA notes, however, that retrofitting units do not necessarily need to complete landfill construction ahead of commencing operation of the retrofit to achieve cost-effective emission reductions under the Transport Rule programs. Such a source may either utilize a completed portion of the newly permitted landfill under construction, transfer waste off-site to a permitted landfill within the owner's fleet, or contract waste removal (and disposal) services. For example, Dallman station subcontracts coal ash disposal at a local abandoned mine. The EPA uses a disposal cost assumption of $30-$50 per ton for wet FGD, dry FGD, and DSI controls, which the EPA developed in consultation with an experienced power sector engineering firm.

EPA should Establish an Expedited Permitting Process

As explained above and in the Preamble to the rule, the EPA does not feel that a new expedited process is necessary. If all parties work diligently and proactively, state permitting will not prevent facilities from coming into compliance with this rule within the compliance period. If, however there is an unexpected delay that could not be prevented by the facility's owner, the EPA expects the 1-year extension of the compliance time to be available.

Comment 64: Multiple commenters (16705, 17055, 17701, 17725, 17400, 17608, 17724, 17775, 17791, 17812, 17815, 17834, 17868, 17868, 17868, 17887, 18441, 18497, 18500, 18023) argue that the EPA is unrealistic about the ability of utilities and state or regional energy authorities to avoid electricity reliability issues after the rule is implemented. These commenters believe the rule may result in the shutdown of certain units that are critical to the reliability of electric supply on a timeline that is faster than the time necessary to replace the power or upgrade transmission. Commenter 17608 notes that the EPA's assumption that industry can comply quickly with the rule was a key assertion in the EPA's conclusion that reliability will be unaffected.

These commenters identified several logistical problems that they believe may take longer to overcome than the 3- to 4-year time period allowed by the rule. These include:

- Time for coordination of offline time for the installation of pollution controls on several plants in the same region.
- Time to obtain access to natural gas pipelines for repowering or replacing a plant with a natural gas generator.
- Time for planning, building, and interconnecting transmission lines to replace retired EGU capacity.
- Time to construct new EGUs or other alternative energy sources.

These commenters argue that the time needed to design, procure and permit new control equipment takes several years and that even if these steps could be accomplished in 2 years, there would realistically remain only 6 months in the third year when control equipment installation can occur (i.e., during the spring and fall periods of reduced electricity demand). Commenter 17775 notes that electricity demand is high the other 6 months of the years and that consequently most units must either be online or on standby to meet demand peaks. The commenter argues that failure to have an adequate number of EGUs available during this period could result in power curtailments or, in the worst case, brownouts or rolling blackouts. Commenter 17775 estimates that installation of new control equipment required by the EGU MACT would take at least 6 years to complete.

Response to Comment 64: The EPA's authority for setting the compliance time frames is set out in the CAA. In developing this proposed rule, the EPA has performed specific analysis to assess the feasibility (e.g., ability of companies to install the required controls within the compliance time-frame) and potential impact of the proposed rule on reliability. For that analysis entitled "An Assessment of the Feasibility of Retrofits for the Toxics Rule" dated March 9, 2011, the EPA has projected the quantity of each APC technology that may need to be newly retrofitted and in service by the compliance date(s). The EPA used its IPM model to analyze which APC technologies would likely be used, and in what quantities, to achieve compliance with the proposed Toxics Rule.

The EPA's assessment shows that a reasonable, moderately paced effort of the power sector and supporting industry, including some early starts, would result in many of the needed retrofits being installed by January 2015 with some needing up to an additional year. In order for all retrofits to be completed by January 2015, most projects would have to start early and the sector would have to engage in a more aggressive deployment program. In the event that individual projects cannot be completed by the January 2015 statutory deadline for compliance, the CAA offers affected sources the opportunity to apply for a 1-year extension.

Although the EPA assessed the ability to install the controls in 3 years (and determined that the controls could be installed in that time-frame), this would require the control technology industry to ramp up relatively quickly. The EPA also assessed a time-frame that would allow some installations to take up to 4 years. This time-frame is consistent with the CAA which allows permitting authorities the discretion to grant extensions to the compliance time-line of up to 1 year. This time-frame also allows extra time for staggered installation of controls at facilities that need to install technologies on multiple units. Staggered installation allows companies to address such issues as scheduling outages at different units so that reliable power can be provided during these outage periods or particularly complex retrofits (e.g., when controls for one unit need to be located in an open area needed to construct controls on another unit). In other words, the additional 1-year extension would provide an additional two shoulder periods to schedule outages. It also provides additional opportunity to spread complex outages over multiple outage periods. The EPA believes that while many units will be able to fully comply within 3 years, the 4th year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. The EPA expects that state permitting authorities will make the fourth year available.

Comment 65: Commenter 17697 writes that the proposed rule is unrealistic about the ability of the Guam Power Authority (GPA) to avoid electricity reliability issues in 2014 when compliance with this rule begins. The commenter states that there will be a substantial impact on Guam's electric rates

Response to Comment 65: The EPA agrees that the unique considerations faced by non-continental EGUs warrant a separate subcategory for units that use liquid oil-fired units in non-continental areas such as those on Guam and has included such a subcategory in the final rule. At proposal, the EPA did not have all of the data from liquid oil-fired units in non-continental areas (e.g., Guam, Puerto Rico) and solicited comment on whether a subcategory should be established, based on the data to be received, for non-continental oil-fired EGUs. The EPA has now received these late data and, based on those data, we determined the emissions characteristics of the non-continental units were different, and, therefore, the Agency is finalizing a non-continental subcategory for liquid oil-fired EGUs in Guam, Hawaii, Puerto Rico, and the U.S. Virgin Islands. The EPA is not aware of any liquid oil-fired EGUs in any of the other

U.S. territories that meet the CAA section 112(a)(8) definition but, if there are such units, they would also be part of the non-continental subcategory.

The EPA agrees that the unique considerations faced by non-continental refineries, including a limited ability to obtain alternative fuels that lead to different emissions characteristics, warrant a separate subcategory for these EGUs. The EPA believes that units in this subcategory will comply through the use of cleaner oils or, for PM, through the installation of an ESP.

Comment 66: Commenters 17724 and 17805 ask that the EPA take into consideration the advance determination of prudence (ADP) process, which is a process to obtain concurrence from regulatory commissions that its decisions on options (and required expenditures) for future energy resources and modifications to existing energy resources are prudent. The commenters state that the ADP process, in states where it is available, takes almost 12 months to complete and is a critical step for investor-owned utilities seeking financing for modifications or new construction.

Commenter 17821 also mentioned prudency review by regulatory authorities.

Response to Comment 66:

Fiduciary Obligations Prevent Expenditures until Rule Finalized

Multiple comments claim initiating major capital expenses prior to the rule's promulgation violates a public company's fiduciary obligations. In all cases, the comments fail to quantify financial burdens to justify their position. A corporation's obligations go beyond fiduciary trust: they include civic responsibilities for public (and employee) health, as well as accountability for future direction (as determined by the board of directors). In response to these monetary assertions, the EPA recognizes the adversity towards financial risks associated with installing controls equipment prior to rule promulgation; however, the expenditures for determining compliance requirements (pre-award work) are minimal. The EPA funded a study to update and improve retrofit control costs modeled within IPM for the Cross-State Rule. From these studies, engineering and construction management costs (as a percentage of total installed cost) range from 4.1% to 7.3% (basis: 500 MW unit). Considering industry typically limits conceptual engineering not to exceed 10% of total engineered cost, by extension, pre-award work accounts for less than 1% of total installed price. [Conceptual engineering studies are defined as: establishing project scope, type of controls, control's performance, auxiliary equipment, and permit plus funding requirements.] Since conceptual engineering is necessary to assess potential unit modification options, the EPA believes these pre-award minor expenditures do not violate fiduciary obligations; rather, they provide valuable planning information for future regulatory compliance. For example, Nebraska Public Power District (NPPD) commissioned a $2.4 million study to develop a "ready to issue" contract for an FGD retrofit estimated to cost $1 billion for the 1,365 MW Gerald Gentleman Station.[18] This represents 0.24% of installed cost. Since conceptual engineering is necessary to assess potential unit modification options, the EPA believes that these pre-award minor expenditures do not violate fiduciary obligations; rather, they provide valuable information for future planning for regulatory compliance, which appears to serve a sensible fiduciary purpose.

Negotiating Contracts, Competitive Bid Evaluation – More Time Required for Compliance

[18] "S&L to Develop Cost Estimates, Plans for FGD at Gerald Gentleman"; Utility E-Alert #1030, June 24, 2011; McIlvaine Company

Contract negotiation through the competitive bid process is an agreement achieved between a buyer (utility) and seller (supplier). Ultimately, the buyer determines length of time spent in negotiation, and concludes negotiations by signing an award for goods and/or services.

<u>Owner's Decisions & Options</u>

Citing procedural difficulties (interfacing with multiple entities, meeting once a year, etc.) do not constitute sufficient basis for inability to meet compliance dates. The owner is ultimately responsible for assuring adequate and timely compliance by exercising imitative over a "business as usual" approach. Moreover, MATS is inherently flexible – it allows an owner multiple options to attain compliance deadlines; namely, purchase power, shift power generation to cleaner units (combined cycle plants, stations with emission controls, etc.), expedite retrofit work (utilize multi-shift schedule or extended overtime), fuel switching/blending, upgrade existing equipment, replace equipment/components, and retrofit existing equipment – or any combination there-of.

Comment 67: Multiple commenters (18023, 17608, 17638, 17716, 17752, 17756, 17820, 17821, 17840, 17868, 17904, 17925, 17931, 18033, 18502) have concerns with "early planning" and "forward planning" recommended by the EPA. Commenter 18023 notes, "If EPA intended this to be a direct final rulemaking, it should have said so."

Commenter 17911 states that municipalities may not make any significant financial or operational changes before the rule is promulgated, otherwise, they may be violating their fiduciary responsibilities.

Commenters 18428 and 19114 state that it would be imprudent planning for utilities to commit capital without knowing what the final standards are, as the risk of penalties and uneconomic investments is too great. The commenters state that more fundamentally, utilities contemplating retrofits to generating units in rate-regulated states such as those in which the commenter operates run a substantial risk of non-recovery if they make capital commitments before a final rule is issued.

Comment 68: Commenter 18421 recommends that the EPA, the DOE, and the FERC work closely with regional utility planning and operation centers, the National Association of Regulatory Utility Commissions, state PUCs, and utilities to ensure that the measures available preserve the reliability of the electric system.

Commenter 17741 is concerned that the compliance time will not allow adequate prep time, causing utilities to shutter multiple units or entire plants. The commenter is concerned about job loss.

Response to Comments 67 and 68: In the preamble to the proposed rule, the EPA urged power generators and others to perform advanced planning so as to be prepared to implement the regulation in the 3-year compliance timeframe. A number of commenters took exception to that. Many stated that they can't begin planning until they know what the rule is for certain. Others said that they were in fact doing that planning so that they would be able to comply within the compliance timeframe.

In the MATS preamble, the EPA stated that, although there are a significant number of controls that need to be installed, with proper planning, we believe that the compliance schedule established by the CAA can be met. The EPA pointed out that there are already tools in place (such as integrated resource planning, and in some cases, advanced auctions for capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as the rule. In addition, the EPA itself is reaching out to key stakeholders including not only sources with direct compliance obligations, but also groups with responsibility to assure an affordable and reliable supply of electricity including state Public Utility Commissions (PUC), Regional Transmission Organizations (RTOs), the National Electric Reliability Council (NERC), the FERC, and DOE. The EPA intends to continue these efforts during the implementation of this rule. It is the EPA understands that FERC and DOE will work with entities whose responsibility is to ensure an affordable, reliable supply of electricity, including state PUCs, RTOs, the NERC to share information and encourage them to begin planning for compliance and reliability as early as possible. This effort to identify and respond to any projected local and regional reliability concerns will inform decisions about the timing of retirements and other compliance strategies to ensure energy reliability. The EPA believes that the ability of permitting authorities to provide an additional 1 year beyond the 3-year compliance time-frame as specified in CAA section 112, along with other compliance tools, ensures that the emission reductions and health benefits required by the CAA can be achieved without any risk of adverse impacts on electricity system reliability.

Comment 69: Several commenters (17403, 17716, 17821, 17902) note that delays are expected due to the number of involved stakeholders (state public utility commissions, RTOs, NERC, FERC, DOE, EPA).

Response to Comment 69: Some commenters thought that there would be delays in compliance with this rule attributed to the numerous stakeholders who would be involved. With proper planning, we believe that the compliance schedule established by the CAA can be met. As stated above, there are already tools in place (such as integrated resource planning, and in some cases, advanced auctions for capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as the proposed rule. In addition, the EPA itself is reaching out to key stakeholders including not only sources with direct compliance obligations, but also groups with responsibility to assure an affordable and reliable supply of electricity including state Public Utility Commissions (PUC), Regional Transmission Organizations (RTOs), the National Electric Reliability Council (NERC), the FERC, and DOE. The EPA intends to continue these efforts during the implementation of this proposed rule. The EPA understands that FERC and DOE will work with entities whose responsibility is to ensure an affordable, reliable supply of electricity, including state PUCs, RTOs, the NERC to share information and encourage them to begin planning for compliance and reliability as early as possible. This effort to identify and respond to any projected local and regional reliability concerns will inform decisions about the timing of retirements and other compliance strategies to ensure energy reliability. The EPA believes that the ability of permitting authorities to provide an additional 1 year beyond the 3-year compliance time-frame as specified in CAA section 112, along with other compliance tools, ensures that the emission reductions and health benefits required by the CAA can be achieved while safeguarding completely against any risk of adverse impacts on electricity system reliability

Comment 70: Several commenters (17402, 17752, 17758, 18428, 19114) note that the word "installed," when attributed to vendors, refers only to the physical construction of the controls but that the reality of control technology installation includes more than that.

Comment 71: Several commenters (17403, 17756, 17820, 17931) ask for additional time to allow for unit/control device testing/optimization after installation.

Response to Comments 70 and 71: The EPA is aware that installation of controls means more than simply manufacturing the device but means that it is installed on the unit.

Comment 72: Commenters 18430 and 18023 note that interstate gas pipelines may need to be expanded to account for EGU fuel supply changes.

Response to Comment 72: The EPA's analysis does not fully support this contention. The use of natural gas to comply with this regulation does increase modestly, by about 3% in 2015. However natural gas generation in 2015 with this rule will be more than 200,000 GWh less than generation from natural gas in 2009. This indicates that the shift to natural gas for compliance with this rule would be very modest and that it could be accomplished mostly with existing capacity.

Comment 73: Commenter 17815 notes that the short compliance timeline will jeopardize fuel diversity.

Commenter 16850 states that over the past 20 years, the vast majority of new capacity additions in Florida have been natural gas-fired. The proposed Air Toxics rule, the recent Cross-State Air Pollution rule, potential greenhouse gas regulations, and currently low gas prices may further encourage utilities to install natural gas-fired generation or repower existing oil- or coal-fired capacity to natural gas as a compliance strategy. In order to provide Florida's consumers with the benefits of a balanced fuel mix, utilities should be allowed to retain existing coal capacity without installing costly air compliance measures, if the utility commits to retire or repower the unit in the near future.

Commenter 17887 states that the EPA should recognize the needs of each state and region to deploy a portfolio of cost-effective supply- and demand-side resources based on unique circumstances – Over the past twenty years, the majority of new capacity additions in Pennsylvania have been natural gas-fired. Many states in the PJM footprint including Pennsylvania are actively encouraging the development of renewable resources such as wind and solar. In order to provide Pennsylvania customers with the benefits of a balanced fuel mix, generators should be allowed to retain existing coal capacity without installing costly air compliance measures, if the generator commits to retire the unit in the near future due to the availability of "cleaner" generation resources. Further, the EPA should retain the limited use provision that appears to allow generators to avoid installing costly controls on units that are rarely dispatched.

Comment 74: Several commenters (16549, 17403, 17682, 17917) are concerned that the rule will weaken reliability by removing coal-fired units as a resource. Commenter 16549 believes that that the EGU MACT may make it impossible to utilize the U.S.'s vast supply of coal. Commenter 17917 believes the proposed rule threatens both existing facilities and future development of coal-fired EGUs. Commenter 17682 believes that the EPA is intentionally trying to increase the compliance costs for coal-fired plants to force coal plants to either close or be replaced by other sources, such as gas-fired EGUs and renewable energy alternatives (solar, wind, biofuels). This commenter believes the EGU MACT amounts to a subsidy of alternative energy industries and is defacto tax on the public. Commenter 17403 coal-fired retirements would have a significant impact on key midwestern and south Atlantic states.

Comment 75: Commenter 17386 expresses concern that the proposed rule would decrease generation capacity by forcing early retirement of oil-fired EGUs. This commenter believes that forcing early retirement of oil-fired EGUs and the consequential decrease in generation capacity and system reliability is contrary to NERC's objective to provide reliable service.

Comment 76: Several commenters (17701, 17791, 17807) are concerned that environmental regulations for EGUs will drive electric generators to a single fuel source, which they argue could unintentionally weaken the stability of the power sector and increase cost for consumers. Commenter 17807 believes that the EGU MACT may result in electricity supply problems in Florida because the state is a peninsula, which limits opportunities to import power. The commenters note that fuel diversity is critical for electricity reliability in Florida, where supply problems may be particularly acute during extreme weather events like the recent cold snaps and hurricanes, when supply of natural gas may not be available for sustained periods of time.

Comment 77: Commenter 16850 notes that significant controls would be necessary at many of Florida's coal- and oil-fired generating units, and some units would be at risk of retirement. The commenter states that the EPA's final rules should avoid compromising electric system reliability and allow the maximum compliance flexibility for electric utilities provided for under the CAA.

Commenter 18500 states that the EPA has also asserted that fuel switching of existing EGUs to natural gas and construction of new gas-fired generating units can replace the retired coal units but that the planning, contracting, permitting, financing and construction take longer than the restrictive timeframe proposed, and during that timeframe, some units are not available for dispatch. The commenter states that not all units will have ready access to sufficient gas supply to repower resulting in necessary gas transmission upgrades that can be time consuming and costly. According to the commenter, the reality is that the EPA's own permitting rules present a time consuming obstacle to meeting the EPA's deadline yet nowhere in the proposal does the EPA contemplate addressing accelerated permitting for pollution controls or exemptions from NSR requirements when making pollution control upgrades.

Response to Comments 73 - 77: The EPA does not dictate the compliance strategy that might be used by regulated companies. The EPA has carefully designed a rule that can be achieved by all coal types. Although the EPA's analysis indicates that most plants will comply by retrofitting existing coal-fired plants with pollution controls, some may switch to cleaner fuels. Our analysis shows that in fact there is very little difference in the relative use of the three major coal ranks with and without the rule in 2015. There is a slight increase in the use of interior bituminous coal and a slight decreases in the use of subbituminous and lignite coals. Over all, coal remains the most important fuel for electricity generation.

Some plants may retire. In most cases there is adequate excess capacity to avoid any threat of a problem for electricity reliability. Should there be a reliability concern, it can be addressed in a variety of ways including use of excess capacity, installation of new capacity, transmission upgrades, and demand-side strategies that can make over all compliance with this regulation much less expensive, and can be implemented relatively rapidly. The EPA projects that this rule will result in a very small increase in gas-fired generation, a very small decrease in coal-fired generation as a result of compliance with MATS.

Comment 78: Commenter 17732 is concerned about the time it takes to receive land use approvals on Indian trust lands should site-specific constraints necessitate use of additional land.

Response to Comment 78: Sources can obtain an additional year to comply if necessary for the installation of controls. Unavoidable delays in obtaining permits necessary to install the controls would likely be sufficient to obtain the additional year to comply.

Comment 79: Commenter 17738 is concerned about plants which already have emissions controls and limitations established through case-by-case MACT determinations. The commenter suggests alternate compliance dates for these plants.

Response to Comment 79: Sources that are existing sources on the compliance date for the final rule would have 3 years to come into compliance. Generally these are newer plants that have pollution controls and should be well positioned to comply with this regulation.

Comment 80: Commenter 17386 recommends that the EPA and generation owners collaborate to develop and meet timelines while monitoring equipment installation to avoid negative impacts of delays that could occur. According to the commenter, such an approach would also ease concerns over grid security caused by mass outages on generators to install the required equipment

Response to Comment 80: The EPA's analysis does not confirm that MATS will result in anywhere near the extent of outages that this commenter projects, and several outside analyses have reached conclusions consistent with the EPA's analysis. The EPA does agree, however, with the commenter that a collaborative approach between the companies, the EPA, state regulators, RTOs and others involved in assuring grid stability would help to assure grid security.

Comment 81: Commenter 17930 stated that the EPA's beyond-the-floor analysis [for Hg at facilities burning virgin low BTU coal] does not properly take into account the effect that the limit would have on energy requirements and reliability when lignite units are closed due to inability to meet the proposed beyond-the-floor limit.

Response to Comment 81: As stated elsewhere, the EPA believes that the data used to conduct the beyond-the-floor analysis are consistent with results achieved in U.S. DOE Hg control technology demonstration projects. The DOE's National Energy Technology Laboratory (NETL) sponsored a project entitled "Mercury Control for Plants Firing Texas Lignite and Equipped with ESP-wet FGD". In this project, URS Group evaluated sorbent injection for Hg control in an 85/15 blend Texas lignite/PRB-derived flue gas. The authors of the final project report noted that, in short term parametric tests, three different brominated sorbents performed similarly with results indicating that 90 percent reduction of Hg was attainable at injection rates of 2 to 3 pounds per million actual cubic feet (lb/Macf) and greater than 90 percent at higher rates. In longer-term (60-day) testing using a brominated sorbent, Hg removal averaged 80 percent at a modest injection rate of 2 lb/Macf. This compares favorably to the results of 70 to 90 percent achieved in the short-term testing at the same injection rates. However, greater than 90 percent could have been achieved at injection rates of 3 to 5 lb/Macf. Note that all of these results are for control across a cold-side ESP. Control across a fabric filter is normally expected to exceed that measured through an ESP. The EPA believes that its beyond-the-floor analysis is appropriate, including the costs analyzed. We do not anticipate any reliability problems due to lignite plants closing. Any shift away from lignite is made up for by other types of generating capacity and shifts to PRB.

Comment 82: Commenter 18033 said that the EPA has committed a "fundamental error" with its "undocumented and unsupported claims of key stakeholder collaboration to 'safeguard[ing] completely against any risk of adverse impacts on electricity system reliability'." The commenter could not find evidence of these consultations in the rulemaking docket.

Response to Comment 82: The docket will include documentation of all substantive meetings with persons outside of the executive concerning this rulemaking.

Comment 83: Several commenters (17627, 18034, 18037, 18907) are concerned that the reduced reliability resulting from the EGU MACT may result in an increase in emissions because industry will be forced to rely on small emergency generators. These commenters note that most of the emergency generators are small diesel-fired units that are not capped or in many cases permitted. The commenters note that higher emissions from these emergency back-up generators are not normally a concern because of their limited use during emergency situations and power outages. According to the commenters, if demand response programs become a necessary strategy to prevent or minimize the impact of reliability issues resulting from loss of capacity, however, then localized net increases in emissions would be expected. Rather than improving air quality, the commenters argue that this rule would directly and adversely impact citizens in the urban cores where emergency generation is typically located.

Commenter 18037 stated that in its analysis of this year's capacity auction results, PJM noted that the coal plant offers which included anticipated environmental compliance costs, likely did not clear the market because they were high relative to demand response (DR) offers. According to the commenter, this raises an important environmental contradiction and an issue that the EPA should consider in it cost -benefit analysis. The commenter states that ISO-RTO estimates that are available suggest that 50% or more of DR resources in the market are not demand reductions, rather they are merely a shift to customer-supplied behind-the- meter generation, and much of that generation is from small diesel units the emissions from which are not accounted for and in many cases not permitted. According to the commenter, this is particularly important on very hot, 'high electric demand days" when DR generators are called upon. The commenter states that as the EPA was informed by the State of Delaware in the RICE NESHAP docket (EPA-HQ-QAR-2008-0708), there are tens of thousands of these diesel generators throughout the Northeast.

According to the commenter, these "area sources" emit air toxics and are an increasingly significant contributor to the ground level ozone non-attainment problem as DR programs continue to grow exponentially; they represent tens of thousands of megawatts in the PJM, ISO-New England, New York ISO, Midwest ISO wholesale markets and throughout the US. The commenter states that at a minimum, since EGU units are clearly being displaced in the competitive markets by DR offers, and will not likely be replaced megawatt-for-megawatt by cleaner, more expensive thermal generation which must control and account for its emissions, the EPA's cost-benefit analysis is incomplete if it does not account for the growth in emissions from behind-the-meter generation participating in ISO-RTO DR programs, particularly those from uncontrolled diesel units.

Response to Comment 83: Not all demand response is a reduction in electricity demand, much of it shifts demand for electricity from peak demand periods to periods of lower demand thus reducing the need for peaking capacity. The commenter is talking about a use of generation from small diesel units during periods of peak demand. These units, not subject to this regulation, and may be responsible for increases emissions of pollution. The Reciprocating Internal Combustion Engine rulemaking which was final in March of last year, but which is under reconsideration, limits the operation of these sources, specifically to prevent an increase in emissions. These generators are less efficient to operate than other sources and thus are less desirable economically as well as environmentally. The EPA does not expect that the Mercury and Air Toxics Standards rule will substantially increase the use of these generators.

Comment 84: Commenter 18538 believes that the EPA has overstated the amount of generation available in future years by more than 10 GW by including generating plants that have retired and by failing to adjust wind generating capacity to account for the fact that wind is variable and often does not blow during times of peak energy use.

Response to Comment 84: The EPA disagrees with the claim that it does not account for the variability of wind generation in its power sector modeling projections. The EPA recognizes that wind is a variable resource for power generation, and our modeling of MATS in fact takes this reality into account in a very detailed manner to simulate future generation from wind turbines. The EPA's power sector modeling utilizes capacity factors for wind generators that reflect both wind class (ranging from class 1 to class 7) and geographic region, and are explicitly designed to represent how often the wind blows to support power generation at different locations. The EPA worked with the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL) on a complete update of the wind resource assumptions for use in EPA's IPM v.4.10. The result is a complete representation of the potential onshore, offshore (shallow and deep) wind generating capacity (in MW) broken into four cost classes in each IPM model region.

To represent intermittent renewable generating sources like wind and solar, the EPA's IPM modeling (including the modeling used for MATS compliance cost projections) uses generation profiles which specify hourly generation patterns for a representative day in winter and summer. Each eligible model region is provided with a distinct set of winter and summer generation profiles for wind, solar thermal, and solar photovoltaic plants, such that projected generation from intermittent renewable sources would reflect the frequency that those resources are actually available in that region. The EPA derived its capacity factor assumptions for wind generation from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2010. They are shown in Table 4-20, Table 4-21, and. Table 4-22 of the IPM documentation on EPA's website. See IPM documentation.

Comment 85: Several commenters (17800, 17807, 17911) believe that the work practice standards will impact the reliability of electric supply. These commenters argue that most EGUs do not have annual planned outages that would allow time for implementing the work practice standards. Commenter 17800 states that most planned outages are more than 18 months apart and planned major outages are typically 3 to 5 years apart. The commenter further notes that by requiring outages every 18 months, the EPA will increase the number of outages and thus unit downtime. The commenter notes that inspections of burners for coal fired units require an internal boiler inspection, which means that an outage of at least 15 days will be required (with 1-2 days to cool; 5 days to erect scaffolding; 2-5 days to repair or replace burner components; 3 days to dismantle the scaffolding). According to the commenters, additional time may also be required to order replacement parts, which could result in an extended outage of between 16 to 26 weeks.

Response to Comment 85: The EPA does not believe work practice standards will impact reliability and notes that the frequency of the tune-ups required have been changed in the final rule. *See* Preamble discussion of work standards.

8. Survey of public power utilities.

Comment 86: Commenter 17868 shared results from a survey it conducted of public power utilities (utilities owning approximately 14 GW of coal based generation capacity responded to the survey). According to the commenter, these represent over 50% of the coal-based capacity wholly owned by public power utilities, and respondents ranged in cumulative capacity between 55 MW and 2200 MW, and averaged 610 MW of coal based capacity):

a. About 20% of respondents planned to retrofit FGD and about 20% SCR (typically the same utilities were retrofitting both). About one-half planned to replace or supplement existing ESPs with new FFs

b. About one-fourth were moving forward with plans based on the notice of proposed rule (NOPR).

c. Half were waiting until the final rule is promulgated, and the rest intended to wait until other pending environmental rules were finalized before deciding on a compliance approach.

d. About three-fourths of respondents stated that they needed the assistance of engineering consultants for planning their compliance strategy. Such reliance is not unusual, even for IOUs, but several respondents cited their small size and/or remote locations as barriers to obtaining assistance from the larger, more qualified consulting firms. Additionally, several respondents cited a mandatory ―public bid process for selecting contractors (and purchasing equipment) which deterred some contractors and created additional delays in reaching compliance.

e. Public power utilities generally must receive approval from political bodies, such as an elected Board of Directors and a City Council. Procedures vary by utility, but separate government approvals may be required for the compliance plan and the issuance of bonds to pay for the compliance projects. Several respondents noted that a public referendum is required in order for bonds to be sold.

f. Planning periods averaged 17 months, and financing 8 months. However several respondents noted that budgets were addressed only once per year, and that public reviews of plans and funding could result in extended delays, including what one respondent called "hostile interventions."

Response to Comment 86: The EPA recognizes that many plants that are owned by public power authorities are well controlled and, thus, are well positioned to implement this rulemaking. Some of them, however, may have challenges privately owned facilities do not have. We think that the flexibilities that are offered under the CAA including the availability of a fourth year and other compliance time flexibilities will ease the burden these facilities face.

9. Other.

Comment 87: Commenter 18027 notes that the language in section 112(i)(3) is inconsistent across paragraphs. Section 112(i)(3)(B) provides for a one-year source-specific extension to the principal compliance schedule established for the source category or subcategory whereas the preceding paragraph states that Congress provided for the compliance schedule established upon promulgation of the standards to apply to an entire category or subcategory of sources.

Response to Comment 87: The EPA does not agree with the commenter that the CAA section 112(i)(3) paragraphs are inconsistent. CAA section 112(i)(3)(A) authorizes the EPA to provide up to 3 years for initial compliance with promulgated standards, and section 112(i)(3)(B) allows the EPA or a state with an approved title V permit program to approve a 1-year extension of the compliance period established in the final rule if such time is necessary for the installation of controls.

5C02 - Compliance: Emissions Averaging

Commenters: 17174, 17402, 17623, 17627, 17648, 17655, 17689, 17691, 17705, 17714, 17716, 17718, 17719, 17722, 17725, 17730, 17731, 17736, 17737, 17740, 17757, 17758, 17768, 17774, 17775, 17789, 17795, 17798, 17800, 17813, 17816, 17818, 17820, 17821, 17856, 17870, 17873, 17877, 17881, 17885, 17902, 17904, 17913, 17928, 18014, 18024, 18025, 18031, 18037, 18429, 18449, 18450, 18498, 18539, 19114, 19120, 19121, 19214, 9738, 19536/19537/19538, 18023

1. Opposition to emission averaging compliance option.

Comment 1: Commenter 17174 states the emissions caps for existing affected sources choosing to demonstrate compliance by the emission averaging option cannot be effectively implemented or enforced. The commenter encountered many problems with the approval process in the vacated Boiler MACT in 2007, and now the EPA has proposed the same approval process here for the Utility MACT, disregarding the known problems in implementing the emission averaging compliance option from the Boiler MACT. The commenter stated the emission cap should be included in the compliance calculations. The commenter believes that the requirement to establish an emission cap and submit an implementation plan to the permitting agencies for approval is problematic as written. The commenter states that because the emission cap is not used in the initial compliance demonstration or in demonstrating continuous compliance with the emission averaging option, the commenter states it is of little use. The commenter states that if the intent of this option is for facilities to not exceed the cap at any time, then the EPA should include a demonstration methodology that shows that a facility is not exceeding the cap in the compliance equations in section 63.10009. According to the commenter, if the cap is included in the compliance equations, facilities could certify compliance with the cap in the NOCS and within each required semiannual report. The commenter went on to say that if the initial and continuous compliance measures include the emission cap, the implementation plan will not be necessary and states will not have to spend valuable time and resources to approve these duplicative plans.

Response to Comment 1: The agency disagrees with the commenter’s suggestion that the emissions averaging option cannot be implemented or enforced effectively. The commenter’s concerns regarding emissions averaging plan approval is mistaken, as such an approval is required only if requested by the Administrator. While the plan may not need to be submitted for approval, the EGU owner or operator who wishes to use emissions averaging will need to develop, maintain, and make available a plan. Emissions from EGU units included in averaging, as opposed to individual EGU units, are not to exceed the otherwise applicable emissions limit. Deviations from meeting this requirement are already required to be submitted in notices of compliance status (NOCS), so no rule change is needed. Finally, states, local, or tribal agencies who are delegated the authority to implement this program will decide based on their own needs and requirements whether or not to choose to require submission and approval of plans.

Comment 2: Commenter 17818 opposes the averaging of HAP. However, the commenter supports allowance of limited emission averaging for existing units at sources that are within a single subcategory. Commenter further states that without averaging their existing units are already below existing HAP emission rates due to previous emission control projects, some of their units will be above new HAP emission rate limits and would require redesign of the existing controls to achieve unit-specific compliance. According to the commenter, averaging of units might facilitate state-of-the-art highly effective controls installation on other units at the source to achieve an approved averaging plan, and this may relieve the need to replace or modify controls that had been recently installed, in effect giving credit for the installation of those controls.

Response to Comment 2: The agency agrees with the commenter that emissions averaging can provide a cost-effective, if not cost-saving, means of compliance, to EGU owners or operators. The emissions averaging provisions of the rule remain.

Comment 3: Commenter 18450 opposes allowing owners and operators of existing affected sources to demonstrate compliance by emissions averaging for units at the affected source that are within a single subcategory since it will allow large facilities to avoid installing air pollution controls to reduce HAP emissions on all affected units. Commenter recommends that the EPA remove the averaging provisions and establish a discount factor to compensate for the measurement variability inherent in stack testing for HAP.

Response to Comment 3: As mentioned in an earlier response, the agency supports the use of emissions averaging for existing sources for a number of reasons, ranging from increased flexibility to reduced costs for EGU owners or operators, as well as reduced emissions through use of a discounted emissions limit for those units subject to emissions averaging. The EPA disagrees that use of a discount factor is needed for this rule, as stack testing variability has already been incorporated in the rule's emissions limits via use of the UPL calculation.

Comment 4: Commenter 19214 opposes the proposed average emission limits among multiple sources at facilities in the Best Available Retrofit Technology (BART) program. The commenter states that even though it appears to satisfy the criteria established by the EPA, in practice, it works only if all affected sources operate exactly as assumed in the formulation. According to the commenter, realistically, the better-controlled source may operate less than assumed (perhaps due to the greater costs of compliance), while the under-controlled source uses cost advantage to operate more than assumed. Commenter believes that the risks that actual emissions and potential human health and environmental effects will be greater than assumed, and not worth providing more flexibility to emit hazardous air pollutants.

Comment 5: Several commenters (19536, 19537, 19538) states that the EPA should not permit units to average emissions. According to the commenters, the proposed averaging would allow some coal- and oil-fired units to emit HAP in excess of the promulgated standards (so long as a neighboring unit operates below the standards) – a result prohibited by section 112. The commenters state that section 112 states that "[a]fter the effective date of any emissions standard . . . promulgated under this section and applicable to a source, no person may operate such source in violation of such standard" unless the agency provides a more lengthy compliance schedule. 42 USC section 7412(i)(3).

The commenters point out that the agency's discretion to construe the word "source" under the CAA is constrained by the congressional policies underlying section 112. *Chevron, U.S.A. v. Natural Resources Def. Council*, 467 U.S. 837, 866 (1984). The commenters state that Congress intended, in section 112, to ensure the maximum reduction of hazardous air pollution, and to that end, it constrained the agency's ability to balance pollution-reduction with economic considerations. See 42 USC section 7412(d). The commentesr assert that the agency has set most standards at the statutory minimum. According to the commenters, section 112 does not allow the agency to permit additional pollution in order to ease compliance (see 40 CFR section 63.41 (sources may not average emissions to avoid compliance with section 112 standards).

Response to Comments 4 - 5: As mentioned earlier, while the agency has reviewed the commenter's concerns, the agency finds emissions averaging when coupled with appropriate safeguards such as those contained in the rule, including eligibility (existing units within a single subcategory) and frequent emissions verification (quarterly) can provide a flexible, cost-effective compliance approach.

2. Support emissions averaging compliance option.

Comment 6: Numerous commenters (17402, 17623, 17648, 17655, 17705, 17716, 17718, 17722, 17725, 17758, 17774, 17798, 17870, 17873, 17904, 17928, 18025, 18031, 19121, 18023) support emissions averaging for compliance.

Response to Comment 6: The agency appreciates the commenters' support for use of emissions averaging subject to the rule's eligibility requirements.

Comment 7: Commenter 17174 requests the EPA eliminate the requirement for delegated authorities to approve implementation plans and instead develop an emission averaging certification mechanism within the Notice of Compliance Status (NOCS), because the NOCS process is established, and states have experience implementing it.

Response to Comment 7: As mentioned earlier, the rule allows, but does not require, delegated authorities the ability to approve emissions averaging plans.

Comment 8: Commenters 17402 and 17648 note that emission averaging provides a flexible approach. Commenters also note that emission averaging achieves equivalent MACT emissions limits. Commenter 17402 states that facility-wide averaging will allow owners and operators to comply with emissions limits by over controlling sources within the group where it is cost effective to do so in order to offset exceedances of the standard by sources for which emissions control would be less cost efficient.

Response to Comment 8: The agency appreciates the commenters' support for use of emissions averaging subject to the rule's eligibility requirements.

Comment 9: Commenter 17174 states the requirement for delegated agencies to approve implementation plans is burdensome and unnecessary. The commenter suggests the EPA should provide specific guidance and examples on what constitutes an acceptable emission cap. The commenter notes that while the EPA attempted to correct the enforceability problem related to the emission cap in the final Boiler MACT by requiring facilities to report the emission cap in the NOCS (see 40 CFR 63.7545(e)(5)(i)), and certify compliance with the cap in the compliance reports (see 40 CFR 63.7550(c)(l3)), there is no guidance or clear process on what constitutes an acceptable and enforceable emission cap that delegated agencies can follow to approve the cap. If the EPA decides that the submittal and approval of implementation plans are necessary for the emission averaging compliance option, the commenter believes that the EPA should retain the authority to approve the implementation plans.

Response to Comment 9: The agency finds the commenter's concern misplaced. While the rule allows state, local, or tribal authorities who have been delegated approval of this rule the ability to require submission of, as well as approval of, emissions averaging plans, the rule requires EGU owners or operators who choose to engage in emissions averaging to develop an emissions averaging plan and to maintain and present such a plan upon request. The rule establishes the formula for demonstrating compliance when emissions averaging is used, so there is no need for additional guidance. Should the commenter find developing a plan or determining compliance to be problematic, he or she could choose another compliance option available in the rule.

Comment 10: Commenter 17174 suggests the emission averaging compliance option in the Boiler MACT and Utility MACT be consistent.

Response to Comment 10: The agency agrees with the commenter's suggestion, and the rules are consistent to the extent possible.

Comment 11: Commenter 17798 states that both emissions averaging and staging controls provides flexibilities for utilities having to meet a new stage of reductions under the Cross State Air Pollution Rule (CSAPR).

Comment 12: Commenters (17870, 17873) state that emissions averaging represents an equivalent, more flexible, and less costly alternative to unit-by-unit emissions limits while still maintaining a regulation that is workable and enforceable. According to the commenter, this flexible compliance option will be particularly helpful to smaller generating units that are co-located with larger generating units, but may not be economic to retrofit with pollution control systems.

Response to Comments 11 - 12: The agency appreciates these commenters' support of emissions averaging.

3. Request expanded flexibility for emissions averaging.

Comment 13: Multiple commenters (17718, 17816, 17820, 18037, 18539, 19114) state that the proposed emission rate averaging plan does not provide much flexibility because the emission rate limits are so low. According to the commenters, in order for a source to take advantage of these provisions, at least one unit would need to achieve a rate substantially lower than the MACT limit, and there is no evidence that such rates are achievable for any existing units. The commenters state that the mass-based approach would provide each facility with a total annual mass emission limit for HCl, PM, and Hg that could provide flexibility for the source to operate in the most economical way to meet that facility-wide limit.

Comment 14: Numerous commenters (17627, 17718, 17719, 17737, 17740, 17768, 17774, 17775, 17813, 17816, 17820, 17856, 17885, 17902, 17913, 17928, 18024, 18037, 18539, 19114) state that the averaging provisions should not be limited to units at a facility but should be expanded to include adjacent units that have controlled access within a common fence line. The commenter states that the EPA can provide additional flexibility and cost savings on emission reductions by revising the facility definition to include units within a common fence line. Commenter 19114 suggests that a unit could have the annual mass limit set as a multiple of the design heat input, the HAP limit for each constituent, and the average capacity factor for the unit for the previous 3 years. Commenter 17740 suggests that emissions averaging for units in different subcategories could easily be accomplished by requiring the units to develop an emissions averaging plan, similar to the plan required for NO_X emissions averaging under the Acid Rain Program at 40 CFR 76.11. According to the commenter, such an approach could easily be used in the EGU MACT rule to allow units in different subcategories to meet the HAP emission standards through emissions averaging. Commenter 17928 further states that oil-based units are particularly disadvantaged by the proposed constraints on averaging because they are often stand-alone units that would not be able to average emissions with other units at a facility. According to the commenter, oil and coal units at a facility should be permitted to average emissions.

Response to Comments 13 - 14: The agency reviewed the commenters' suggestions, and the rule continues to allow emissions averaging of a rate, not mass, from existing units within the same subcategory. EGUs in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control), remain eligible under to rule to engage in emissions averaging. Should a commenter find these requirements problematic, he or she may use another of the compliance demonstration approaches contained in the rule.

Comment 15: Commenter 17627 requests that regulated entities should be allowed to bubble emissions from EGUs within a 50 kilometer (km) radius to determine source deposition mercury “hot spots” in *Technical Support Document: National-Scale Mercury Risk Assessment Supporting the Appropriate and Necessary Finding for Coal and Oil-Fired Electric Generating Units* (p. 6). According to the commenter, allowing EGUs to average emissions from regional sources will still reduce the deposition from sources the EPA links to the Hg “hot spots” while also providing additional compliance flexibility for sources that have a limited number of EGUs.

Response to Comment 15: The agency has considered the commenter’s suggestion, but, apart from the contiguous property eligibility criterion mentioned in the rule, emissions averaging from EGUs within a specific area, but not on properties adjacent to each other, will not be allowed.

Comment 16: Commenters (17623, 17655, 17705) indicate that the emission averaging criteria are too rigid. Commenters (17623, 17655, 17757, 17758) request broader applicability and more flexibility in emissions averaging. Commenters (17623, 17758) believe the limiting criteria for emissions averaging provisions is too rigid to provide significant flexibility or cost reductions. Commenter 17623 notes the inflexible structure is not needed because all facilities will collectively be subject to the same emissions limit and all required reductions would occur. Commenter 17758 indicates that the EPA does not provide details as to why it has determined that a broader approach would lessen the MACT floor, does not enumerate any of the implementation or enforcement issues that could arise from allowing emission averaging in any of the scenarios the rule bars, and this lack of information deprives commenters the opportunity to assess, comment on, and address the EPA’s concerns. Commenter 17758 went on to state that the EPA does not explain why emission averaging provisions or limitations that were applied in other MACT rules are applied in Utility MACT or what characteristics of those other sources are comparable to Utility MACT sources (i.e., why are limits that were deemed necessary for synthetic organic chemical manufacturing appropriately applied to electricity generation). In fact, commenter 17758 states that the EPA appears to assume that past rulemaking limits applied to emissions averaging create an enforceable “criteria” that must be satisfied in this rule for utility generators. Commenter 17758 states that the EPA has not explained why any of the additional limiting criteria are needed if the owner or operator can demonstrated that total averaged emissions do not exceed the limits that would be applied to individual units. Commenter 17758 states the EPA has not demonstrated that limiting the use of emissions averaging would obviate the unspecified implementation and enforcement issues that the EPA suggests are of concern. Commenter 17758 further states the EPA fails to recognize the compliance and enforcement difficulties that would be created by imposing the proposed limitations on averaging; for example, it would be substantially more complicated and expensive to segregate, measure separately, and monitor the emissions of units that share a common stack to determine that each is in continuous compliance with the MACT standard for a particular pollutant than to allow these units to use averaging by measuring common emissions from the stack.

Response to Comment 16: The agency has considered all but disagrees with most of the commenters’ assertions and notes that the commenters provide no data to support their assertions. We specifically disagree that broader averaging is consistent with the statute as explained in the preamble to the HON NESHAP:

> The fundamental problem with the broader averaging approach[, beyond sources in the same category or subcategory,] is that it allows averaging among multiple sources. The HON has defined the source, for the purposes of this standard, as the collection of SOGMI emission points within a major source. Many major sources containing such points will also contain other points not covered by this standard but to be covered by later, different MACT standards. Each of these standards will have a separate floor, and the statute requires that each standard be no less stringent than its floor. If averaging were allowed between sources covered by two separate standards, it is likely that one of the sources involved in the average would be emitting HAP's at a level that violates the standard applicable to it. Thus, averaging between multiple sources in different categories is not legally defensible.
>
> Similarly, allowing averaging between new and existing sources at the same facility would also likely lead to one source failing to meet its applicable standard. There are separate MACT standards with separate floors for new and existing sources within the HON, just as there will be separate standards for sources in different categories at the same site. An average that included sources with different floors and different standards cannot be reconciled with the statutory requirement that each source in the category comply with the applicable standard.
>
> 59 FR 19427 (April 22, 1994)

Based on the long standing interpretation of the statute, the rule is unchanged. Further, we note that commenters appear to presume that the agency must justify not allowing averaging on a broader level, but such an assertion is not valid. CAA section 112 does not expressly authorize averaging and the final rule would be consistent with the statute absent any allowance for averaging. The EPA's policy concerning averaging is based in part on our interpretation of the statute and commenters have not provided a viable alternative interpretation, nor have the commenters provided information that would call into question our policy justifications for limiting averaging in the manner proposed. That certain EGU owners or operators may not be able to avail themselves of the emissions averaging options (e.g. because they vent units in different subcategories to a common stack) or may choose not to because they determine that the potential benefits of averaging do not justify compliance with the requirements to average does not render the provisions invalid.

Comment 17: Several commenters (17623, 17627, 17689, 17736, 18037) state that limiting emissions averaging to only units in the same subcategory shrinks the universe of sources that can use this option. Commenters 17655 and 17757 encourage the EPA to allow averaging between units at different facilities that are under the same/common control and operating in the geographic region or at adjacent facilities. Commenters 17655 and 17881 encourage the EPA to allow averaging new unit emissions with existing unit emissions. Commenter 17623 states that not allowing new facilities to participate puts new generation capacity at a disadvantage and reduces the effectiveness of the averaging program. Commenter 17623 states that allowing emissions averaging for new facilities will incentivize installation of state-of-the-art controls on new units. Commenter 17655 disagrees with the EPA's argument that allowing new and existing averaging would be too cost effective and states this argument would not stand up to a test of arbitrariness. Commenters 17758 and 18037 suggest the EPA allow emissions averaging across all affected units (both coal and oil) on a facility basis, including both new and existing units and where averaged units share a common stack. Commenter 17758 suggests the EPA allow broader emissions averaging where it can be demonstrated that public health and environmental benefits are preserved. Commenter 17881 states that averaging across multiple new EGUs would minimize the risk of startup, shutdown or malfunction at a single unit resulting in an exceedance of an applicable emission limit.

Response to Comment 17: As mentioned earlier, the agency believes emissions averaging subject to certain unit eligibility criteria, including existing units within the same subcategory using emissions testing on contiguous properties under common control, in the rule can provide a cost-effective, flexible, environmentally-friendly means of demonstrating compliance. Other suggestions, such as including new units that can be designed for appropriate emissions control devices from the onset or mixing units from differing subcategories with differing emissions limits, are not consistent with the statute as discussed above and, in any case, we do not believe such averaging would be appropriate in any case. The rule has not been revised for these suggestions. Note that the final rule contains work practice standards during periods of startup or shutdown.

Comment 18: Commeter17758 states that the EPA previously proposed emissions averaging for EGUs in its 2004 proposed standards and the rationale for including this option remains valid.

Response to Comment 18: The agency thanks the commenter for his support.

Comment 19: Commenter 17705 believes EGUs should be allowed to average actual emissions data from CEMS to determine monthly average weighted emissions for the units participating in an averaging plan, as this simplifies the demonstration of compliance.

Comment 20: Commenter 17705 notes that section 63.10022 requires facilities using emissions averaging to also comply with operating limits for control devices and fuel limitations for Hg and chlorine on top of numeric stack emissions standards. Commenter 17705 states this burden can be alleviated by allowing an averaging plan that based on CEMS usage, as CEMS data is a more accurate indicator of continuing compliance with a numeric standard than operating limits set during periodic performance tests or fuel analyses.

Comment 21: Commenter 17705 stated that the availability of the alternate SO_2 standard coupled with use of emissions averaging based on use of existing certified CEMS is likely to be a preferred compliance option for sources with existing FGD technology and should be fully accommodated in the final rule language.

Response to Comments 19 - 21: The agency supports the commenters' suggestions regarding use of CEMS for units subject to emissions averaging, and the rule has been revised so that units that use CEMS can participate in emissions averaging. Note that, as stated elsewhere, the rule no longer requires fuel analyses for pollutants.

Comment 22: Commenter 17402 notes emission averaging is permitted under section 112 and there is ample precedent for allowing it. Commenter 17402 notes the emissions averaging is permitted under section 112(d) of the CAA(particularly given the important limitations included in the rule) and there is ample precedent for allowing such facility-wide emissions averaging (cites 6 part 63 NESHAP rules with emissions averaging). Commenter 17758 further indicates that the CAA provides flexibility in allowing emissions averaging broadly and does not direct the agency to promulgate standards that are applicable unit-by-unit or facility-by-facility; the CAA does not mandate that the EPA apply MACT standards on an individual unit basis; CAA section 112(d)(1) provides that the EPA shall promulgate regulations "for each category or subcategory of major sources and area sources of hazardous air pollutants..." (emphasis added); and CAA section 112(d)(2) standards are applicable to "new or existing sources" (emphasis added).

Response to Comment 22: The agency acknowledges the commenters' support for emissions averaging and for the agency's discretion in designing emissions averaging provisions according to program needs. No changes to the rule regarding expansion of emissions averaging across subcategories or to new units were made.

Comment 23: Commenters (17402, 17655) support weighting by heat input (based on the performance test results). Commenter 17655 agrees that existing DAHS can perform these calculations and produce reports.

Response to Comment 23: The agency thanks the commenters' for their support of weighting emissions rates by heat input.

Comment 24: Commenter 17648 supported the four criteria required by the EPA to participate in emissions averaging and went on to state that the EPA should also apply a discount factor to assure that emissions from the affected sources as they are actually controlled will be at least as stringent as the total sum of emissions that would be achieved if each unit at an affected source were controlled individually to the level required by the rule, as it has done in prior NESHAP.

Response to Comment 24: The agency disagrees with the commenter's support for use of a discount factor, for under the emissions averaging procedures contained in the rule, each group of units subject to emissions averaging will have to meet the emissions limits of a specific subcategory. While these emissions limits would otherwise apply on an individual basis, through emissions averaging, the group's total emissions will be no greater than the sum of the emissions from individual units. Note that the emissions from units that engage in averaging under this rule are not bound by a cap, but by the otherwise applicable emissions limit. The rule does not include a discount factor.

Comment 25: Commenter 17774 states that disallowing the new facilities from emission averaging puts new generation capacity at a disadvantage and reduces the effectiveness of the program. According to the commenter, units subject to the NSPS would have to continue to comply with the individual PM limits in that rule even if the emissions averaging option is used, further reducing the utility of the option.

Response to Comment 25: The agency disagrees with the commenter, and the rule continues to exclude new units from emissions averaging. As mentioned in the preamble to the HON rule (see 59 FR 19425), the agency does not believe the statute authorizes emissions averaging for new affected sources. In addition, it is most cost effective to integrate state-of-the-art controls into equipment design and to install the technology during construction of new sources so, even if we concluded that such averaging was authorized, we would decline to allow averaging of new sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion. This flexibility is not needed for new affected sources because they can be designed and constructed with compliance in mind.

Comment 26: Commenter 17798 recommends initial emission averaging by utility ownership and state staged to facility averaging 2 years later. The commenter states that the EPA provides a mechanism in the NESHAP rule for the agency to approve a 1-year compliance extension on an EGU sector-wide basis.

Response to Comment 26: The agency considered the commenter's recommendation, but did not change the rule to allow phase-in of emissions averaging. An EGU owner or operator will need to have his or her emissions averaging plan developed and results of all testing in hand on or before 180 days after the unit's first compliance date in the rule.

Comment 27: Commenter 17881 states that in section 63.10006(o) if emission limits are consistently being met, then reduced frequency of testing should be allowed for the units utilizing emissions averaging.

Response to Comment 27: The agency disagrees with the commenter, and the rule continues to exclude those units associated with emissions averaging from reduced emissions testing frequency.

Comment 28: Commenter 9738 states that the inclusion of an alternative compliance provision within the proposed rule that would allow owners and operators of existing affected sources to average the emissions by sources within the same category allows more flexibility for owners. According to the commenter, this may increase the feasibility of the compliance deadlines in two ways: First, if cost is a concern, owners and operators may be able to strategically implement technology to bring their plant into compliance on only some of the smokestacks. The commenter states that while this could ultimately balance the total emissions of the plant, it would require the owners and operators to raise fewer funds, which should thus decrease the amount of time needed to prepare fiscally for the new standards. The commenter states that second, if an owner or operator chose to selectively implement such technology, less work would need to be performed, as only a portion of the smokestacks would require retrofitting. Thus, according to the commenter, this should also require less time to bring the facility into compliance, and this alternative provision allows for companies to strategically stagger their compliance efforts and increases flexibility. The commenter states that further, for facilities which have already implemented some such technology, this alternative provision may eliminate the need for additional action. According to the commenter, this would achieve the goals of the proposed bill by promoting the same reductions in emissions, thus having the same societal impact overall.

Response to Comment 28: The agency appreciates the commenter's support of emissions averaging within a subcategory.

4. Clarifications and modifications to emissions averaging.

Comment 29: Commenter 17402 suggests clarifications to improve emissions averaging for compliance. Commenter 17402 notes that section 63.10009(f)(3) and section 63.10022(a)(1) are somewhat contradictory and could be interpreted as requiring compliance in the first month of collecting data. Several commenters (17725, 17402, 17775, 17881) recommend clarifying in section 63.10009(f)(3) that the first compliance period begins after 12 months of data have been accumulated, and in section 63.10022(a)(1) that compliance is demonstrated each month, and that compliance is first determined after 12 months of data are collected. Commenter 17775 states that requiring compliance with both a monthly average and a 12-month rolling average of those values makes no sense.

Comment 30: Several commenters (17821, 17856, 17902) recommend that the EPA allow sources to demonstrate compliance with an averaging plan over a 12-month period and not on 30-day rolling average basis. Commenter 17821 further states that the primary reason for this is that the EGUs require periodic outages for scheduled and unscheduled maintenance. According to the commenter, when a unit is in an outage, the remaining units could be forced to shut down during the same period if compliance with an averaging plan must be demonstrated based on only one month's data. The commenter states that if however compliance with an averaging plan were based on the average of 12 consecutive months, a facility would be in a better position to absorb the effects of individual unit outages over the course of a year. Commenter 17856 further states that revising the rule as suggested would provide needed flexibility to the regulated community, eliminate compliance and enforcement uncertainties, and achieve the same emissions reductions that the EPA seeks.

Response to Comments 29 - 30: The agency has reviewed the commenters' suggestions, and the rule has been revised so that the results of the emissions testing are used for each 30 boiler operating day rolling average during the quarter in which the emissions testing is conducted.

Comment 31: Several commenters (17402, 17775, 17881) recommend operating parameters be removed from the averaging plan required under section 63.10022(a)(2) to (5). Commenters further state that if the operating parameters are required, the averaging period for control devices should be extended from a 3-hour average to a 30-day rolling day average period to account for variable conditions. Commenters recommend that in calculating the ESP power operating parameter, the calculation should use the lowest (or highest) value obtained during the performance test as opposed to the average low (or high) values of the performance testing. Commenter 17881 further states that the references in section 63.10022(a)(2) through (a)(7) to the "3 hour average parameters" established during the performance test does not clearly line up with the requirements of Table 4 or Table 8 and is confusing.

Response to Comment 31: The commenters' suggestions are moot, for the rule no longer requires monitoring of control device operating parameters.

Comment 32: Commenter 17174 states the EPA should clarify the deadline to established emission caps to demonstrate compliance with the emissions averaging option for the emission level or control technology. The commenter notes that section 63.10009(c) and section 63.10009(g)(2)(i) appear to have a contradiction in dates (30 days vs. 60 days), and the EPA should correct this in the final rule.

Response to Comment 32: The agency considered the commenter's suggestion, and the rule now has a consistent date (on 180 days after [INSERT DATE 3 YEARS AFTER PUBLICATION OF THIS FINAL RULE IN THE FEDERAL REGISTER], or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier).

Comment 33: Commenters 17648 and 17881 request clarification of emissions averaging provisions, with assertions that the preamble indicates emission averaging provisions do not apply to units that share a common stack with units in a different subcategory, while the rule text in section 63.10009(h)-(k) is confusing, and arguably may allow sources with units in different subcategories emitting through the same stack to average emissions to demonstrate compliance, without clarifying that all of the other relevant averaging provisions, such as the emissions cap, apply.

Response to Comment 33: The agency considered the commenters' suggestions but the rule is unchanged. What the rule prohibits is units from differing subcategories being included in emissions averaging, not only units from differing subcategories sharing common stacks. The rule provisions cited describe how EGUs sharing common stacks can determine compliance with an emissions averaging program.

Comment 34: Several commenters (17705, 17718, 17737) state the EPA should clarify in sections 63.10009(e)(1) (initial compliance, includes SO_2) and 63.10009(f)(1) (continuing compliance, no mention of SO_2) that the SO_2 surrogate limit as an alternative standard for acid gases can be used under the emissions averaging compliance option.

Response to Comment 34: The agency agrees with the commenters' suggestions, and the rule has been revised to include SO_2 as eligible for emissions averaging.

Comment 35: Commenters 17623 and 17775 suggest the EPA include more flexibility in the submission timing of the emissions averaging plan, and notes that submittal 180 days prior to compliance is a lengthy lead time that limits the effectiveness of the EPA program because facilities may not have yet finished control technology installation to formulate the emissions averaging plan.

Response to Comment 35: The agency considered the commenters' request, and the rule has been revised so that an emissions averaging plan must be developed by 3 years after the rule has been promulgated. In addition, results from all initial emissions testing must be received and ready for use in compliance calculations by 3 years after the rule has been promulgated.

Comment 36: Several commenters (17655, 17718, 17795, 18429) agree that 30-day block averaging should supplant rolling averages in a unit averaging plan, as there are inconsistencies that would accrue from varied operating schedules of the affected units. Commenter 17795 further states that lengthening the averaging period would help achieve the flexibility the EPA intended by granting facility averaging. Commenter 18429 recommends that emissions averaging should be based on annual mass emissions rather than on a rate basis, and should be allowed between any groups of sources that contractually commit to an emissions averaging program similar to the original NO_X compliance program under the Acid Rain Program.

Comment 37: Several commenters (17718, 17775, 17795, 17800, 18031) state that the EPA must clarify ambiguities in the proposed rule and explain exactly how the provisions must be implemented. According to the commenters, it is unclear how to account for units which are shut down for an outage or whether individual unit baseline testing is necessary. Commenter 17775 suggests that in the event of a unit outage, the EPA should allow use of at least a 3-month average. Commenter 17795 further states that if one unit operates slightly above the limits could not operate during the first year of compliance, and the unit used to average it into compliance was in outage, this would negate any benefit or flexibility the EPA intended by incorporating the averaging provision into the proposed rule. Commenter 17800 recommends that the EPA adopt the averaging time of a 12-month rolling average that the State of Illinois has determined to be appropriate in their Mercury Rule. According to the commenter, lengthening of the averaging time would help to account for normal process variations and account for emissions during normal startup, shutdown and malfunction events.

Response to Comments 36 and 37: The agency reviewed the commenters' suggestions, and the rule now allows a 90-boiler operating day rolling average period for mercury emissions from EGUs in the EGUs designed for coal $\geq$ 8,300 Btu/lb subcategory that are included in an emissions averaging group, along with the existing 30-boiler operating day rolling average periods for other pollutants in other subcategories. Should these requirements prove too difficult for an EGU owner or operator, he or she should choose another compliance demonstration option. Note that the final rule includes work practice standards during periods of startup or shutdown, so the request to lengthen the averaging time to account for such periods is moot.

Comment 38: Several commenters (17718, 17737, 17775, 17821, 18031) state that all of the equations (Eq.1, 2, 3 and 4) seem to specify that the emission rates to be used are "determined during the most recent performance test". According to the commenters, the EPA should clarify that if CEMS (i.e., PM, HCl or Hg) are being used to determine compliance with the limits, values from those monitors could be used. Commenter 17775 recommends that the EPA should revise 40 CFR 63.10009 to include procedures for CEMS, and make clear that units using CEMS to calculate average weighted emissions do not have to comply with the operating limits for control devices in proposed 40 CFR 63.10022.

Comment 39: Commenter 17718 states that if SO_2 data via CEMS is being gathered for comparison with the acid gas alternate SO_2 limit, those values should be allowed for use as on a monthly demonstration method for HCl.

Response to Comments 38 and 39: As mentioned elsewhere, the agency agrees that units using CEMS, including SO_2 CEMS, are eligible to participate in emissions averaging, and the rule now clarifies how EGUs using CEMS in emissions averaging are to determine compliance. Those units would use the emissions rate determined from the 30 (or 90) boiler operating day period ending at the end of each month s at the end of each calendar month in their calculations. Note that as mentioned elsewhere, operating limits are no longer required for units using CEMS.

Comment 40: Commenter 17718 recommends that in determining an emission limit from different subcategories that emit from a common stack (40 CFR 63.10009(j)), it would be more appropriate to use the maximum rated heat input (or capacity) for the combined units to allow more flexibility in determining the common stack emission limit.

Response to Comment 40: The agency disagrees with the commenter's suggestion that the rule's emission averaging provisions need more flexibility, and the rule has not been changed.

Comment 41: Commenter 17718 requests the EPA to clarify whether a "pre-test" be conducted so that a comparison can be made between a "30 day after" value and the initial compliance test. The commenter states that the EPA should specify the notification and submittal requirements for such a test and that the EPA should clarify what kind of documentation is needed for the "control technology" option to prove that it has not become "less effective."

Comment 42: Commenter 17881 states that the provisions of section 63.10009(c), require that "the HAP emission rates observed during the initial compliance test must not exceed those being achieved on the date which is 30 days following rule finalization or that the control technology employed during the initial compliance test should not be less effective for the HAP being averaged than the control technology employed on the aforementioned date." According to the commenter, the existing units have no inherent requirement to conduct testing or control device removal efficiency evaluations prior to the compliance date, which is 3 years following rule finalization.

Response to Comments 41 - 42: The agency considered the commenters' suggestions, and as mentioned elsewhere, the rule now clarifies that an EGU subject to emissions averaging must have its emissions results available for use in calculations on or before 3 years, not 30 days, after rule promulgation. Moreover, the rule now clarifies that an EGU owner or operator needs to ensure that the "design efficiency of the emissions control technology has not changed", as opposed to ensuring that the "control technology" has not become "less effective," but does not specify the kind of documentation an EGU owner or operator would be required to provide.

Comment 43: Commenter 17718 states that the EPA should clarify why the presence of an ESP would require monthly fuel content determinations.

Response to Comment 43: The comment is moot, as the rule no longer requires fuel analysis for pollutants.

Comment 44: Commenter 17725 requests revision to the compliance timeframe and the addition of a definition of an oil-fired facility. The commenter states that clarification is needed for dual fuel units to average emissions of oil only units. According to the commenter, the use of interruptible natural gas can offset oil-fired emissions, but the availability of natural gas is often restricted, especially in the winter months and during the summer high demand period, and without a supply of gas in all months, a facility will not be able to use emissions averaging for compliance because it may not meet the proposed limits for the initial 12-month period on a month-by-month basis.

Comment 45: Commenter 17725 requests that the use of liquid fuel should not count towards the site averaging compliance demonstration when the gas supply to the EGUs is unavailable due to factors outside of the facility's control or when the EGU must use oil rather than gas to comply with environmental or market based testing requirements.

Response to Comments 44 - 45: The agency reviewed the commenter's suggestions, but no changes to the rule were made. The rule already defines an oil-fired electric utility steam generating unit, and the rule maintains the eligibility criterion of having only those EGUs in the same subcategory as available for inclusion in emissions averaging. Should the commenter find that his EGUs would be unable to meet all emissions averaging criteria, he or she should use another option to demonstrate compliance.

Comment 46: Commenter 17730 states that the emissions averaging plan is an unnecessary element of the proposed rule and should be eliminated from the final rule.

Response to Comment 46: The agency disagrees with the commenter's assertion, and the requirement to develop an emissions averaging plan remains in the rule. The agency finds such a plan helps the owners and operators understand what is to be done, which units are to be included, and how compliance is to be determined, as well as helping regulatory agencies understand a site and its emissions averaging program. Note that the rule also requires plan submission and, in some instances, plan approval should the Administrator or a delegated authority request one or both of those activities.

Comment 47: Commenter 17736 states that the emissions averaging provisions do not provide operational flexibility due to the short 30-day compliance period.

Response to Comment 47: As mentioned elsewhere, the agency and other commenters believe the rule's emissions averaging provisions offer much flexibility. Moreover, as discussed in the preamble, the rule now allows EGUs designed for coal ≥ 8,300 Btu/lb subcategory that are included in an emissions averaging group for Hg emissions a 90-boiler operating day rolling average period. Should an EGU owner or operator disagree, he or she should choose another compliance demonstration method.

Comment 48: Commenter 17775 opposes the requirement for the source to document the type, design, and operating specifications of the control devices installed on the effective date of the rule if performance test results are not available.

Response to Comment 48: The agency reviewed the commenter's suggestion, and, apart from identifying the control technology from each EGU, the rule does not require other information regarding the control devices.

Comment 49: Commenter 17821 states that section 63.10009(g)(2)(i) requests from all units in a potential averaging group, that sources identify the applicable emission level or control technology that is in place 60 days after the publication of the final rule. According to the commenter, that would require stack testing and other forms of monitoring, which a number of sources would not have performed by the date of the final rule. The commenter states that this suggests that some sources will have to replace existing control technologies with different technologies.

Response to Comment 49: The agency reviewed the commenter's suggestion, and, as mentioned elsewhere, the rule now requires information, including applicable emissions level or control technology as well as emissions test results, to be available within 3 years after promulgation.

Comment 50: Commenter 17881 states that it is not clear about how to apply emission averaging for CEMS versus stack testing results; i.e, how to compare a 30-day average from a CEMS to monthly stack test results.

Response to Comment 50: The agency agrees with the commenter, and the rule now describes how 30-day average CEMS values will be used with quarterly stack testing data to demonstrate compliance.

Comment 51: Commenter 17821 states that it is the EPA's intention to prevent units from using a lower, less restrictive emissions value in an averaging program based on the initial performance test than a unit was able to achieve when the final rule becomes effective. According to the commenter, from a practical point, this provision is flawed and unenforceable for two reasons:

a. The EPA has specified no practical way to determine what level of HAP emissions each unit is achieving on the date of the final rule without having a battery of performance tests on each affected unit and/or a program of extensive monitoring.

b. Many units will be undergoing control retrofits, such as the installation of FGD systems, sorbent injection, ACI, and fabric filters that will change the configuration of a unit. Some projects on their own could cause an increase in a unit's emissions, such as the potential for additional particulate related to ACI.

Response to Comment 51: As mentioned elsewhere, the rule now requires information from emissions testing be received and available for use in emissions averaging calculations on or before 3 years after promulgation. As the emissions averaging compliance approach may require additional testing or retrofits, an EGU owner or operator will need to include such factors in deciding whether or not to use emissions averaging as a means of demonstrating compliance.

Comment 52: Commenter 17881 states that the EGUs located at a single stationary source may not always have identical owners and/or operators contrary to section 63.10009(a). The commenter states that the language at 63.10009(a) would not preclude emission averaging amongst units under partial owners and/or operators, but perhaps the EPA should clarify this concept in the final rule preamble so as to eliminate any possible confusion in the future.

Response to Comment 52: The rule remains unchanged; EGUs under common control that otherwise meet the eligibility criteria, as described elsewhere, could be included in an emissions averaging group.

Comment 53: Commenter 17881 states that it is not clear if these provisions apply to each individual unit included in the averaging plan or all units in aggregate and notes that if multiple pollutants are being averaged, it is possible that new control devices targeting a given pollutant (i.e., acid gases) could result in a decrease in the control efficiency of another pollutant (i.e., PM or metals) and that control of a specific HAP could necessitate a reduction in the control efficiency for a different HAP.

Response to Comment 53: The agency believes EGU owners or operators are in the best position to weigh considerations mentioned by the commenter when deciding which compliance option to use. No change has been made to rule language regarding this comment.

Comment 54: Commenter 17881 states that the calculations at 63.10009(e)(1) and (2) should be dropped in their entirety as there is a major flaw in the initial qualification calculations, specifically, equations 1 and 2 require that the maximum rated hourly heat input (i.e., MMBtu/hr) or steam output (i.e., pounds) for each unit is to be used in the calculations. The commenter states that as long as the HAP emission rate for at least one of the EGUs to be included in the averaging plan is less than the applicable HAP limit, it is theoretically possible for the average HAP emission rate for the group of units to be compliant, but that if the EPA persists in maintaining some form of these calculations, the heat input or steam output used in the calculations should represent the projected monthly or annual heat input which will be achieved under the averaging plan. According to the commenter, this would allow those EGUs which will rely on capacity factor as part of the averaging plan to account for such reduced utilization in the calculations.

Response to Comment 54: The agency disagrees with the commenter's concern, and the rule has not been changed. An EGU owner or operator will have at least 3 years to get initial emissions testing complete and should be able during that time to have each of the EGUs fully operable for the time necessary to conduct emissions testing. If an EGU is unavailable, an EGU owner or operator could exclude that unit from the emissions averaging group or choose another method of demonstrating compliance.

Comment 55: Commenter 17881 states that the term "heat capacity" is improper in context of section 63.10009(f)(1) and (2), as heat capacity generally refers to the amount of heat required to change a substance's temperature by a specified amount; the term "heat capacity" should be replaced with "heat input". The commenter states that for Equation 3, the term Hb is currently specified as "The average heat input for each calendar month of EGU, in units of MMBtu"; the units of MMBtu represent the total monthly heat input, not the average monthly heat input (which would generally be expressed as MMBtu/hr); and thus, the term "average" in the definition for Hb should be replaced with "total."

Response to Comment 55: The agency agrees with the commenter that the equations 1 and 2 should refer to heat input, while equation 3 should refer to total monthly heat input, and the rule has been revised with these clarifications.

Comment 56: Commenter 17881 states that in section 63.10009(e) and (f), the equations 1 through 5 must be revised or clarified. The commenter states that all emission rates are expressed in units of lb/MMBtu or lb/TBtu, which ignores the fact that compliance on a lb/MWh or lb/GWh basis is also an option per Table 2 of the proposed rule. According to the commenter, if the EPA intends to allow the use of emission averaging to demonstrate compliance with pound per unit of electrical output limits, it may be appropriate to include additional equations which use electrical output as opposed to heat input or steam output for weighting purposes.

Response to Comment 56: The agency agrees with the commenter that an emissions rate based on electrical output, as well as on heat input, is appropriate for emissions averaging, and the rule has been revised to include rates based on electrical output.

Comment 57: Commenter 17881 states that the paragraph (g)(2)(vii) is confusing, which states that the averaging plan must include a demonstration that compliance with each of the applicable emission limits will be achieved. Commenter is confused about what emission rates should be used to make this demonstration.

Response to Comment 57: The rule's emissions averaging plan is intended to describe how each EGU emissions averaging group meets its emissions limit. One way of accomplishing this is to provide the results of each emissions test, along with requisite heat input information and the equations and results of the equations, in the emissions averaging plan.

Comment 58: Commenter 17881 states that section 63.10009(h) does not include SO_2 in the list of those pollutants which may be averaged for common stacks. The commenter states that if this is just an error, then the EPA should correct prior to rule finalization.

Response to Comment 58: As mentioned earlier, the rule has been revised to include SO_2 in the list of those pollutants which could be used in emissions averaging.

Comment 59: Commenter 17881 states that the section 63.10009(i) stipulates that individual units sharing a common stack must vent through a common emissions control system. Commenter recommends that if EGUs associated with the common stack are all affected units within the same category, compliance should be allowed at the common stack based upon treating such averaging group as a single stack.

Comment 60: Commenter 17881 states that equation 6 of 63.10009(j)(1) is supposed to be used to determine the common stack emission limit in cases where it is shared by EGUs in different subcategories. According to the commenter, the current equation is lacking in several regards, and in cases where the common stack emission levels can comply with the most stringent of the applicable emission limits, this would negate the need to calculate custom common stack emission limits based upon prorating the emission limits for applicable subcategories.

Response to Comments 59 - 60: The agency agrees with the commenter's first suggestion, and the rule has been revised to treat emissions from a common stack used by only EGUs eligible for emissions averaging as a single unit. The agency disagrees with the commenter's second assertion, and the rule has not been changed. Existing EGUs from the same subcategory can share a common stack and be included in emissions averaging provided that EGUs not in the emissions averaging group (perhaps because they are new or they belong to a different subcategory) can be turned off during emissions testing of the units within the emissions averaging group or that every EGU meets the most stringent emissions limit applicable to any EGU. Should an EGU owner or operator find these eligibility criteria burdensome, he or she should choose another compliance demonstration option.

Comment 61: Commenter 17881 requests that the heat input/steam output records as required by section 63.10032(e) should be kept on a monthly instead of daily basis, as all related calculations in 63.10009 are on a monthly rather than daily basis.

Response to Comment 61: The agency disagrees with the commenter's suggestion because the rule contains a 30 boiler operating day rolling average, meaning that heat input is required on a daily, not monthly, basis.

Comment 62: Commenter 17913 states that the emissions averaging demonstration should only be based on an averaging period consistent with the given emission standard. According to the commenter, for example, if emissions averaging is used to demonstrate compliance with a 30-day emission standard, then the compliance demonstration should only be based on each 30-day compliance period. There is no need or benefit to requiring instantaneous compliance with the standard during an initial performance test, as currently required by the proposed regulation. The commenter states that the requirement to demonstrate instantaneous compliance with a 30-day limit through emissions averaging using performance test data eliminates much of the benefits of allowing for an emissions averaging approach and doesn't provide benefits for facilities that wish to limit use of less-controlled units.

Response to Comment 62: The agency agrees with the commenter's suggestion to clarify how compliance is demonstrated. As rule contains a quarterly compliance assessment based on results of quarterly emissions tests for EGUs that use emissions testing and of 30 (or 90, as discussed elsewhere) boiler operating day rolling averages for EGUs that use CEMS (or sorbent trap monitoring for Hg emissions), the rule has been revised to stress compliance with the 30 (or 90, as discussed elsewhere) boiler operating day rolling averages for those EGUs that rely on CEMS (or sorbent trap monitoring systems for Hg emissions). Note that this means the quarterly emissions testing value is used during the quarter to assess compliance with emissions limits. Should an EGU owner or operator find such an approach problematic, he or she should choose another compliance demonstration option.

Comment 63: Commenter 19120 requests revision of the rule to allow for PM CEMS emissions data to be used in emissions averaging to show compliance with metal HAP emissions. The commenter states that this request could be completed through a site-specific alternative monitoring request per 40 CFR 63.8(f), but due to the potentially large number of facilities requesting a site specific approval to use alternative monitoring and emissions averaging plans, the EPA should include this option directly in the final rule. The commenter states that because approval from the EPA is required before a source may use the alternative monitoring procedure, this could hinder the ability for sources to plan in advance and be proactive with installation of compliance monitoring equipment.

Response to Comment 63: As mentioned elsewhere, the rule now allows EGUs that use CEMS, including PM CEMS, to be eligible for emissions averaging. Note that data from a PM CEMS would be used to show compliance with the filterable PM, not non-Hg HAP metals, emissions limit.

5. Opposition to discount factor.

Comment 64: Numerous commenters (17714, 17718, 17402, 17623, 17689, 17705, 17716, 17725, 17730, 17731, 17737, 17774, 17775, 17816, 17820, 17821, 17885, 17904, 18014,18025, 18449, 18498, 18023) disagree with use of a discount factor. According to the commenters, imposition of a discount factor effectively lowers the allowable emissions for those sources without any justification. The commenters note that the EPA has used discount factors in other NESHAP where the agency believed there was variation in the types of units engaged in averaging. The commenters states that the EGUs covered by this rule are fairly homogeneous, and the current proposal does not allow averaging between units of different subcategories. Commenter 17904 states that a discount factor will simply act as a deterrent to emissions averaging.

Comment 65: Commenters 17402 and 17716 notes the discount factor increases the stringency of the emissions standards (amounts to an “above the floor” standard) for sources participating in emissions averaging. Commenter 18023 stated that tightening the standards by any percentage for sources that emissions average makes an impossible compliance situation even worse. Commenter 17402 notes that the discount factor is not being applied in the Utility MACT to account for variation in types of units, as was the case where discount factors have been applied for other NESHAP. Commenters 17402 and 17623 agree with the EPA that the “homogeneous” nature of the sources eligible for the Utility MACT averaging provision makes a discount factor unnecessary. Commenters 17402 and 17623 agree that requirements to monitor and demonstrate compliance assure environmental benefits are achieved and also make the discount factor not appropriate. Commenter 17705 concurs that emissions averaging for EGUs that are co-located at a single facility should be straight-forward. Commenter 17705 indicates that the NESHAP numeric limits and the additional requirements for control device operating parameters and fuel limits already reduce the usefulness of emissions averaging as a compliance option, and if the EPA further adds a discount factor, the commenter suspects emission averaging will not be a viable compliance alternative for any sources.

Comment 66: Commenter 17648 states that using a discount factor would be more consistent with the HON Rule. Commenter 17648 notes that the HON Rule was clear that the cost savings for sources choosing emissions averaging should be considered in determining the appropriateness of a discount factor. 59 FR 19430. The commenter states that more recently, the EPA relied upon its reasoning in the HON Rule to apply the 10 percent discount in the emissions averaging provisions for ICI Boilers (see 76 FR 15619; 75 FR 32035), and that its decisions in the HON and ICI Boiler NESHAP were well founded and necessary to assure that sources opting to use emissions averaging were emitting at levels no less stringent than would be required under a unit-by-unit MACT standard. The commenter states that the EPA offers no rational basis for failing to adopt the same approach in this rule.

Comment 67: Commenter 17714 states that allowing averaging without discounting would provide a positive incentive to encourage companies to upgrade or install controls that would achieve reductions beyond compliance requirements and allow the utilities to achieve more cost-effective reductions overall by investing resources where the greatest reductions can be made.

Comment 68: Commenter 17768 states that applying a discount factor would essentially penalize averaging and disincentivize sources from using this option and that is also possible that averaging may lead to fewer reductions in emissions and thus fewer benefits to the general public.

Comment 69: Commenter 17928 states that averaging provides valuable flexibility but is already constrained by the differing schedules of plant outages at the same facility, as well as emissions variability. The commenter states that a ten percent penalty further limits the utility of this option.

Response to Comments 64-69: The agency reviewed the commenter’s concerns and suggestions, but decided not to change the rule by including a discount factor for those EGU owners or operators who choose to use emissions averaging. The agency agrees with many of the commenters who pointed out EGU homogeneity as being a reason why emissions averaging without a discount factor is well-suited for this rule. Requirements for units subject to the HON rule, which covers a broad number of unit types, products, and processes need not be forced upon EGUs which differ generally only in the fuel used to produce electricity. The agency believes that difference is accounted for in this rule by prohibiting units from differing subcategories – which are fuel based – from participating in emissions averaging. The agency believes the EGU owner or operator flexibility coupled with the lower cost advantage of emissions averaging makes such a program a viable choice, particularly for little used or soon-to-be retired EGUs. Should an EGU owner or operator disagree, he or she should choose from among the other compliance demonstration options.

6. Support of discount factor.

Comment 70: Commenter 17648 supports the four criteria required by the EPA to participate in emissions averaging and states that the EPA should go further and also apply a discount factor, as it has done in prior NESHAP. Commenter 17648 states the proposed emissions averaging provisions do not sufficiently recognize and compensate for the fact that averaging may not assure that all units are being controlled aggregately to a degree no less stringent than they would need to be controlled if they were controlled individually. In failing to incorporate a discount factor, Commenter 17648 states the EPA may unfairly advantage multiple-unit sources over single-unit EGUs. Commenter 17648 notes that having accounted for variability in setting emission limitations by calculating MACT floors based upon the 99% UPL, the EPA has provided sources with ample protection from anomalous outcomes. According to the commenter, the 99% confidence level was established to account for variability, measuring the variability of single-unit, single measurements from the average, but under the EPA's averaging provision, a multiple-unit facility will reduce variability by averaging both between units and over time. According to the commenter, the 99^{th} UPL for facilities that average would be closer to the actual average of the top 12% than the 99^{th} UPL for an individual measurement at an individual facility, and thus, sources with multiple units eligible for averaging may be able to take advantage of averaging to avoid installing or operating controls that would be required for individual sources. The commenter states that incorporating a discount factor is important to maintain a level playing field, to ensure that sources will in fact install controls that reduce emissions while providing flexibility to do so in the most cost-effective manner possible and that it is also the only way to ensure that the limit actually equals the average attained by the average of the best performing 12% of the sources within the subcategory.

Comment 71: Commenter 17648 disagrees with the EPAs suggestion that homogeneity of sources makes a discount factor unnecessary, and notes that the substantial subcategorization into 11 different subcategories in the ICI Boiler NESHAP undercuts the EPA's rationale for not proposing a discount factor in the Toxics Rule. In the ICI Boiler NESHAP, commenter 17648 states that the subcategorization reduced variation among sources within the subcategory, and that NESHAP nonetheless retained a discount factor. 76 FR 15612. Commenter 17648 states that the EPA's rationale also fails to account for the mathematical/statistical basis for requiring a lower limitation when averaging is allowed. According to the commenter, by basing the initial limit on the 99% UPL rather than the more conventional 95 percent UPL in both rules, the EPA has already accounted for any greater variability within the pertinent subcategories. Commenter 17648 states that if there is less variability within the EGU subcategories, this would only suggest that the EPA should employ a somewhat smaller discount, and would not support eliminating the discount altogether.

Comment 72: Commenter 17648 supports the emissions cap for any individual regulated unit operating above the emissions limitations that would apply to that unit at the level achieved 30 days after promulgation of the Toxics Rule, however, this cap alone will not achieve sufficient assurance that emissions averaging will be at least as stringent as the conventional MACT.

Comment 73: Commenters 17648 and 17789 state that prior NESHAP have relied on additional safeguards such as the cap only as a supplement to the 10 percent discount and urge the EPA to continue to use the criteria to limit averaging.

Comment 74: Commenter 17718 states that imposition of a discount factor effectively lowers the allowable emissions. According to the commenter, a discount factor is unnecessary because the proposed rule incorporates a number of other safety factors that obviate the need for a discount factor.

Comment 75: Several commenters (19536, 19537, 19538) states that the EPA should add a discount factor requiring lower emissions from plants which comply by averaging the emissions of multiple units. According to the commenter, the agency's variability analysis is based on emissions from three test runs from a single boiler, operating over a 2 (Hg and PM) or 3 (acid gases) hour period, and by allowing averaging, the EPA is effectively allowing compliance to be measured based upon a far larger number of test runs, and operating hours – over which there will be far less variability and thereby allows sources to emit hazardous pollution well in excess of the actual emissions of the best performing similar plant or plants. The commenter states that the EPA should, as a general matter, establish standards that are consistent in their form with those the agency uses when it assesses variability; its standards will not otherwise reflect the performance of the best source or sources. According to the commenter, in this instance, if the EPA allows units to combine their emissions for purposes of compliance, it should re-calculate the variability associated with multiple-unit emissions, and establish a corresponding "discount" in the standards for multiple units.

Response to Comments 70-75: The agency considered the commenters' suggestions but did not change the rule to include use of a discount factor. As mentioned elsewhere, the agency agrees with the suggestion that other safety factors in the rule obviate the need for a discount factor. The agency notes that while emissions averaging could begin upon promulgation of the rule, it must start within 3 years of promulgation. Finally, the agency disagrees with the suggestion that another variability component need be considered for those EGU owners or operators who choose to engage in emissions averaging; the current UPL analyses was developed to take factors such as those mentioned by the commenter into account.

7. Facility averaging provisions should be modified to allow for alternative mass limits.

Comment 76: Commenter 17877 supports the idea of facility emission averaging, in as much as it may provide real operational flexibility to sources. According to the commenter, however, the averaging provisions of the proposed rule are so restrictive that they are unlikely to be used, and the 10 percent "discount factor" of which the EPA is seeking comment will certainly deter averaging since artificially lowering the standards will render the already complicated task of compliance even more difficult. The commenter states that there is no legitimate reason for imposing a 10 percent penalty on sources that seek to average emissions.

The commenter states that total emissions from a single facility have the same impact on public health regardless of whether each unit at the facility meets the MACT limits or all units meet the MACT limits in the aggregate -- the total emissions from the facility are the same, and the 10 percent penalty on operational flexibility has no public health benefit.

Comment 77: Commenter 18788 finds that in practice the draft model for source averaging would penalize a facility when the best performing units are not operating. The commenter states that at a facility where eligible units are combined under a weighted average emission rate, the emission rate average of the operating units will calculate higher when the best performing unit(s) are shut down and emitting no HAP what-so-ever, and that this effect is especially pronounced when the best performing unit is the largest among the group.

The commenter presented Example 1 below of a hypothetical facility, with all units online and in compliance with the total particulate limit of 0.03 lb/MMBtu on a facility basis.

Example 1: All Units Online

In the second example, the newest and best performing unit is offline and mass emissions from the facility are decreased by as much as 30% as compared to Example 1, but the facility is now out of compliance with the total PM limit on a weighted average basis. According to the commenter, the facility is therefore penalized for emitting less.

Example 2: Unit 3 Offline

Commenter 17877 suggests that EPA could address the averaging penalty in one of two ways: First, the EPA could allow for the facility total heat input to be fixed at all times in the denominator of the averaging equation for each unit. According to the commenter, for the hypothetical facility, the hourly averaging calculation would be as so:

(Unit 1 Emission Rate * Actual Heat Input / 12,000)

(Unit 2 Emission Rate * Actual Heat Input / 12,000)

+ (Unit 3 Emission Rate * Actual Heat Input / 12,000)

Facility Average Emission Rate

The commenter states that according to this method, the facility is actually encouraged not to operate units and emit less, and enforceability is strengthened and facility compliance is simplified since the MACT limit can be clearly and consistently compared to the Facility Average Emission Rate at all times. According to the commenter, as currently drafted, the facility average method is of little use and creates a constant moving target for the agency and the regulated facility.

The commenter states that as an alternative, or in addition to the above, the rule could be written to include an alternate mass emission limit for the facility. According to the commenter, in this case, the annual mass emissions would be based on the allowed emission rate multiplied by the hourly heat input of the unit over the course of a year (included in document).

The commenter states that both of the proposed changes to the facility averaging provisions listed above fit squarely within the generally applied limits on the “scope and nature” of past rulemakings where facility averaging is allowed. The commenter asserts that if the EPA is serious about providing operational flexibility to facilities, then it must make substantial revisions to the averaging provisions of the rule.

Response to Comments 76 and 77: : While the agency appreciates support for use of emissions averaging without a discount factor, as mentioned elsewhere, the agency disagrees with the commenter’s views on the suitability of mass emissions for emissions averaging in this rule. The agency believes it would be inappropriate to introduce a new emissions limit based on mass only without appropriate notice and comment on that suggestion. The rule's emissions limits remain unchanged. Should an EGU owner or operator find the rule's existing emissions averaging procedures too stringent, he or she should choose from the other compliance determination options.

5C03 - Compliance: Fuel switching

Commenters: 16705, 17400, 17697, 17725, 17737, 17756, 17774, 17810, 17813, 17820, 17840, 17852, 17853, 17881, 17901, 17902, 17904, 17912, 17930, 18038, 18421, 18428, 18477, 18502, 18575, 19536, 19537, 19538, 18023

1. Coal switching.

Comment 1: Several commenters (16705, 17400, 17697, 18038, 18575) point out that the proposed rules assume that all coal types can still be used with available control technologies, but this may not be the case. Such fuel switching from one coal type to another or fuel blending can be very expensive for a municipal utility. Commenter 17697 adds that Guam is very restricted in fuel choices, and the GPA must rely on oil for the near to midterm.

Comment 2: Commenter 18023 states that while decisions will be made to change the fuel supply for some coal-fired units to natural gas-fired units based on the economics of available alternatives, it is important to note that any decisions to change the fuel for an existing coal unit to natural gas or oil would never be economic when compared to business as usual and would only occur because of the requirements imposed by the proposed rules. Commenter states that changing fuel to natural gas also presents important reliability considerations, including the capability for back-up fuel, such as oil, in case of supply disruptions because natural gas cannot be stored on-site.

Comment 3: Commenter 17881 states that rail congestion and increasing transportation cost limit the viability of the PBR coals option. Commenter adds that the chlorine content in western coal can vary widely, making DSI a non-viable option for every unit.

Comment 4: Commenter 18421 cites the URS report which points out that coal switching is potentially an option for compliance for some coal units burning lignite. Commenter adds that plants burning Texas lignite will need to remove mercury at high levels to comply, and switching to western subbituminous coal could significantly decrease mercury emissions due to Hg content of coal and improved ACI performance.

Response to Comments 1 - 4: The EPA has not mandated fuel switching as a compliance option – nor has the EPA used fuel switching to set emission floors or as a 'beyond-the-floor' option. The EPA does, however, recognize that fuel switching is a legitimate compliance option that will be considered and likely implemented by some facilities. Low sulfur sub-bituminous is now widely available and is burned across the contiguous U.S. states to comply with SO_2 limits. The EPA is aware of facilities in the East (e.g., Florida, Georgia, Maryland, Connecticut, and Delaware) and in the West (e.g., Oregon, Washington, and Arizona) that are firing or co-firing sub-bituminous coal. The EPA maintains that control technology options are available to retrofit existing facilities to allow them to meet the existing source emission limits without having to switch fuels.

2. Opposition to fuel switching to natural gas.

Comment 5: Commenter 17881 states that natural gas transmission and storage infrastructure does not exist to support the option of fuel switching to natural gas and adds that it cannot be put in place within the constraints of a MACT time-line.

Comment 6: Commenter 17881 states that exclusive use of natural gas at Consumers Energy's Karn's Oil/Gas Fired Units – 3 & 4 (currently rated at 638 MW each, but less than 5 percent capacity factor) would require these units to be de-rated 50 percent to about 300 MW each or have significant boiler modifications to allow the firing of 100 percent natural gas at the boiler design capacity. According to the commenter, the natural gas supply infrastructure would have to be significantly upgraded in order to supply the volume of gas needed to operate the units at full capacity. The commenter states that these units are called on only when electric load demand is high, as in the summer of 2011, and perform a vital role to meet load demand.

Comment 7: Commenter 17901 states that natural gas units are not covered under the proposed Utility MACT, and the EPA has given no indication that it will establish any stringent limits for natural gas units comparable to those required from coal-fired units. Commenter states that the proposed MACT is a continuation of an ongoing pattern of disparate treatment for coal utilities. Commenter disagrees with the EPA's consideration of requiring fuel switching from coal to gas as a potential "beyond-the-floor" control, although the EPA properly rejected the use of natural gas as a control option. Commenter disagrees with consideration of fuel switching to an entirely different fuel with totally different delivery systems, types of combustion, and emissions control systems to be a feasible option at all. Commenter supported this point by citing the EPA's statement that, "natural gas pipelines are not available in all regions of the U.S., and natural gas may not be available as a fuel for many EGUs." Commenter also states that the EPA notes that the relative cost of a switch to natural gas from coal was many times higher than the cost to install additional control equipment on coal plants.

Comment 8: Commenter 17912 states that switching from coal or oil to natural gas is not appropriate as a control option and not feasible for many units and concurs with the EPA's proposal not to require fuel switching as a "beyond-the-floor" option for the EGU MACT. Commenter agrees with the EPA reasons for not requiring fuel switching to natural gas, which is delivered through pipelines, is not available everywhere in the U.S., where pipelines do exist, natural gas may not be available throughout the year (e.g., the heating season), and the cost of such fuel switching would be prohibitive in many circumstances. Commenter urges the EPA not to modify or reconsider this proposal not to use natural gas as a "beyond-the-floor" option.

Response to Comments 5 - 8: The EPA has not mandated fuel switching as a compliance option – nor has the EPA used the potential for fuel switching to set emission floors or as a "beyond-the-floor" standard. The EPA does, however, recognize that fuel switching is a legitimate compliance option that will be considered and likely implemented by some facilities. However, the EPA maintains that control technology options are available to retrofit existing facilities to allow them to meet the existing source emission limits without having to switch fuels.

3. Concerns with ability to meet liquid fuel-fired limits.

Comment 9: Commenter 17912 disagrees with the EPA's suggestion that oil-fired units have the compliance option of using low-HAP oil, citing that the EPA fails to identify anywhere in the ICR fuel data any oil sufficiently low in HAP that a liquid fuel-fired boiler has used this method to comply.

Comment 10: Commenter 18502 points out that compliance with the proposed metals and HCl limits by residual oil-fired EGUs assumes a level of consistency in flue gas composition that has not been demonstrated as compared to coal-fired units. According to the commenter, there are some key differences between coal and oil relative to compliance with the proposed emission limits:

a. The concentrations of metals and chlorine in coal can be measured, but are generally below analytical detection limits for residual oil. The commenter states that during ICR testing, quantifiable levels of chlorine were detected in the fuel used by just two of the eight EGUs tested and nickel was the only metal detected in more than a quarter of the samples.

b. Coal is supplied to an individual EGU from suppliers in defined geologic and geographic areas that have definable fuel characteristics, whereas deliveries of crude oil to refiners and fuel oil to consumers are based on international market conditions. The commenter states that while fuel specifications regarding some parameters are possible (e.g., sulfur content), use of fuel specification to control chlorine and metals content of oil is untested.

c. Air pollution control technologies to reduce criteria pollutant emissions from coal-fired boilers is well documented and can be used to estimate reductions in HCl and metals emissions; however, control technologies are less commonly used with oil-fired boilers, and the correlation between reductions in PM and reductions in metals is not as well defined.

Response to Comments 9 - 10: As noted elsewhere in this document, EPA has reassessed its analysis of the oil-fired EGU data. The EPA believes the limits in the final rule, which are based on emissions data from existing liquid oil-fired EGUs, are achievable by oil-fired EGUs. Further, EPA is providing for an alternate compliance assurance alternative for the acid gas HAP of measuring the moisture in the oil in lieu of testing for HCl and HF.

4. Opposition to conversion of liquid-fired EGUs from RFO to DFO.

Comment 11: Commenter 17725 points out several challenges to converting liquid-fired EGUs from residual fuel oil (RFO, oil grades No. 4, No. 5, and No. 6) to distillate fuel oil (DFO, oil grades No. 1 and No. 2), and states that these oils have distinct separate characteristics and they are not interchangeable:

a. According to the commenter, different ASTM Standard D396-10, Standard Specifications for Fuel Oil (Standards) include differing requirements (e.g., flash point, viscosity pour point) that affect different storage requirements. According to the commenter, many RFO storage facilities have heated storage tanks, an oil recirculation system, and heated conveyance piping to the boiler, and conversely, the storage of DFO does not require heated systems.

b. According to the commenter, combustion of RFO and DFO is not interchangeable within a boiler, and a fuel switch to DFO requires significant modification. According to the commenter, because of the different physical characteristics, the combustion process equipment is designed and installed to reflect the characteristics of the fuel being combusted. The commenter states that boiler burners and burner tips used to combust RFO cannot be used to combust DFO and that the converse is also true. The commenter states that once introduced to the boiler, proper combustion of RFO can only be obtained by using steam atomization or mechanical atomization, and conversely, combustion of DFO does not require an atomization system.

c. According to the commenter, an EGU using RFO will not have the same output (steam flow and the resulting generation) using the same amount of DFO because of the lower heating value of DFO. According to the commenter, the lower output of a DFO unit would be approximately 15 – 20 percent; for example, a rated 200 MW unit using RFO would only be a 160 – 170 MW unit using RFO.

d. According to the commenter, conversion to DFO would entail modifications to the boiler combustion system, as well as a conversion of the oil storage tank system, including replacement of burners and burner tips and modifications to the burner management system. The commenter states that prior to performing the physical changes, a boiler combustion study must be performed to ensure the burners are properly designed for the boiler's configuration.

e. According to the commenter, to prevent contamination from RFO, an existing RFO storage tank and the associated piping must be cleaned.

f. According to the commenter, change out of the piping and pumps are required so that the required amount of DFO (which has a lower heating value) can be delivered to the boiler to maintain full load capability.

g. According to the commenter, a spill or leak of DFO will tend to flow further and faster than a spill or leak of RFO, due to the lower viscosity.

h. According to the commenter, many existing storage tank systems would need retrofitting to provide adequate secondary containment for the lower viscosity DFO to address regulatory requirements for fuel storage (i.e., SPCC, OPA-90). According to the commenter, this is a significant undertaking for large RFO tanks, as they typically use earthen secondary containments, since RFO does not permeate into the soil when spilled; whereas, converting to DFO storage would require expensive impermeable liner installation and other changes. Commenter 17725 cites an example cost estimate for liner installation for a relatively small two million gallon tank being from $500,000 to $800,000 and adds that their Oswego facility has multiple 11 million gallon tanks, the cost of which to line one of these tanks would be on the order of two to three million dollars.

i. According to the commenter, the capital investment for a conversion to DFO is site specific but, NRG estimates that the conversion cost for their facilities ranges from $12 – 17/installed kW per site, and this is only for the capital expense portion.

j. According to the commenter, there are additional costs for testing the unit to ensure that the conversion will allow the EGU to meet the emission rate (prior to the actual compliance stack test). The commenter states that the tuning and testing will require EGU full load operations for approximately 40 hours. A 400 MW unit can consume approximately 500 gallons per minute of fuel, and that for the 40 hours of tuning/testing, this relates to 1.2 million gallons of fuel, or approximately 29,000 barrels of fuel. The commenter states that additional fuel use is required for the start-up and ramp up to full load and shut down of the unit. The commenter states that the additional cost for the 29,000 barrels of DFO is over $500,000, based on the 5-year average price presented (Commenter included Table 2.3.2, Five-Year Average Fuel Prices at New York Harbor, Docket No. The EPA-HQ-OAR-2009-0234).

k. The commenter states that beyond the capital expenditures to retrofit units for DFO, the use of DFO rather than RFO will increase the dispatch price of the EGU. According to the commenter, for an EGU with a 10,000 Btu/kW-hr heat rate, the dispatch price for the unit based on fuel alone will increase between 35 and 45 percent. The commenter states that as oil-fired EGUs are generally high on the supply curve due to their relatively high heat rates, they are primarily dispatched for reliability at a low level in preparation for spikes in demand (when their output will be increased), to cover for known outages of lower cost units, or to provide transmission support. The commenter states that conversion to DFO will increase their production costs up to 45% or more and put significant upward pressure on electric costs during times of system duress.

l. According to the commenter, conversion to DFO presents compliance risks for EGUs, as compliance is based on the assumption that the source's emissions will be in the same range as those DFO-fired units setting the standard. The commenter states that it is highly doubtful that an engineering and construction firm would provide a guarantee that a conversion to DFO would in fact meet the proposed total metal limits. According to the commenter, the rule does not provide an exemption or waiver for an EGU that has been converted to a lower emitting liquid fuel and still cannot meet the total metal limit. The commenter states that faced with the possibility of making a significant capital investment with no assurance of ultimately achieving compliance, the EGU may be forced to retire as the uncertainty is too great. The commenter states that EGUs that may or could comply would simply not make an investment that large without reasonable assurance of being able to comply rendering unintended outcomes of the rule's primary objective.

Response to Comment 11: The EPA acknowledges that capital expenditure may be needed to be able to convert from residual oil to distillate oil. However, we would also note that other commenters indicate that the switch is not as extreme or burdensome as commenters here note. Further, we are not subcategorizing distillate vs. residual oil in the final rule. We note that all of the distillate oil-fired EGUs for which we have data are in the limited-use subcategory noted elsewhere in this document. The MACT floor pool for liquid-oil fired EGUS is comprised of sources burning residual oil-fired EGUs with ESPs. Therefore, EPA maintains the final limits are achievable by residual oil-fired EGUs without the need for oil switching, although such switching is always an option to an EGU that does not want to install PM controls.

5. Opposition to use of proposed rule/limits to necessitate fuel switching.

Comment 12: Commenters 17813 and 17930 discourage the setting of limits that are so low as to possibly necessitate fuel switching, stating that this would be a requirement found nowhere in the CAA, is contrary to decades of precedent, and would set a dangerous policy that would undermine regional electric reliability and affordability. Commenters add that lignite-burning power plants are mine-mouth power plants wedded to their mines, and a switch to subbituminous coal to meet proposed emission limits would mean sacrificing significant financial investments in fuel delivery, transportation, and storage, not to mention boiler design. According to the commenters, boilers are designed for specific types of fuel, as well as ranks within a fuel type, and there are limits due to the heat values and amount of coal being burned that restrict lignite power-plants from increasing non-lignite coal consumption. The commenters state that these issues were obviously considered and given weight when the EPA developed the subcategory for <8,300 Btu/lb coal.

Comment 13: Commenter 17840 states that the EPA should articulate how a future plant can comply with all of the proposed standards, and draws a conclusion that the EPA is proposing a beyond-the-floor fuel switching measure for new sources, while inconsistently rebutting mandating fuel switching from coal to natural gas as "an unreasonable regulatory option."

Comment 14: Commenter 17930 states opposition to requirements that impose fuel switching and notes that fuel switching is not a viable option for many lignite units in Texas. Commenter states that for many, the necessary infrastructure (e.g., rail lines, unloading stations, transport areas) does not exist to begin burning other types of coal. Commenter states that the EPA's cost estimates for facilities to switch to other coal types and construct this infrastructure is incomplete and provides the following points as flaws in the EPA cost analysis:

a. According to the commenter, the EPA's cost estimate does not include all requisite infrastructure costs (e.g., dust collection, conveyors, fire protection, ventilation, ESP performance, water cannons, significant boilers modifications to burn 100 percent PRB coal.

b. According to the commenter, the EPA has not adequately taken into consideration the potential escalation of PRB coal and transportation prices once the coal fleet responds to this and other pending regulations (e.g., the Cross-State Air Pollution Rule [CSAPR]).

c. According to the commenter, the EPA's cost prediction for the "beyond-the-floor" limit is far too low because the EPA fails to include the cost of installing fabric filters in the price analysis. The commenter states that the EPA's cost analysis assumes that all units within this subcategory will require capital investments in fabric filters that are attributable to the proposed MACT standard for PM (as a surrogate for non-Hg metallic HAP). According to the commenter, this analysis determines the marginal capital costs attributable to the BTF option requiring installation of ACI systems to reduce Hg emissions to 4.0 lb per trillion Btu (Commenter cites a Beyond the Floor Letter, Shelley Johnson to Bill Maxwell, included in Docket No. The EPA-HQ-OAR-2009-0234). Commenter points out that this assumption is flawed for two reasons:

1. Fabric filters will not necessarily be installed at these units. According to the commenter, while surrogates may be a means of compliance for lignite-fired EGUs, the rule still allows for the control of the non-Hg metallic HAP themselves, which may not require a fabric filter.

2. The EPA cannot exclude the costs of a control technology installed to control Pollutant A (which incidentally controls for Pollutant B), while counting the benefits of the limitation on Pollutant B. The commenter states that benefits cannot be counted twice, while costs only counted once.

Response to Comments 12 - 14: The EPA has not mandated fuel switching as a compliance option – nor has the EPA used fuel switching to set emission floors or as a 'beyond-the-floor' option. The EPA does, however, recognize that fuel switching is a legitimate compliance option that will be considered and likely implemented by some facilities. Low sulfur sub-bituminous is now widely available and is burned across the contiguous U.S. states for compliance with existing SO2 standards. The EPA is aware of facilities in the East (e.g., Florida, Georgia, Maryland, Connecticut, and Delaware) and in the West (e.g., Oregon, Washington, and Arizona) that are firing or co-firing sub-bituminous coal. Control technology options are available to retrofit existing facilities to allow them to meet the existing source emission limits without having to switch fuels. We maintain that the final limits were established in accordance with the statute and have considered costs to the extent required.

6. Request for expansion of provisions for exclusion from requirements.

Comment 15: Commenter 17737 agrees with the provision to exclude units that did not fire coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years from subpart UUUUU. However, Commenter recommends that this be expanded to include units that have burned coal for more than 10.0 percent during the 3 years immediately following promulgation of the final rule, or 15 percent during any one of those years, but elect to switch to burning natural gas for at least 90 percent of the annual heat input beginning prior to the date the units must be in compliance. Commenter adds that this provision should not require the unit(s) to be modified by making the coal burning capabilities inoperable or needing to modify the permit to remove the coal burning capabilities and cites that the proposed definition of "fossil-fuel fired" unit (76 FR 25020) seems to require that the owner physically remove all coal burning capabilities and that coal burning would not be allowed in the permit. Commenter states that they (TEP) own and operate H. Wilson Sundt (Sundt) Unit 4, which is capable of burning coal and/or natural gas, and TEP would like to have the option to use this flexibility to bum different types of fuel. TEP would like to maintain the ability to continue to bum coal in this unit for the next 3 years but switch to natural gas prior to the date the unit would need to be in compliance with subpart UUUUU. According to the commenter, under the present proposed rule, TEP would still be subject to the subpart UUUUU monitoring, reporting, and recordkeeping requirements even if it ceases to burn coal prior to the compliance date, posing an unnecessary regulatory burden without environmental benefit. Commenter suggests that if a unit is capable of burning different types of fuel, including coal, then the owner/operator should be required to maintain records of the quantity and type of fuel burned to assure that at least 90 percent or more of the heat input is from natural gas and that the operating permit would be revised to require the owner/operator to apply for a permit revision to comply with the requirements of subpart UUUUU prior to resuming to burn coal in quantities ≥ 10 percent of heat input.

Comment 16: Commenter 17756 cites that in order to convert a unit to natural gas or biomass and be exempt from the proposed Toxics Rule, the owner would need to convert the unit to 100 percent biomass or natural gas within three years and remove all capability to burn coal or oil. Commenter suggests that alternatively, the unit could convert to biomass or natural gas by 2012 and ensure that the heat input from coal or oil in 2012, 2013, and 2014 is below the annual 15 percent heat input requirement and the 3-year requirement of 10 percent heat input.

Comment 17: Commenter 17756 recommends that the EPA revise the definition to change the "look-back" period to begin three years after the unit's final compliance date. According to the commenter, this change would not penalize a unit that switches to natural gas and retains the ability to combust coal or oil for having burned coal or oil in the period before compliance. Commenter also suggests that a unit that switches to natural gas and later switches back to highly controlled coal use should not be in violation of the 3-year average for the years it was burning natural gas.

Comment 18: Commenter 17820 recommends that the EPA change the "look-back" period under the applicability criteria for units that cease combustion of coal or oil to provide absolute assurance that units converted to natural gas or biomass are exempt from the rule.

Comment 19: Commenter 17902 recommends that section 63.9981 further clarify that existing coal or oil-fired EGUs that combust natural gas as of the required compliance date are not subject to the requirements of subpart UUUUU.

Comment 20: Commenter 17904 recommends that the EPA should revise the applicability language to allow generators to retain the option of simply restricting dual fuel-fired units as a compliance strategy – but they should not be forced to begin fuel restrictions immediately. According to the commenter, this would amount to making the compliance date equivalent to the effective date of the rule. Commenter recommends that the EPA should revise the definition to clarify that any unit which actually burns 90 percent natural gas during a calendar year is excluded from compliance obligations, irrespective of whether the unit fired some large percent of fossil fuel prior to the effective date.

Comment 21: Commenter 18428 supports the provision in the EGU MACT that a unit that burns on average at least 90 percent of fuel as natural gas during, "the previous 3-year period," is considered natural gas-fired and therefore not subject to the EGU MACT. However, the commenter requests that the EPA add to this provision that units that switch to natural gas by the compliance deadline and continue to operate that way thereafter should also not be subject to the oil-fired EGU MACT requirements.

Response to Comments 15 - 21: As noted elsewhere in this document, the EPA has revised the definitions to account for the "look back" provision noted by commenters.

7. One-year extension for compliance.

Comment 22: Commenter 17852 concurs that a 1-year extension can be appropriate when a utility is undertaking a technically complex project, such as converting an existing coal-fired boiler to burn natural gas or building a new NGCC, but only where the utility has timely gone about such action and can demonstrate that such action does in fact require an extra year to comply. Commenter adds that there are many things that utilities can do to achieve compliance within the 3-year time-frame, and cites the following:

a. Various sources have suggested that controls can be installed within the 3-year time-frame, including, Exelon Corporation which has said in reference to the Boiler MACT, "We know we can install controls in three years because many plants have already done it in that timeframe."

b. Existing, high-efficiency NGCC units are underutilized and can immediately increase generation, allowing for older, uncontrolled coal plants to be retired, without an extension of the MACT regulatory time-frame.

c. Various sources have shown that new natural gas generation can be built within the mandated 3-4 year time-frame.

Response to Comment 22: Responses to comments of this type are provided in the preamble to the final rule.

8. Blending fuels.

Comment 23: Commenter 17774 points out that the proposed Utility MACT definitions of various regulated subcategories seem to overlap in cases where a unit is not exclusively burning coal and requests clarification in the regulation of sources which blend fuels to clearly delineate which standards apply in cases where fuel blending is employed. Commenter cites an example where a coal-fired unit which burns more than 10 percent petcoke could arguably either fall under the solid oil-derived fuel subcategory or the coal-fired subcategory:

a. The commenter states that the proposed rule defines "oil" as "crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petcoke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas)." The commenter states that the proposed rule further defines the "unit designed to burn solid oil-derived fuel subcategory" as "any EGU that burned a solid fuel derived from oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or any one of those calendar years, either alone or in combination with other fuels." According to the commenter, consequently, if a coal-fired unit burns more than 10 percent petcoke, it could arguably fall into the solid oil-derived fuel subcategory.

b. The commenter states that however, the coal-fired subcategory also indicates that it includes units burning petcoke. The commenter states that the proposed rule defines a coal-fired unit as a unit that "burns coal or coal refuse either exclusively, in any combination together, or in any combination with other fuels in any amount."

Commenter 17774 urges the EPA to clarify which standards apply to units burning coal and petcoke and suggests that the EPA require affected sources to comply with the standard applicable to the majority of fuel burned (e.g.*,* greater than 50 percent).

Comment 24: Several commenters (19536, 19537, 19538) provides comment in response to the EPA's request to comment on, "whether the proposed rule should address how sources that change fuel input (e.g., burn solid waste or biomass), or otherwise take action that would change the source's applicability…must demonstrate continuous compliance with all applicable standards." Commenters state that EGUs designed to fire solid fossil fuels burn a mixture of coal types as well as other solid fuels including solid oil-derived fuels (petcoke), biomass, and other solid fuels. Commenters suggest that any subcategorization must be based on design differences which materially affect the availability of cleaner fuels, or other methods of reducing pollution. Commenters take the position that where a plant voluntarily (or for economic reasons) chooses to burn a high-polluting fuel, that decision should not affect the standards applicable to the plant, with one exception: the agency is obligated to distinguish between EGUs that are waste combustors (and thus subject to stricter standards governing waste combustors) from EGUs that are primarily fossil-fueled. Commenters concur with the EPA's proposed rule definitions for the solid fuel subcategories defining coal fired units as, "electric utility steam generating unit meeting the definition of 'fossil fuel-fired' that burns coal or coal refuse either exclusively, in any combination together, or in any combination with other fuels in any amount (76 FR 25122, Proposed section 63.10042 definitions). The commenters state that "Fossil fuel-fired," in turn, is defined as, "to the extent that an EGU that is capable of burning primarily coal or other solid fossil fuels to generate electricity, and also elects to co-fire biomass to meet some other statutory requirement, it must continue to meet the MACT limits for the subcategory in which it is listed." Commenters add that this is particularly important for biomass, as burning green wood produces more of various regulated HAP than does burning coal (Commenters cite Figure 1 in Docket No. The EPA-HQ-OAR-2009-0234). Commenters also add that it would be unlawful for the EPA to finalize a MACT subcategory that would worsen the HAP emissions profile of the EGU beyond what it would be absent the biomass burning.

Response to Comments 23 - 24: As noted elsewhere in this document, the EPA has revised the definitions to address commenters' concerns.

9. Disagreement That the EPA Did Not Use Best Available Data/Information to Support Fuel Switching Analysis for Proposed Rule with Respect to Natural Gas

Comment 25: Commenter 17810 states that natural gas is currently under-utilized for power generation and could be called into duty very quickly to provide clean energy and an immediate pollution reduction. In addition to significant HAP reductions, the commenter states that emissions reductions in NO_X and SO_2 can be realized from fuel switching (coal to natural gas) in the power generation sector. Commenter recognizes that the EPA may not consider it realistic to require all coal plants to shift to natural gas by setting a beyond-the-floor standard based on natural gas combustion; however, points out that some owners and operators may find that converting to natural gas (retrofit, repowering, new construction, or use of underutilized existing plants) is a cost-effective compliance strategy. Commenter concludes that efficiency benefits of NGCC combined with natural gas and coal price projections make NGCC clearly preferable to advanced coal-fired boilers for new base-load generation, citing IPM runs commissioned by commenter and review of the EPA's IPM results. Commenter cites that the EPA shows in the IPM results that no new pulverized coal capacity is added through 2030, even in the base case, while 68 GW of NGCC capacity is added under the base case assumptions and 75 GW of NGCC capacity is added under the policy case assumptions through 2030 (EPA, *IPM Analysis of the Proposed Toxics Rule*, March 2011, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html). Commenter states that it is important for the EPA to use accurate and current data to appropriately characterize the most up-to-date natural gas infrastructure, supply, cost, and technology associated with natural gas availability, and cites several areas of disagreement with the EPA's assumptions used in development of the Proposed Rule:

a. For existing EGUs, Commenter 17810 cites that the EPA determined that fuel switching (coal to natural gas) was not an appropriate beyond-the-floor option, citing two primary reasons: (1) natural gas supplies are not available in some areas, and (2) increased fuel costs cause a unit's total incremental cost of electricity (COE) to be significantly higher compared to the incremental COE of other options. Commenter 17810 states that the EPA included only two documents to justify these conclusions (*Technical Support Document [TSD] for the Transport Rule [sic]*, "Coal-to-Gas Conversion (C2G)" (March 4, 2011) and Documentation Supplement for EPA Base Case v4.10_PTox – Updates for Proposed Toxics Rule (March 2011), available at http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/suppdoc.pdf, Docket ID No. The EPA-HQ-OAR-2009-0234). Commenter states that both these documents are associated with the cost of coal-to-gas conversion, but that neither addresses the natural gas supply issue, and cites several references to the contrary (Docket ID No. The EPA-HQ-OAR-2009-0234). Commenter 17810 states that there does not appear to be any evidence in the record to support the conclusions that natural gas pipelines are not available in all regions of the U.S., natural gas may not be available as a fuel for many EGUs, and even where pipelines provide access to natural gas, supplies of natural gas may not be adequate, especially during peak demand (e.g., the heating season). The commenter states that currently available information refutes the notion that there is insufficient supply or inadequate infrastructure to support increased demand for natural gas for EGUs. The commenter states that recent estimates from both the U.S. Energy Information Administration (EIA) and the MIT Energy Initiative indicate sufficient supply to meet increasing demand for natural gas-fired EGU capacity. According to the commenter, the actual delivery of supply to a specific consuming market occurs hand-in-hand with the development of demand, and the delivery of supplies into the vicinity of an EGU should not be expected to precede the demand from an EGU by a period of years.

i. According to the commenter, the EPA's analysis of costs of constructing new laterals to distribute gas to existing coal-fired units demonstrates that some coal-fired power plants have relatively inexpensive access to natural gas mainlines, while other coal-fired power plants will have a more difficult time accessing natural gas mainlines, but the analysis appears to contradict the EPA's statement that natural gas pipelines are not available in all regions of the U.S. The commenter states that the average coal-fired boiler at a power plant that does not already have access to natural gas would need 57.4 miles of pipeline to meet natural gas demand, and the median pipeline requirement is 26.2, meaning that 50 percent of coal-fired power plants would need 26.2 miles or less of additional pipelines. The commenter states that while this suggests that in some cases access to natural gas may require significant investment and construction, it does not support the idea that natural gas is unavailable.

ii. According to the commenter, the recently released INGAA Foundation study of midstream infrastructure needs indicates that natural gas producers are playing an important role in funding needed pipeline infrastructure as they compete to deliver their natural gas to markets.

iii. The commenter states that according to the U.S. EIA, "the U.S. natural gas pipeline network is a highly integrated transmission and distribution grid that can transport natural gas to and from nearly any location in the lower 48 States."

iv. The commenter states that Department of Energy figures indicate that the interstate and intrastate transmission network feeds over 1.1 million miles of regional lines in some 1,300 local distribution utility networks, collectively delivering natural gas to 62 million customers in the U.S.

v. According to the commenter, the natural gas industry has shown an ability to respond to changing market conditions. The commenter states that according to EIA, 3,893 miles of new natural gas pipelines were added in 2008 alone.

vi. The commenter states that the recent INGAA Foundation study includes FERC data showing from January 2000 to February 2011, interstate pipeline companies received approval to construct over 16,000 miles of interstate pipelines and add an additional 14,600 miles of expansion pipeline. According to the commenter, the INGAA Foundation projects similar development over the next 10 years.

vii. The commenter states that according to a recent report issued by the MIT Energy Initiative on the Future of Natural Gas ("MIT Natural Gas Report"), the production and delivery infrastructure of natural gas in the U.S. is "both mature and robust." The commenter states that major changes in U.S. gas markets have prompted significant additions to the country's pipeline network over the last several years; between 2005 and 2008, pipeline capacity additions totaled over 80 billion cubic feet per day (Bcfd), exceeding those from the previous four-year period by almost 100 percent. Additions of 44.5 Bcfd in 2008 alone exceeded total additions in the five-year period between 1998 and 2002. According to the commenter, MIT's Interim Report to the Future of Natural Gas noted, "On the gas infrastructure side, concerns have been raised about the availability of gas pipeline capacity for the additional gas requirements of this option [displacement of coal generation], but preliminary analysis indicates that the industry has the ability to meet the needs for additional pipeline capacity." The commenter states that the MIT Natural Gas Report concluded that: (a) there are abundant supplies of natural gas in the U.S., despite their relative maturity, natural gas resources continue to grow; (b) the role of natural gas is likely to continue to expand under almost all circumstances, as a result of availability, utility, and comparatively low cost; and (c) increased utilization of existing NGCC power plants provides a relatively low-cost short-term opportunity to reduce U.S. carbon dioxide emissions by up to 20 percent in the electric power sector and significantly reduce sulfur dioxide, nitrous oxide, particulates, and mercury with minimal additional capital investment in generation and no new technology requirements.

viii. The commenter states that the FERC also noted significant recent increases in the storage capacity for natural gas. The commenter states that more than 107 Bcf of incremental working gas capacity was added in 2009, including more than 50 Bcf in the Gulf region. The commenter states that traditional production area storage allows suppliers to respond more adeptly to market signals, and as a result, those signals are moderated. The commenter states that reporting on 2010 storage, the FERC said, "Natural gas storage levels were high for much of the year and reached record levels in November."

ix. The commenter states that generally speaking, estimates of the available domestic supply of natural gas have expanded significantly over just the past five years. According to the commenter, in a 2009 Report addressing the supply of technically recoverable natural gas in the United States at

2008 year-end, the Potential Gas Committee reported that the currently available total supply of natural gas was 1,836 trillion cubic feet (Tcf), which represented an increase of 39 percent (516 Tcf) over the Committee's year end estimate for 2006. The commenter states that in the 2011 Report, the Potential Gas Committee increased this estimate to 1,898 Tcf. According to the commenter, the MIT Natural Gas Report also reviewed U.S. gas resource estimates from several sources, including the 2009 Potential Gas Committee Report, and assumed a mean remaining resource base of approximately 2,100 Tcf. The commenter states that the U.S. EIA recently estimated that annual production of natural gas will increase by 25 percent from 2009 to 2035. According to the commenter, many of these sources attribute this dramatic increase in recoverable natural gas supplies in large part to the discovery of significant shale gas deposits and advances in technology for recovery of gas from these resources.

x. The commenter states that studies have concluded that not only is there an expanding supply of natural gas, but due to declining costs of recovering that gas, domestic gas production is likely to increase significantly. According to the commenter, as summarized in a recent report issued by the Bipartisan Policy Center and American Clean Skies Foundation, "While estimates of supply have increased, the cost of producing shale gas has declined as more wells have been drilled and new techniques have been developed and field tested. The commenter states that the MIT study estimated that between 250 and 300 Tcf of shale gas can be produced at prices below $8/MMBtu (in 2007 dollars), and more recently, ICF International estimated that almost 1,500 Tcf are available at $8/MMBtu, while 500 Tcf are available at $4/MMBtu and 1,500 Tcf are available $5/MMBtu (ICF Figure 1 included in Docket EPA-HQ-OAR-2009-0234).

xi. According to the commenter, significant changes have occurred both with respect to natural gas supplies and storage infrastructure over the past 10 years that alleviate heating season supply concerns. With respect to storage, the commenter states that FERC reports in the *State of the Markets Report* that in late November 2009, U.S. inventories were 99 percent of capacity, suggesting that there is sufficient gas reserve capacity to address demand spikes during the heating season. The commenter states that greater reliance on shale extraction methods in the production process helps mitigate concerns about responsiveness on the supply side when demand increases. According to the commenter, unlike conventional production, in which a producing well needs to be kept "on" in order to maximize the amount of recoverable gas, production from shale wells is far more elastic, allowing producers to ramp up production in response to price signals, thereby helping to avoid the dramatic price swings that happen when it takes longer for production levels to respond to changes in demand.

b. For new EGUs, Commenter 17810 states that the EPA fails to consider best available data on supply and cost when identifying beyond-the-floor options. According to the commenter, in making the determination that fuel switching to natural gas is not a reasonable option, the EPA falls back on a generic statement that natural gas supplies are not available in some areas; whereas, commenter posits that it establishes with the above references that natural gas is widely available throughout the country and new power plants can be sited with pipeline capacity and proximity as a key consideration. Commenter states that the EPA also suggests that "limited emissions reductions in combination with the high cost of fuel switching and considerations about the availability and technical feasibility makes this an unreasonable regulatory option that was not considered further." Commenter states that this statement, without supporting data or discussion, is not sufficient to eliminate the consideration of a beyond-the-floor option. Commenter 17810 states that they are not aware of technical challenges associated with designing and constructing a new unit to combust natural gas instead of coal, and suggests that the EPA evaluate the cost of a new NGCC unit for providing base load power as compared to a new advanced coal-fired boiler. Commenter cites the EPA's modeling in support of the rule, which projects no new advanced coal-fired boilers to be constructed through 2030, even in the base case scenario without imposition of the rule.

c. Commenter 17810 cites other regulatory contexts where it says that EPA has read similar provisions of the CAA to include the use of lower-emitting processes and practices, including switching to cleaner burning fuels:

> i. BACT Guidance issued in March 2011 includes switching to clean fuel as a "control option" for purposes of performing a BACT analysis under the PSD program.
>
> ii. BART guidance under the Regional Haze program includes inherently lower emitting processes, such as processes using cleaner fuels, as "potentially applicable retrofit control technologies."

Comment 26: Commenter 17852 states that switching from coal-fueled electric power generation to generation from natural gas or renewable energy can achieve substantial reductions in toxic air emissions, stating that natural gas plants emit no mercury and negligible other HAP in contrast to coal. Commenter adds that numerous modern, high-efficiency NGCC plants with significant unused capacity are available to replace existing coal-fired generation and that dramatically expanded U.S. natural gas reserves and infrastructure have reduced gas price volatility (citing several references in the Docket EPA-HQ-OAR-2009-0234). Commenter 17852 recommends that the EPA re-evaluate the docket and issue specific guidance and indicate in the preamble to the utility MACT final rule that fuel switching to natural gas is a means to comply with the standard, providing guidance how various types of fuel switching to natural gas can allow coal/oil units to comply, including:

a. Converting existing coal boilers to natural gas;

b. Retiring coal plants and building new natural gas plants (either at the same location or a new location);

c. Increased co-firing with natural gas; and

d. Increasing use of existing, underutilized natural gas power plants.

Commenter 17852 states that the EPA made several unsupported assumptions in rejecting natural gas as a compliance option and cites several references (included in Docket EPA-HQ-OAR-2009-0234) to support this point:

a. Commenter 17852 states that, in comparing costs for fuel switching to natural gas, the EPA only focuses on one type of fuel switching (converting existing coal boilers to natural gas, which results in a loss in boiler efficiency). Commenter states that a more logical evaluation would be to compare the expensive retrofits facing existing coal plants to retiring the aging plants and either using existing natural gas generation from unused capacity or building a new NGCC (at same location or new site). Commenter adds that the EPA's analysis also ignores the possibility of co-firing natural gas in coal or oil-fired boilers. Commenter conducted such an economic evaluation and found that the break-even gas price for increasing use of existing NGCC vs. retrofitting coal plants with a scrubber and SCR is approximately \$6/MMBtu. Similarly, commenter's evaluation found that the break-even price for building a new NGCC is approximately \$5.50/MMBtu. According to the commenter, thus, using the natural gas prices that the EPA assumes in their fuel switching analysis (\$5.74/MMBtu), increasing the use of available capacity from an existing NGCC is the economical choice, and building a new NGCC is virtually equivalent. Commenter adds that the economics for using natural gas improve when including additional costs that may be imposed on coal-fired power plants under other regulatory initiatives.

b. Commenter 17852 states that the EPA finds coal to gas retrofits more expensive than other retrofit options based on fuel prices of coal at $2.13/MMBtu and natural gas at $5.74/MMBtu, despite the capital and O&M costs of the coal to gas retrofits being less expensive than other options.

c. Commenter 17852 states that it should be recognized that the EPA's assumed natural gas price ($5.74/MMBtu) only assumed installation of scrubbers and SCR, but if additional controls are required (e.g., coal ash, cooling water issues), it can become more economical to shutter old coal plants and build new NGCC plants.

d. The commenter states that with respect to co-firing with natural gas, the EPA notes that, "For the oil-fired subcategory, we did not include data obtained from EGUs co-firing natural gas in the existing source MACT floor analysis because those emissions are not representative of EGUs firing 100 percent fuel oil (76 FR 25045). Commenter 17852 recommends that the EPA should clarify in the guidance that co-firing with natural gas can reduce the emissions of either coal or oil-fired units and may be an effective means of compliance.

e. Commenter cites that the EPA has found that regulation of HAP emissions from natural gas power plants, "is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible."

f. Commenter refutes the EPA's contention that natural gas may not be a cost effective option, stating that fuel switching to natural gas is made more feasible by the fact that dramatically expanded U.S. natural gas reserves and infrastructure have reduced gas price volatility and are projected to make natural gas affordable for the foreseeable future. Commenter cites that the EPA RIA for the proposed rule includes projections that natural gas prices are not expected to exceed their 2008 Levels through 2035 and that the EPA projects that the proposed MACT standard would increase power sector delivered natural gas prices by only about 1% percent from 2015-2030, which is a negligible increase and shows the ability of natural gas to provide fuel to power plants without dramatically increasing natural gas prices (Figure 1, 2010 to 2011 Annual Energy Outlook of the EIA included in Docket EPA-HQ-OAR-2009-0234).

g. Commenter 17852 cites their own reports and studies, adopted by a task force that represented natural gas producers and distributors, consumer groups, large industrial users, and independent experts, which found that abundant natural gas supplies coupled with increased storage and import capability, as well as the ability to use long-term contracts and hedging arrangements, provide for a stable natural gas price horizon and opportunity to expand use in the U.S. Commenter states that the EPA must take into account their recent studies, which show that available gas-fired generation capacity exists in most regions of the U.S. According to the commenter, their report found that in 2008, CCGT plants operated with only a 33% capacity factor. If only the more efficient group of CCGT plants (heat rate of 9,000 Btu/kWh) were operated at 60% of capacity instead of at 33 percent, ACSF's report (which also cited a MIT report) indicates that could replace up to 60,000 MW of out-of-compliance base load units that may be retired. The commenter states that the geographic distribution of this available CCGT capacity is rather well aligned with the location of most vulnerable coal-fired units (Figure 2, Docket EPA-HQ-OAR-2009-0234).

h. Commenter 17852 cites that the MIT report also found that there is sufficient surplus NGCC capacity to displace roughly one-third of U.S. coal generation. The commenter states that according to MIT, substitution of this NGCC capacity would reduce CO_2 emissions from the power sector by 20 percent and yield a major contribution to the control of criteria pollutants.

i. Commenter refutes the EPA's contention that natural gas pipelines are not available in all regions of the U.S., citing the EPA's own data. The commenter states that as part of the rulemaking, the EPA undertook an analysis for coal boilers in the U.S. to "determine the miles and associated cost of extending pipeline laterals from each boiler to the interstate natural gas pipeline system." According to the commenter, this study found that the median connection length is only approximately 26 miles and the median incremental cost is only approximately $14 million. The commenter states that given that environmental retrofits for coal plants may cost hundreds of millions of dollars, $14 million for the median cost of a new gas lateral connection is comparatively minor. Commenter adds that the EPA may have used assumptions that overstated the length and cost of these new gas connections. Commenter also cites that the Department of Energy (DOE) has found that that natural gas lines can, "deliver fuel to power plants in most locations in the lower 48 states." Commenter recommends that the EPA correct the record.

j. Commenter refutes the EPA's contention that, "even where pipelines provide access to natural gas, supplies of natural gas may not be adequate, especially during peak demand (e.g., the heating season)." Commenter points out that the development of shale gas has vastly increased onshore gas production, gas storage capacity has increased over the last few years, and the FERC has been responsive to the need for additional pipeline capacity to bring gas to new markets. Commenter acknowledges that, while it is possible that unforeseen emergencies may create temporary curtailment, these types of emergencies are manageable, and not unlike other energy delivery issues that occasionally occur.

Comment 27: Commenter 17853 states that the EPA has the authority granted in section 112 of the CAA to consider fuel switching as an alternative to achieving emission reductions during the development of the Utility MACT and refutes the EPA's statement in the preamble that "supplies of natural gas may not be adequate" with the following points:

a. According to the commenter, at current consumption rates, North America has over a 100-year supply of natural gas.

b. According to the commenter, natural gas drilling and extraction technologies (including shale gas) have dramatically improved over the last 5 years, and the lead time to respond to increased demand has been significantly decreased thus reducing price volatility. The commenter states that the Potential Gas Committee of the Colorado School of Mines releases a biennial assessment of the nation's natural gas resources, and review from the 2006 assessment to the 2011 assessment indicates an increase in natural gas total resource base from 1,321 to 1,898 trillion cubic feet (44 percent).

c. According to the commenter, in addition to the natural gas available within the U.S., the natural gas pipeline transmission systems of the U.S. and Canada are highly integrated, providing access to Canada's vast gas reserves, which coupled with Canada's relatively small population, provides the U.S. with an additional reliable source to help meet rising demand.

d. The commenter states that according to the U.S. EIA Annual Energy Outlook 2011 projections, production from shale formations in the U.S. grew by an average annual rate of 17 percent per year from

2000 to 2006, and in the years from 2006 to 2010, U.S. shale gas production grew by an average annual growth rate of 48 percent.

e. According to the commenter, the natural gas industry has proven the ability to develop and distribute natural gas required to meet increased demand from the EGU sector into the future.

f. Commenter states that the EPA's analysis on fuel switching is flawed because it mistakenly presumes retired generation must be replaced by building a gas-fired unit in the same footprint. According to the commenter, with greater reliance on local resources, retiring coal-fired EGU capacity can be replaced by natural gas-fired EGUs built closer to load, reducing dependence on interstate pipelines.

g. The commenter states that historical trends also demonstrate that concerns over natural gas availability and abundance are unfounded. The commenter states that according to the July US EIA Natural Gas Monthly report, "nearly 237 GW of natural gas-fired power generation capacity were added between 2000 and 2010, representing over three-fourths of total generation capacity additions over that period." The commenter asserts that despite this growth in natural gas-fired generation capacity additions, natural gas prices in 2010 remained relatively low and production rates of natural gas continue to grow.

Commenter 17853 states that an immediate HAP benefit to the environment can be realized by increasing utilization of existing and new natural gas-fired EGUs and cites the results of the Utility Study and the preamble to the proposed rule as accurately depicting that the emissions of priority HAP from natural gas-fired EGUs are negligible compared to coal. Commenter adds that natural gas-fired EGUs also deliver significant emission reductions of PM, SO_2, NO_X, CO_2, VOC, and regional haze precursors.

Commenter 17853 points out that the EPA did not consider increased zero HAP emitting base-load capacity as a fuel switching alternative. According to the commenter, since natural gas is not the only source for power generation outside of coal combustion, the EPA could consider including a "fuel neutral" fuel switching requirement which provides offsets for increasing zero HAP base-load generation directly towards a corresponding decrease in coal-fired generation.

Response to Comments 25 - 27: The EPA declined to propose as a beyond the floor level of control a requirement that coal- and oil-fired EGUs convert to natural gas. For existing sources, we indicated that we did not believe the supply of and transmission infrastructure for natural gas were sufficient to convert all existing units to natural gas. 76 FR 25046. We also determined that the incremental cost of electricity (COE) for converting all existing coal- and oil-fired EGUs to natural gas would be between 4 and 22 times the costs of compliance with the MACT floor level of control. *Id*. For new EGUs, similar to that for existing EGUs, we determined that natural gas was not available in all parts of the country. We also concluded that we would decline to adopt a requirement that all new EGUs be natural gas-fired even if we concluded that natural gas supplies were available because it would effectively prohibit construction of new coal-fired EGUs and we did not believe that to be a reasonable approach to regulating HAP emissions from EGUs. 76 FR 25049. We are not revising our decision in this final rule in response to the comments and we address commenters' specific points below.

Commenters cite studies and reports that show that the supply of natural gas is growing, that the cost of natural gas is generally stable, and that the availability of natural gas is expanding. One commenter even notes that one study specifically considered such issues in the context of the proposed EGU NESHAP. Even assuming all the studies are accurately characterized, the results do not in any way support a determination that conversion of all coal- and oil-fired EGUs to natural gas is cost effective or that the supply and transmission capabilities are sufficient to support such a conversion. The commenters maintain that the supply is currently sufficient and that the transmission capabilities are expanding, but no commenter indicates that the current situation (or the situation within three years) would allow a wholesale conversion to natural gas. The highest estimate provided by commenters is that one third of the coal-fired generating capacity could be replaced. Even being able to replace one third of the coal generating capacity with natural gas**,** this clearly falls short of the amount of fuel switching that would be necessary to set a beyond the floor standard at levels that would require all existing coal units to switch to natural gas. In addition, we continue to believe that a final rule that expressly prohibits new coal construction is not reasonable. For all these reasons, we maintain that our proposed determination not to require switching to natural gas as a beyond the floor level of control remains valid.

We also note that commenters appear to conflate the availability of natural gas as a cost effective compliance alternative with the availability of natural gas as a beyond the floor requirement applicable to all sources in a particular subcategory. We acknowledge that some sources will co-fire natural gas with coal or oil as a compliance option and that other EGUs will be converted to burn 100 percent natural gas. Both approaches are valid means to comply with the standards contained in the final rule; however, the availability of these compliance alternatives does not support a determination that natural gas conversion is available for all EGUs as a beyond the floor MACT standard.

The EPA did not presume as one commenter suggests that all new natural gas units must be located at current EGU facilities, but when evaluating whether to establish a beyond the floor level of control for a existing sources the agency does consider what the subject EGUs would have to do to comply with the beyond the floor standard.

10. Concurrence and caution for delegation of state programs.

Comment 28: Commenter 17810 recognizes the EPA's authority to delegate authority to implement section 112 rules and regulations in section 112(l) to states, provided that the state program is "no less stringent" than the federal program with respect to quantity of emissions, rule applicability, and level of control. Commenter has supported such state programs, including the Colorado Clean Air-Clean Jobs Act, and concurs with the EPA that these type of programs will ultimately result in significant emission reductions from coal-fired EGUs, as companies implement strategies (e.g., retirement/replacement with natural gas or other "cleaner" generation) and/or technologies (e.g., state-of-the-art controls) to meet the requirements. Commenter cautions that they expect that the EPA should look very closely at state programs or rules that have compliance dates beyond those contained in the federal rule to ensure that these programs merit greater reductions in HAP emissions beyond the federal rule to justify the extended compliance deadline.

Response to Comment 28: Response to this comment may be found in the preamble to the final rule.

11. Concerns from non-continental EGU sources.

Comment 29: Commenter 18477 expresses concern that the proposed rule mistakenly assumes that switching to natural gas or co-firing with natural gas is a valid and cost-effective compliance option for liquid oil-fired units; however, there is no natural gas or liquid natural gas resource in Hawaii. The commenter states that as a remote island utility, it does not even have access to the small amount of refinery gas available to the refiners addressed by the Boiler MACT.

Commenter 18477 states that all oil-fired EGUs operating in Hawaii, Guam, and Puerto Rico exclusively combust residual fuel oil to generate electricity, and all are limited by the crude slates of their fuel suppliers. The commenter states that its contracts with on-island refineries contain fuel specifications for factors such as sulfur content, pour point, flash point, API gravity and viscosity, which the refiners are able to meet primarily by blending and some sulfur removal. However, they do not and cannot economically control for metal content. The commenter states that as the agency noted in the preamble to the Boiler MACT, the quality of the fuel produced by non-continental refineries is limited by the quality of the crude slate used in the refining process (76 FR 15,635).

Commenter 18477 states that it is not feasible for non-continental liquid oil-fired EGUs to comply with the proposed numeric emission standards based on their survey of equipment control vendors. The commenter states that the vendors surveyed uniformly responded that they cannot guarantee their equipment can meet the proposed HAP limits for liquid oil-fired EGUs. The commenter states that the ability to achieve HAP control with residual fuel oil applications and ESPs or multi-cyclones in utility type boilers is currently being researched and is not a commercially demonstrated technology. According to the commenter, bag-houses are not a suitable technology for particulate matter control for residual fuel oil applications. The commenter states that reputable dry and wet ESP suppliers, such as Alstom, Babcock & Wilcox, PECO, Siemens, Southern Environmental Inc., Clyde Bergemann, Hamon Research-Cottrell, and Allied Environmental Solutions, Inc. were contacted to determine their current position on providing ESP guarantees to meet the proposed emission limits for liquid oil-fired units, and the companies that have provided feedback thus far will not guarantee that currently available technology can achieve the proposed emissions limits for residual fuel oil applications. Commenter included Attachment C as a summary of the vendor responses in the Docket No. The EPA-HQ-OAR-2009-0234.

Comment 30: Commenter 18502 states that because they are a non-continental facility, the availability of alternate fuels is limited. The commenter states that there are no fossil fuel resources on the island (Puerto Rico) and that the fuels presently used are delivered by ocean tankers, which is a possible source chloride contamination of the fuel as indicated by the erratic HCI measurements made during the ICR testing (HCI emissions varied by a factor of 20).

Commenter 18502 states that it has a long term plan for converting their steam generators, CCs, and CTs to co-fire natural gas (NG), but the infrastructure needed to deliver natural gas does not currently exist. The commenter states that the long term plan involves participation in expansion of a local LNG facility operated by EcoEiectrica and actively pursuing installation of a NG pipeline. The commenter states that engineering evaluations and permitting for the pipeline is underway, but completion has not been established yet.

Response to Comments 29 - 30: As noted elsewhere in this document, the EPA is establishing a non-continental liquid oil-fired subcategory in the final rule.

5C04 - Compliance: Switching subcategories

Commenters: 17402, 17621, 17638, 17681, 17736, 17754, 17772, 17781, 17790, 17796, 17800, 17868, 17881, 17902, 18014, 18018, 18444, 18449, 18498, 18502, 19033

1. Performance testing.

Comment 1: Commenter 17402 requests that the EPA allow facilities to set the capacity level at which a plant operates during a performance test. The commenter stated the EPA in allowing this will be providing another option for compliance, particularly as facilities transition and install new control equipment. According to the commenter, this approach will not cause an increase in emissions given that the facility would be limited in its ability to exceed the capacity level at which it is operating during the test.

Response to Comment 1: Pursuant to section 63.10007(c), performance tests are to be conducted under normal operating conditions. Unlike the proposed rule, there is no operating limit established in terms of 110% of the capacity level used during the most recent performance test.

Comment 2: Commenter 17754 states that the proposed rule should be revised to clarify that an affected source may elect to perform and/or rely on performance testing for the PM surrogate as the basis for initial and continuous compliance with total non-Hg HAP metals emission limit.

Commenter 17754 states that the EPA should not require an owner/operator of an affected EGU who elects to demonstrate compliance with total non-Hg HAP metals using the PM surrogate to conduct performance testing for both PM and total non-Hg HAP simultaneously. According to the commenter, the EPA should revise the rule to allow that if an owner/operator elects to comply by using the PM surrogate, the owner/operator is not required to conduct performance tests for both PM and total non-Hg HAP. The commenter states that the rule should be revised to provide that if a facility elects to conduct simultaneous performance testing of the PM surrogate and total non-Hg HAP metals, and as a result demonstrates compliance with one of the limits while exceeding the other, the affected EGU shall be deemed to be in compliance.

Commenter 17781 states it is inappropriate to require units relying on a surrogate to also conduct performance testing for the associated surrogate pollutant(s). According to the commenter, this approach is inconsistent with other 40 CFR part 63 standards which allow use of surrogates. The commenter states that the EPA has provided no rationale for the collection of this additional data.

Response to Comment 2: In response to comments, the final rule has removed all requirements for duplicative testing of a HAP and a surrogate pollutant. Facilities complying with a surrogate standard will conduct the performance test for that standard, and not for the corresponding HAP (and vice versa).

Comment 3: Commenter 17796 objects to the initial performance test requirement for all source owners and proposes that once the initial performance test is conducted for PM and non-HAP metals, fuel sampling will be adequate to demonstrate compliance in lieu of stack testing. According to the commenter, stack testing should be no more frequent than every 6 months.

Response to Comment 3: The final rule does not contain the proposed fuel sampling and analysis compliance demonstration approaches. See the final preamble and discussion under Comment Code 5A. The final rule uses either CEMS, where applicable, quarterly performance testing, reduced testing under the LEE provisions, or annual testing with a PM CPMS for the filterable PM or non-Hg HAP metals limits that apply.

Comment 4: Commenter 17881 states this requirement creates confusion in regards to the actual compliance mechanism. The commenter asks that if a unit complying with the PM emission limit surrogate for non-Hg HAP metals conducts performance testing for both PM and multiple metals, what would happen if one or more of the individual metals were above the standard (or, although unlikely, total non-Hg metals are shown to be above the standard)?

Response to Comment 4: In response to comments, the final rule has removed all requirements for duplicative testing of a HAP and a surrogate pollutant. Facilities complying with a surrogate standard will conduct the performance test for that standard, and not for the corresponding HAP (and vice versa).

2. Test methods and methodology.

Comment 5: Commenter 17621 provided discussion of testing methods recommended for ICR data collection and compliance with proposed MACT limits.

a. Method 30B: Commenter 17621 states that Method 30B does not specify a MDL or require that one be determined. The commenter states that a tester must estimate in advance the minimum sample volume that will provide adequate mass of Hg for analysis for the specific source and analytical technique. This commenter states it is possible to state a minimum mass of Hg that must be collected on a sorbent tube to obtain an accurate measurement by a given analytical method. The commenter states that based on EPRI's reviews of many ICR Part III test reports, almost all samples were analyzed using thermal desorption/CVAAS. According to the commenter, this research indicates at least 10 nanograms should be collected on the front bed of the sorbent tube to ensure accurate results. According to the commenter, there are two reasons for this: 1) to minimize inaccuracy due to instrumental gas flow fluctuations that can distort the desorption peak shape, and 2) to raise the sample mass sufficiently above the background sorbent mercury level. The commenter states that test runs with loadings below 10 nanograms generally failed method quality criteria for one or more of the three samples.

Commenter 17621 states that EPRI has classified the adequacy of Method 30B to measure at the proposed MACT limit for new coal EGUs as uncertain based on reports from several stack testers that at high sample flow rates leakage and equipment failure has occurred.

Commenter 17621 believes it is uncertain whether Method 30B can, for liquid oil-fired EGUs, measure Hg accurately at the proposed MACT limit for existing EGUs, and will be unable to measure Hg for new units without excessively long (about 30 hours) test runs.

b. Method 5: Commenter 17621 states that it is not certain whether Method 5 sensitivity is adequate to support compliance monitoring at the MACT limits for total PM, as that will depend upon the relative proportions of filterable PM and condensable PM in the stack gas. According to the commenter, for a stack gas where PM emissions are predominantly filterable PM, the above methods will be able to measure accurately at the proposed total PM limit (0.03 lb/MMBtu) for existing coal-fired EGUs. The commenter states that at the proposed limit for new EGUs (0.05 lb/MWh, approximately 0.005 lb/MMBtu), Method 5 should still be sufficient to measure accurately by gravimetric analysis and whether the overall method accuracy, considering sampling variability, will be adequate at that emission rate is unknown. Commenter adds that field studies conducted by EPRI and others have identified problems with the accuracy of Method 5 at low emission levels. According to the commenter, results can be biased high or low depending on how the sample is collected. The commenter states that a recent study conducted by AEP and EPRI found that the material used for the particulate filter (glass fiber versus quartz fiber filter) can produce a significant bias in the results due to acid gas sorption on the alkaline material of glass fiber filters (EPRI, 2011). According to the commenter, the temperature of the sampling probe and filter also affects the amount of filterable PM collected, with the lower temperature collecting more filterable PM. The commenter states that the ICR Part III data include tests conducted at two different temperatures (250 °F and 320 °F) and with both types of filters, and that these variables introduce additional uncertainty into conclusions drawn from the ICR data, in addition to normal method variability.

c. Method 202: Commenter 17621 states that it is not certain whether the Method 202 sensitivity is adequate to support compliance monitoring at the proposed MACT limits for total PM, as that will depend on the relative proportions of filterable PM and condensable PM in the stack gas. According to the commenter, for a stack gas where the PM emissions are predominantly condensable PM, the mass collected in a 4-hour test will be sufficient for an accurate gravimetric measurement at the proposed total PM limit (0.03 lb/MMBtu) for existing coal units. The commenter states that at the proposed limit for new EGUs, approximately 0.005 lb/MMBtu, the collected PM residue is also sufficient to measure accurately by gravimetric analysis, but limited results of field testing indicate that the overall method accuracy may not be adequate at that emission rate. Commenter adds that a field study conducted by AEP at several coal-fired power plants found that revised Method 202 has high between-run variability (EPRI, 2011). The commenter states that in four replicate tests conducted with the same sampling conditions (probe temperature, PM filter type, and sampling duration), the relative percent difference (RPD) of the CPM measurements ranged from 25–78 percent. The commenter states that these were samples taken at different times and were not parallel train samples; however, process monitoring indicated that there were no upsets during the sampling periods. The commenter states that filterable PM samples taken from the same sampling trains had lower (6–27 percent) variability. Condensable PM emissions in the samples ranged from 0.0032 lb/MMBtu to 0.013 lb/MMBtu. The RPD of the replicates at the lowest emission rate, about twice the proposed MACT total PM limit for new plants, was 78 percent. According to the commenter, these findings indicate that the method does not provide sufficient precision to support compliance monitoring at the proposed limit for new coal-fired EGUs and may not provide sufficient precision at the proposed limit for existing coal-fired EGUs. Commenter also adds that an EPRI laboratory study of OTM-28 determined that modifications from the original Method 202 had reduced the positive bias due to aqueous-phase conversion of gaseous SO_2 to sulfuric acid (a condensable PM species) compared to original Method 202 (EPRI, 2009). The commenter states that the study also found that OTM-28 did not appear to capture sulfuric acid aerosol effectively. According to the commenter, as sulfuric acid is the predominant condensable PM species in coal-fired power plants, this finding may indicate that the revised Method 202 has a negative bias.

d. Methods 5 and 202: Commenter 17621 states that the combination of Methods 5 and 202 is sensitive enough to provide accurate gravimetric measurement at the proposed MACT limits for both existing and new coal-fired EGUs. According to the commenter, the precision of Method 202 may not be sufficient at the new EGU limit to support that determination.

Response to Comment 5: The EPA does not agree that all components of a test method composed of composite analyses need to be above the minimum detection limit to provide reliably accurate quantification of the total emissions. While the commenter focuses on the four components used to quantify total particulate matter, other test methods and pollutants would present similar influences. While it is common to collect less than a measureable mass in the nozzle and probe portion of particulate sampling trains, this has an insignificant impact on the filterable or the total particulate matter measurements when the quantity of material collected on the other components are above the levels which minimize measurement precision. In the test data from the mix of PM tests performed under the Part III ICR, there were few individual runs where the mass of particulate was below the mass that has routinely been determined to be the minimum detectable mass for the different components. For filterable particulate, only 51 test runs out of 1252 had less than 1.3 mg of particulate on the filter and probe wash. For inorganic condensable particulate, only 19 of the 772 runs reported a mass of less than 1.5 mg. Last, for organic condensable particulate, 30 test runs out of the 772 runs reported a mass of less than 0.5 mg. These weights are the approximate detection levels for these components of total particulate. There were no sources where the mass for all components were less than these levels. Therefore we would not expect that any source would be challenged to demonstrate that their emissions were less than the proposed total particulate level we proposed. Since we have selected filterable particulate as the alternate equivalent standard for non-Hg metals, there are only two measured components and the filter component is expected to have the majority of the PM. In reviewing the filterable PM data, a 4-hour source test with 5 mg particulate on the filter (the approximate mass above which Method 5 has a consistent precision) would have emissions of approximately 0.0014 lb/MMBtu. This emissions level is much lower than the filterable PM emissions limit we have established in this rule. As a result, we do not expect any sources to have problems in accurately quantifying their emissions either when they are near the emissions limit or near the LEE emissions level. We agree with the commenter concerning the influences on filter selection and filtration temperature on the determination of mass on the filter. Sources and source test contractors will be advised to insure that the filter media they use meets the requirements of Method 5 with respect to the reactivity to acid gases to insure that their measurements are not biased. A similar bias may arise as a result of maintaining the wrong filter temperature.

Comment 6: Commenter 17881 states the use of PM filterable will simplify the associated testing requirements in that a single Method 5/Method 29 sampling train could be used to simultaneously test for both the PM surrogate and multiple metals. According to the commenter, use of a PM filterable surrogate would also allow a direct compliance determination via the use of PM CEMS (which are only capable of measuring PM filterable emissions).

Response to Comment 6: In response to comments, the final rule has removed all requirements for duplicative testing of a HAP and its surrogate. Facilities complying with a surrogate limit do not have to perform periodic testing for the corresponding HAP. We agree with the commenter in that Method 29 provides the ability to concurrently quantify filterable PM and the non-Hg metals which we are regulating. The final rule uses a PM CPMS approach. See the final preamble and Comment Code 5A07a for further discussion.

Comment 7: Commenter 18444 states that the particulate filterable temperature is defined as 320 °F ± 25 °F, which is the temperature currently used for non-sulfate filterable PM testing, and this appears to be because the sulfate is to be counted with the condensables. According to the commenter, this is different than most of the EPA testing (248 °F ± 25 °F), so the filterable particulate results measured under these new requirements would likely be lower than what would be currently measured. The commenter states that since the limits are for the total PM (filterable and condensable) the total catch should in theory be the same regardless, but this would impact the PM CEMS (if used) since they will be measured on the filterable only. The commenter states that companies would have to test separately for compliance with different federal particulate limits based on these temperature differences, adding to the testing workload.

Commenter 18444 states the filter temperature for metals testing is defined the same as for particulates (320 °F+ 25 °F) instead of the current practice (248 °F + 25 °F). The commenter states that the proposed rules mention determining filterable metals separately from total metals, and as with PM, this impacts limits set for Hg CEMS or sorbent monitoring (if used) since particulate Hg is not measured by these methods. According to the commenter, in this case, there will be higher mercury results on the CEMS or sorbent monitoring since the higher filter temperature would allow more Hg to pass through the filter. The commenter states that as long as the EPA adopts stringent PM limits, that particulate Hg emissions will not be significant; monitoring gaseous Hg should be sufficient and the filter temperature should not change the gaseous Hg results significantly.

Response to Comment 7: While we deliberated what filter temperature should be used in the collection of test data with Method 5, Method 29, and Method 26A, we selected 320 ºF for multiple reasons. First, it is consistent with the temperature used for compliance with existing rules. As a result this allowed a mare direct comparison with that data and provided us with an understanding of the within source variability of emissions. It also provided a more direct ability to establish a particulate level for correlation or alternative applications of PM CEMS. The absence of SO_3 on the filter and the collection in the impinger provides for more consistency in obtaining constant weights. Since little or no SO_3 is retained on the filter, the highly hydroscopic SO_3 does not cause weighing difficulties by absorbing water from the air. Also, by moving the SO_3 to the impinger, the SO_3 can be neutralized and thereby making it easier to achieve constant weight. Lastly, it provided a partitioning of the components of particulate similar to the majority of the existing emissions controls.

Comment 8: Commenter 19033 states that the proposed regulation section 63.10005(b) specifies that performance tests are to be conducted; as specified in Table 5. With respect to the proposed PM limit, the commenter notes that the testing requirements are Method 5 and 202, with the specific provision that tests using Method 5 must be performed at a filter temperature of 320° F. However, some state permit conditions require that filterable PM, as measured by Method 5, be conducted at a filter temperature of 250 °F. Commenter adds that filterable PM measured by Method 5 at 250 °F is expected to provide different (and higher) results than filterable PM measured by Method 5 at 320 °F, because of the condensation of sulfuric acid at 250 °F. According to the commenter, consequently, a mechanism is needed to allow EGUs required to perform Method 5 tests at 250 °F to concurrently demonstrate compliance with the proposed PM limit based on a Method 5 filter temperature of 320 °F. Commenter 19033 suggests the following mechanism to accomplish the concurrent compliance demonstration:

1. Perform all required PS-11 PM CEMS correlation curve testing using EPA Method 5 at a filter temperature of 250 °F, if the state agency so directs.
2. Perform PM compliance tests with respect to the proposed limit at a filter temperature of 320 °F. According to the commenter, if compliance is demonstrated, the concurrent PM CEMS output (which will be biased high, because it will correlate to 250 ºF) will become the filterable concentration limits, rather than the three-run filterable PM concentration limit measured at 320 °F.

Commenter 19033 recommends revisions in Tables 4 and 7, in order to implement the above described mechanism. In conjunction with the changes recommended for Tables 4 and 7, Commenter 19033 also recommends that proposed regulation 63.10011 (d) be amended as follows:

> ... You must determine an operating-limit (PM concentration in mg/dscm) during performance testing for initial PM compliance. The operating limit will be the average of the PM filterable results of the three Method 5 performance test results, ***unless the state agency requires the Method 5 tests to be performed at a filter temperature of 250°F. If***

the Method 5 tests are required to be conducted at 250°F, the operating limit will be the average of the PM filterable results reported by the PM-CEMS rather than the PM filterable results of the three Method 5 tests performed at 320°F, provided compliance is demonstrated by the Method 5 tests conducted at 320°F.

Comment 9: Two commenters (18444, 19033) express concern over the EPA requirement that the stack test filter temperature is set at 320 °F when other regulatory authorities and/or State agencies may require a different lower temperature of 250 °F.

Response to Comments 8 - 9: The final rule has been revised to remove the requirements for Method 202 and PS-11, so those comments are moot. The 320°F filtration temperature was chosen for the determination of compliance with the standard due to match the data collection temperature. If sources would like to harmonize their testing requirements with other limits at lower filtration temperatures, they may request to do so per 63.7. The EPA agrees that there are biases associated with improper selection of filter material. Method 5 states that sources with SO_2 or SO_3 should select an unreactive filter to handle such issues. The EPA disagrees that Method 30B cannot measure the levels specified in the emission standards. The data used for the new source MACT limit were based on Method 30B 4 hour test runs that met all QA criteria with a catch under 10 nanograms. The EPA disagrees that we should set a specific ng catch for the method, but welcomes sources to devise test plans with those DQOs.

3. Test methods unreliable or inadequate.

Comment 10: Commenter 17736 states that including condensable PM raises concerns about the efficacy of monitoring technologies used to determine compliance. According to the commenter, measuring condensables separate from filterable PM is new and is not widely accepted by the industry due to a lack of data supporting the method's accuracy.

Response to Comment 10: As we state elsewhere, we evaluated the ability of all particulate components to be a surrogate indicator of non-Hg metals emissions. As a result of that evaluation, we have selected filterable particulate since it offers several advantages with respect to continuous monitoring and ease of demonstrating compliance. The comments regarding a supposed lack of condensable PM data and potentially inaccurate condensable PM test method are moot, not because we agree with either supposition but because the rule no longer contains a total PM emissions limit. With respect to accuracy, particulate matter is a pollutant that is sensitive to the method which it is collected. This includes not only how much material is in solid or liquid form but also the size distribution of the particulate matter. By establishing a truly standard collection hardware, conditions for the separation of the water and sample gas, temperature for collection and analytical finish we have also established the material which is retained and measured as PM.

Comment 11: Commenter 17881 states as currently written, section 63.10006(e) requires that the fuel factor methodology and equations in sections 12.2 and 12.3 of Reference Method 19 (40 CFR 60, Appendix A-7) be used to convert the results of the performance tests into units of lb/MMBtu of lb/TBtu, as applicable. This section should recognize that such calculations need not be conducted if an EGU has chosen to demonstrate compliance with the mass per unit of electrical output emission limits. The EPA should also allow the use of fuel factors determined in accordance with sections 3.3.5 and 3.3.6 of 40 CFR Part 75, Appendix F. Of particular concern is the fact that Reference Method 19 does not contain fuel factors for subbituminous coals, solid oil (i.e., petroleum coke) or tire-derived-fuel, any of which could be fired in solid fuel-fired boilers subject to the proposed rule.

Response to Comment 11: The EPA agrees, and has made corresponding changes to section 63.10007(c) in the final rule.

Comment 12: Commenter 18449 expressed the concern that, if the $\pm$1 µg/m3 alternate specification is tightened, an increased frequency of testing errors will cause even CEMS that are operating properly to fail. According to the commenter, the EPA should consider a mandatory periodic QA/QC program where it or another impartial agency loads sorbent traps supplied by the test group with the output from a NIST traceable elemental calibrator. The commenter states that this approach should be applied to both RATA testers and to suppliers of continuous sorbent testing services.

Response to Comments 12: The comment is moot because the final rule did not tighten the alternative specification.

4. Surrogates.

Comment 13: Commenter 17736 states that the EPA's proposed rule creates a double standard, facilitating potentially inconsistent enforcement practices. The commenter states that non-Hg HAP metals compliance provisions should be written to provide a unit electing to comply with a surrogate with continuing compliance demonstrated not to be deemed in non-compliance for exceeding an emission limit during a stack test.

Response to Comment 13: In response to comments, the final rule has removed all requirements for duplicative testing of a HAP and its surrogate. Facilities complying with a surrogate limit do not have to perform periodic testing for the corresponding HAP, and vice versa.

Comment 14: Commenter 17881 states Table 4 of the proposed rule, as well as section 63.10005(d)(4), indicate use of the SO_2 surrogate is predicated on the EGU both being equipped with wet or dry FGD and using an SO_2 CEMS for the compliance determination but that section 63.10006(h) applies to those solid oil-fired and coal-fired EGUs without SO_2 CEMS but with wet or dry FGD controls. The commenter states that such EGUs are required to conduct SO_2 and HCl testing during the same compliance test period and under the same process (i.e., fuel) and control device operating conditions at least every year, as well as conduct SO_2 testing at least every other month. The commenter states that this paragraph is confusing, as SO_2 is being treated as a regulated pollutant even though its use as a surrogate would appear to be barred in the absence of an SO_2 CEMS. According to the commenter, it is very unlikely that there are any solid oil-fired or coal-fired EGUs of sufficient size to be regulated under the proposed EGU MACT but not be equipped with SO_2 CEMS, as such CEMS are generally required by one or more of the following: 40 CFR Part 60, 40 CFR Part 75, and State Implementation Plans.

Response to Comment 14: In response to comments, the final rule has removed all requirements for duplicative testing of a HAP and its surrogate. Facilities complying with a surrogate standard will conduct the performance test for that standard, and not for the corresponding HAP (and vice versa). The specific provisions cited in this comment have been clarified in the final rule such that only the HCl testing would be required under such circumstances.

5. Test requirements.

Comment 15: Commenter 17772 submits that the testing requirements are excessive and unnecessarily redundant. According to the commenter, for units that do not use a PM CEMS, the proposed rule would require testing every other month, which is unjustified and costly. This commenter also states it is unclear how compliance is determined under the multiple testing scenario.

Comment 16: Commenter 17796 supports testing for filterable particulates as well as condensable PM.

Comment 17: Commenters 17638 and 17681 state that the EPA should not require HAP stack testing for EGUs using a surrogate, and should remove the requirement that EGUs using PM as a surrogate for non-Hg HAP metals conduct a stack test for non-Hg HAP metals. EGUs using SO_2 as a surrogate for HCl should not be required to stack test for HCl. Commenters also state that the EPA should not require stack testing of surrogates when a source chooses to comply with the HAP limit.

Commenter 17790 submits there is no justification for testing for the HCl surrogate (Method 502) if a company is complying with the HCl standard.

Commenter 17868 states that the EPA has no basis to require HAP stack testing for EGUs using surrogates or to require surrogate testing for EGUs not relying on surrogates. The commenter states that the requirements are duplicative and should be removed.

Commenter 17881 states it is inappropriate to require units relying on a surrogate to also conduct time consuming and costly performance testing for the associated surrogate pollutant(s). According to the commenter, this approach is wholly inconsistent with other 40 CFR Part 63 standards which allow the use of surrogates, and the EPA has provided no rationale for the need to collect this additional data. The commenter states that if the EPA is concerned about the relationship between the chosen surrogates and their associated HAP(s), then the EPA should initiate an additional ICR effort which will allow them to further study the relationships between HAP(s) and their potential surrogates.

Commenter 17881 states that the provisions of section 63.10006(i) are very similar to those in section 63.10006(d) in that they require testing of both the surrogate (i.e., SO_2) and the associated HAP (i.e., HCl) even though the surrogate cannot be relied upon for compliance for solid oil-fired and coal-fired EGUs without a SO_2 CEMS and without wet or dry FGD controls.

Commenter 18498 states that the requirement to stack test for both the pollutant and surrogate is redundant, and requests the EPA to remove the requirement that both the pollutant and surrogate be stack tested. According to the commenter, a performance test should only be required for the pollutants and surrogates with which a source is choosing to show compliance.

Multiple commenters (17638, 17681, 17754, 17772, 17781, 17790, 17800, 17881) express the concern that requiring testing for both a pollutant and its surrogate is unnecessary when only one should be adequate for demonstrating compliance.

Commenter 17800 states that requiring sources to test either for the actual HAP in cases where surrogates are being used for compliance is duplicative, has no rational to be required, and will increase the cost of compliance.

Commenter 17881 states that the provisions of section 63.10006(d) require that petroleum coke and coal-fired EGUs without PM CEMS (but with PM control devices) conduct all applicable tests for PM and non-Hg HAP metals testing during the same compliance test period and under the same process (i.e., fuel) and control device operating conditions at least every year, as well as conduct non-Hg HAP metals testing at least every other month. The commenter states that the PM surrogate only applies to those units equipped with a PM CEMS, so it makes no sense that such units are required to conduct concurrent PM and non-Hg HAP metals testing, as PM is not a regulated pollutant for such units. The commenter states that as discussed in relation to 63.10005(a), the EPA should conduct an additional ICR if they feel it is necessary to collect additional data on the relationship between PM and non-Hg HAP metals emissions.

Response to Comment 15 - 17: We agree that a reduction in the frequency and types of measurements and monitoring that we proposed is appropriate and will still provide an assurance that sources are maintaining reasonable emissions control of HAP metals and acid gases. First, in response to comments, the final rule has removed all requirements for duplicative testing of a HAP and its surrogate. Facilities complying with a surrogate limit do not have to perform periodic testing for the corresponding HAP, and vice versa. Second, we have changed all requirements for periodic monthly or every other month performance testing to quarterly, with an exception for quarters with very low operating hours. We have clarified that no performance stack testing is required where a CEMS is used for direct compliance, and we have also established an annual performance test requirement for sources that elect to use a PM CPMS as part of the continuous monitoring approach for ensuring compliance with a filterable PM or HAP metals emission limit.

Comment 18: Commenters 18014 and 18498 state that the minimum sampling time of four hours required by section 63.7520(d) for compliance tests is excessive. According to the commenters, the EPA should re-evaluate the required sampling times for each method and/or provide alternative minimum volumes for each method.

Response to Comment 18: We have selected the appropriate test duration that we believe is required to achieve the necessary measurement precision needed to determine compliance. Source testing companies are encouraged to perform an assessment of the ability of an alternative sampling duration, sampling rate and analytical finish which provides for comparable reliable, precise and accurate measurements and that is representative of the sources operation.

Comment 19: Commenter 18018 states that the EPA's proposed compliance requirements are overly burdensome and should be modified due to certain compliance requirements for the proposed air toxic rule that may result in periods of noncompliance by some EGUs that may be capable of complying with the emission limits under normal operations. According to the commenters, the following change would facilitate compliance with the proposed rule: PM compliance testing should involve only filterable particulates. Including soluble particulates will complicate compliance testing without providing significant additional compliance assurance.

Response to Comment 19: The final rule uses filterable PM as the surrogate for non-Hg HAP metals. See further discussion of this issue in the preamble and elsewhere in this document.

5. Other.

Comment 20: Commenter 17902 states the proposed rule definition for a unit designed to burn solid-oil derived fuel and its application is unclear for units that co-fire pet-coke and coal together. The commenter states that the application of Table 1 and Table 2 emission limits needs to be clarified including how emission limits will apply for units that move from one subcategory to another. According to the commenter, the relevant MACT emission limits should be applied based on the majority of fuel actually combusted annually on a heat input basis.

Response to Comment 20: According to the definitions of *coal-fired electric utility steam generating unit* and *oil-fired electric utility steam generating unit* in §63.10042, should an EGU that co-fires pet coke and coal such that more than 10 percent of the annual heat input for 3 years or 15 percent of the annual heat input for one year is from coal, the EGU is a coal-fired electric utility and would be subject to the coal-fired emissions limits.

Comment 21: Commenter 18502 expressed concern that natural sources of atmospheric chlorine in coastal areas that a facility cannot control can cause wide variations in emission rates. The commenter states that these include chloromethane formed by action of sunlight on marine biomass and chlorine from sea foam, possibly influenced by wind direction.

Response to Comment 21: The rule has been revised to address this concern for liquid oil-fired EGUs, such that an owner or operator need not conduct HCl or HF emissions measurement if the owner or operator conducts fuel moisture analysis or provides certification from a fuel supplier and that analysis or certification shows fuel moisture content does not exceed 1 percent.

5C05 - Compliance: Treatment of Common Stacks

Commenters: 15678, 17733, 17739, 17775, 17781, 17796

1. Unit-by-unit control.

Comment 1: Commenter 15678 supports the EPA's application of emission standards to each operating EGU instead of to the overall site consisting of several EGUs. This commenter stated that this approach is especially important for areas with large amounts of impervious land cover where increased stormwater runoff will contribute more land deposited Hg to the food chain via bioaccumulation in seafood. The commenter strongly supports applying the MACT standard to all EGUs.

Response to Comment 1: We have responded to comments relating to emissions averaging across EGUs at a common site in a given subcategory elsewhere in this document.

Comment 2: Commenter 17733 states that in order for the EPA to meet its responsibilities under the Trust Responsibility and the Environmental Justice Doctrine, the EPA should apply the most stringent applicable standard under the EGU MACT Rule to all IB units in a contiguous area and under common control. The commenter states that this approach is necessary to be consistent with the rule's description of a source and helps insure the rule can take advantage of economies of scale by having all IB units at a source apply the same level of control technology. According to the commenter, this approach prevents IB unit owners from avoiding stringent EGU MACT rule requirements by dismantling shared pollution control device exhaust stacks. The commenter states that the EPA should require all IB units as a source to meet the most stringent EGU MACT standard applicable to any EGU at a source.

Response to Comment 2: To the extent commenter is referring to industrial boilers, those comments are outside the scope of this rulemaking and are not addressed. To the extent commenter is referring to EGUs, we have addressed comments related to emissions averaging across EGUs at a common site in a given subcategory and to common stacks elsewhere in this document.

2. Use of combined stack data.

Comment 3: Commenter 17739 states that the EPA's use of combined stack data is inconsistent with its treatment of data below the MDL. The commenter states that in the Boiler MACT, the EPA concluded it was inappropriate to use values below the MDL for the simple and correct reason that "such values have not been demonstrated to have been met" (76 FR 15624) and that the same is true with respect to data from combined stacks; no unit actually "met" the reported value, let alone two. According to the commenter, the data point of the combined emissions is a fiction that represents the combined performance of the suite of control trains and boilers, and there is no basis to know whether one unit would measure higher and the other lower if tested separately, rather than assuming they would both measure exactly the same. The commenter states that in fact, the one result of which we can be absolutely sure is that both units would not produce identical emissions. The commenter states that the EPA's creation of multiple data points from a single combined stack data point are simply a fiction that is not permissible under the MACT standard setting criteria.

Comment 4: Several commenters (12991, 17739, 18023) disagree with the EPA's use of data from multiple units exhausting through a common stack. Commenter 17739 states that the EPA makes two errors: 1) EPA unreasonably treats data from multiple units exhausting through a single stack as multiple data points, and 2) EPA applies this incorrect approach inconsistently. While it may be acceptable for the EPA to surmise that the combined performance of multiple boilers and pollution control devices represents an emissions control strategy that could be a best performer, thereby entitling the agency to use the data at all, the fact is there is only one performer not two. Apart from being inconsistent with applicable MACT case law, commenters assert that counting combined stack emissions as two or more data points is unreasonable because it dampens variability and over represents the emissions data by creating multiple "performers" or sources when there is in fact only one. In the Boiler MACT, the EPA argues its approach of creating two data points from a single combined stack data point is reasonable because it cannot separate the commingled fraction of the emissions from the different emission points. Commenters state that is irrelevant and there is no basis to separate these emissions because the MACT floor is based on best performing sources and there is only a single source. Indeed, the opposite is true. Commenters state that the EPA cannot determine what amount of the overall performance of a combined stack data point is the specific result of the combination. The EPA also argues that applying the emissions equally to multiple units exhausting through a single stack "accurately represents the emissions of those units on average. Commenters assert that is simply not correct and there is no plausible factual basis for that statement. There is no unit that "achieved" those emissions. Rather, the data represent the combined weighted average of two units, without knowing how either unit actually performed.

Commenter states that in the Boiler MACT, the EPA asserts that adding multiple data points for common stack units provided additional data where the EPA's databases are sparsely populated. Commenter states that counting a single stack unit twice to have more data is not necessary in the utility MACT, which is not lacking for data. Commenter also states that counting as two a single stack may dampen variability unlike the EPA's claim in the Boiler MACT. Commenter states that the practice of treating plants that have multiple boilers exhausting through a single stack as if they were separate sources is fairly systemic and results in a widespread population of the database with fictional values.

Commenter 12991 disagrees with the use by the EPA of duplicate records for determining the Hg MACT floor. The commenter states that in several instances when a facility operated tandem or multiple units but only submitted a single stack measurement, the EPA used the single stack measurement to represent Hg emissions from the facility's other stacks. According to the commenter these duplicate records should not have been used because the agency did not systematically select the units; that is, the selection of units was not entirely random nor was it purposefully intended to identify the best-performing units within the total population of units. According to the commenter, the EPA did randomly select some units while intentionally selecting some of the best performing units resulting in a biased selection represented by a greater percentage of baghouse-controlled units than exists in the population of coal-fired utility sources. The commenter states that the duplicate records are redundant and should not be included because they cannot be considered to represent the best performing sources or to be an unbiased or random sample.

Commenter 18023 states that the EPA's MACT floor database lists the four units at Georgia Power Company's Plant Hammond as four separate sources. These units, however, share a common FGD and a common stack. It would be impossible to differentiate the emissions resulting from each unit. This error is not limited to Georgia Power Company's Plant Hammond. This error occurs in 19 of the 130 lowest emitting units for Hg, 25 of the lowest emitting units for PM, and 19 of the lowest emitting units for HCl. The EPA should treat the emission value from units with a common stack as a single source in the MACT floor calculation. Furthermore, the EPA must be consistent in how it treats units with a common stack. Contrary to the manner in which the EPA analyzed Plant Hammond, the EPA has considered at least five multiple-unit, single-stack plants as being a single source (Elmer Smith 1 & 2, Grant Town 1

& 2, Morgantown Energy Facility 1 & 2, Scrubgrass 1 & 2, and Seward 1 & 2). At a minimum, the EPA must be consistent on this point in order to avoid additional methodological error.

Response to Comments 3 - 4: The EPA disagrees with commenters. As in the Industrial Boiler NESHAP, the EPA continues to believe that the emissions from the common stack represent the average emissions of the EGUs exhausting to the common stack and are representative of both EGUs. Commenters have provided no data to support the contention that this assumption is false. In addition, commenters contention that distinct EGUs (i.e., boilers) are one source if they emit out of a common stack is not consistent with the CAA section 112(a)(8) definition, which clearly applies to the individual boiler units with a capacity of more than 25 MW. It would not be reasonable in light of that definition to consider the emissions from two boilers to a common stack as the emissions of one EGU. The EPA used data from combined stacks only where both EGUs were operating or where the owner/operator certified that no air in-leakage could occur. . The EPA expects that companies will comply with the final rule by conducting testing at the common stack as that is usually where the sampling locations are (rather than in the intermediate ductwork) and will report the results as being for each EGU.

The EPA has reviewed the data based on comments received and does not believe that there are any inconsistencies in the data set used for the final rule. In the MACT floor analysis, the EPA used data only from stacks that were tested or for which test data were provided. These stack measurements were not used to represent emissions from other, non-tested, stacks in the MACT analysis.

The ICR required owners or operators to provide the agency with information from individual EGUs, and those owners or operators certified the results submitted to the agency as being true, accurate, and complete. The agency has no ability to and needs not change such submitted data, for if after submission, an owner or operator believed his/her EGU data from a combined stack were inaccurate, he or she could have and should have conducted additional testing to isolate emissions. The agency maintains its use of submitted data for rulemaking purposes remains valid.

3. Common stack provisions.

Comment 5: Several commenters (15678, 17733, 17796) support the approach of applying the most stringent standard to each EGU when they share the same stack and/or controls. Commenters (17733, 17796) add that this should apply when there are similarly fueled units. Commenter 17796 states this would eliminate any possible confusion about the applicable regulatory requirements for both regulators and source owner.

Response to Comment 5: We agree with the commenters and have included such requirements in the final rule.

Comment 6: Commenter 17775 states that the EPA's proposed common stack provisions fail to provide sufficient flexibility for EGUs with different control technologies that vent to a common stack. The commenter states that under proposed section 63.10009(h)(i), two or more units that vent through "a common control system" to a common stack may be treated as a single unit, and some units with one common control (e.g., an FGD) may not share other controls (e.g., SCR). The commenter asserts that although such units may be able to meet the proposed emission limit at the common stack during normal operation, any significant outage at one unit could make compliance on a 30-day rolling average basis impossible. The commenter states that the EPA addressed the issue of outages for single stack units participating in averaging plans under section 63.10009(b) by providing a 12-month rolling average compliance period and should provide the same for common stack units that use averaging to comply.

Response to Comment 6: We have addressed common stack issues elsewhere in this document. We continue to believe that the emissions of the common stack represent those of all of the EGUs ducting through that common stack. Should this present problems for the owner/operator, they are free to conduct their compliance or CEMS testing in the ductwork prior to the common stack so as to measure emissions from the individual EGUs.

Comment 7: Commenter 17781 states as currently written, paragraphs (h), (i) and (j) do not seem to address the likely situation where each of the EGUs associated with a common stack are affected units within the same category, but they do not utilize common control devices (i.e., each EGU is equipped with its own control device(s)). The commenter states that if the EPA is concerned about a possible conflict in testing frequency in cases where different control technologies are employed by EGUs sharing the common stack, the EPA could stipulate that the testing frequency for the common exhaust stack is based upon the most frequent testing schedule for any of the individual units sharing the common stack based upon the individual EGU control technologies and common stack compliance method.

Response to Comment 7: The final rule includes simplified testing frequency requirements and there may be fewer situations of multiple and different testing frequencies applying to units sharing a common stack. We agree with the commenter that in any case the more frequent testing requirement must apply to testing for that common stack.

5C06 - Compliance: Startup, Shutdown, and Malfunction

Commenters: 15678, 16849, 17174, 17197, 17283, 17316, 17383, 17386, 17402, 17622, 17623, 17627, 17637, 17638, 17648, 17675, 17677, 17689, 17691, 17702, 17704, 17705, 17712, 17714, 17715, 17716, 17720, 17722, 17724, 17725, 17728, 17729, 17730, 17732, 17736, 17737, 17740, 17752, 17755, 17756, 17757, 17758, 17761, 17767, 17772, 17774, 17775, 17776, 17795, 17796, 17801, 17807, 17808, 17813, 17815, 17816, 17820, 17821, 17851, 17856, 17868, 17870, 17876, 17877, 17878, 17880, 17881, 17885, 17886, 17902, 17904, 17909, 17912, 17923, 17925, 17928, 17930, 17975, 18014, 18018, 18021, 18025, 18034, 18037, 18428, 18429, 18447, 18449, 18450, 18498, 18500, 18539, 19032, 19040, 19114, 19120, 19121, 19122, 19536, 19537, 19538, 18023

1. Emission standard applicability during SSM.

a. Support or oppose SSM approach.

Comment 1: Commenters (15678, 17880) support the EPA's approach that emissions standards apply at all times. Commenter 17648 states that the EPA proposed reasonable and appropriate emission limitations applicable to SSM periods, and cites the *Sierra Club* decision. Commenter 19536/19537/19538 states that sources must comply with emission standards at all times, including startup, shutdown and malfunctions. *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008). Commenter 18450 supports that emission limits include startup and shutdown, since these emissions are readily quantifiable.

Comment 2: Commenter 17851 states that the EPA's requirement to meet steady-state standards during SSM events is not logical and is not lawful. Commenter 17851 states that from a physical and legal standpoint, it makes no sense to group SSM and normal operation events under the same set of standards. Commenters (17740, 17772, 17821, 17868) state that including SSM in the standard is unreasonable.

Commenter 17772 states that the CAA unambiguously requires that the EPA look to the actual performance of actual units including performance during periods of start-up, shut-downs, malfunctions. Instead, the EPA started with very limited data from EGUs operating under ideal conditions- generally three hours of operation at full load. As a result, the data were skewed towards a performance level that none of the EGU's from which data were collected can "achieve in practice." Each of those EGU's, and every other EGU in the country, has start-ups, shut-downs and malfunctions where emissions will be substantially higher than the performance that can be achieved under full load and ideal operating conditions.

Commenter 17868 states that the test operations and statistical treatment of the test data do not represent periods of startup, shutdown, or malfunction. Therefore those periods of operation should not be subject to the standards. A work practice approach, similar to that promulgated for industrial boiler HAPs, would be appropriate for these abnormal operating periods. Second, the continuous compliance assurance requirements – which include enforceable limits on various fuel and hardware variables like the pressure drop across a control device – are effectively more stringent than the emission standards that they support, and therefore were not "achieved in practice" by the best controlled units.

Comment 3: Multiple commenters cite concerns about how the rule addresses SSM emissions and made statements such as the following regarding SSM:

- MACT standards are too stringent (17383, 17623, 17689, 17712, 17740, 17761, 17772, 17774, 17813, 17816, 17877, 17885,)
- Emission limits are too low for coal- and lignite-fired units to meet and still remain economically operational (17930)
- SSM makes the standard more stringent (17730, 17868, 17902)
- SSM is a significant burden (17774, 18447)
- Concerned that the emission limits apply at all times, including SSM periods (17197, 17675, 17725, 17728, 17729, 17732, 17736, 17737, 17756, 17758, 17761, 17774, 17775, 17808, 17815, 17870, 17886, 17904, 17912, 17928, 17930, 17975, 18037, 0234-19536/19537/19538, 0234-18023)
- State limits should not apply during SSM periods (17383, 17704, 17712, 17724, 17720, 17725, 17730, 17736, 17752, 17774, 17813, 17820, 17868, 17876, 17885, 17904, 17909, 17925, 18014, 18429, 18498, 19032, 19120)
- SSM data should not be included in the 30-day average (16849, 17627, 17767, 17772, 17774, 17904, 18428, 19120)
- Including SSM could result in exceedances of the 30-day standard or noncompliance (17730, 17868, 17930)
- Requests an exemption during SSM periods (17637, 17820, 18498).

Comment 4: Commenter 17930 states that the EPA has a long history of exempting SSM periods from NSPS and NESHAP, and this should continue. Commenter 19121 states that startup and shutdown emissions have historically been exempt. Commenter 17851 states that before the *Sierra Club v. EPA* decision, the D.C. Circuit consistently held that technology-based standards must contain exemption or less stringent standards during SSM than would apply during steady state periods, and cites several court cases regarding the EPA's previous treatment of SSM events, including, *Portland Cement Ass'n v. Ruckelshaus* (1973), *Essex Chem. Corp. v. Ruckelshaus* (1973), *NRDC v. EPA* (1988), *Marathon Oil v. EPA* (1977), and *National Lime Ass'n v. EPA* (1980). Commenter 17851 states that now that the court decided that MACT standards must apply during SSM, the EPA must develop standards that are "achievable" during those events.

Comment 5: Commenter 17856 sees many compliance and enforcement issues arising from the startup and shutdown provisions. Commenter suggests the EPA adopt reasonable startup and shutdown provisions.

Comment 6: Commenter 17868 provides an example calculation and a graph showing the hours of SSM it would take to exceed the 30-day standard as a function of normal emission rate, given various SSM emission rates in lb/MMBtu. In the example calculation, commenter 17868 states that if the normal emission rate is 0.02 lb/MMBtu and the startup emission rate is 0.45 lb/MMBtu, then a unit could have only 16.7 hours in startup before exceeding the standard. Commenter 17868 states in another example, that for a normal emission rate of 0.28 lb/MMBtu PM and a startup emission rate of 0.45 lb/MMBtu, then the unit could have only 3.4 hours before exceeding the standard.

Commenter 17867 states that unlike the Industrial Boiler MACT, which requires work practice standards be met during periods of startup and shutdown, the Utility NESHAPs Rule requires numerical emission limits. The EPA asserts that startup and shutdowns are predictable and routine aspects of source operations; thus, a 30-day averaging period should be sufficient to smooth any startup and shutdown emissions. The commenter disagrees with this assertion. Startups and shutdowns are not always routine and a 30-day averaging period will not always be enough to smooth out the emission averages. The EPA has not provided justification as to why the work practice standards, as allowed under CAA 112(h), should not apply during periods of startup and shutdown. The commenter recommends that the EPA should adopt work practice standards during periods of startup and shutdown for sources subject to the rule.

Response to Comments 1 - 6: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

b. Economic.

Comment 7: Commenter 17772 states that the capital cost of compliance is related to how startup/shutdown periods are handled and the filterable PM limit, in that including startup/shutdown emissions in 30-day rolling averages may force companies to install additional multimillion dollar controls that may not otherwise have been necessary. Commenters (17815, 17904) state that installing additional APCDs to target startup/shutdown emissions does not make economic sense considering the startup/shutdown time and the amount of emissions contributed to overall EGU emissions.

Response to Comment 7: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion.

c. No APCD experience.

Comment 8: Commenter 18498 states that facilities have no experience with the APCD and additives necessary to comply with the standards, and facilities cannot predict what emissions may occur during startup/shutdown or how compliance can be achieved during those periods. Commenter 17912 fails to understand how a new or reconstructed facility can design, build, or operate APCD that must meet a standard at all times, including SSM periods, when the facility has no way of knowing through any scientific means or method what the "compliance standard" for continuous compliance will be until the equipment is first tested. Accordingly, the commenter requests that the agency remove this requirement and replace it with a number derived from the ICR data base with a reasonable allowance added for the operational flexibility needed to assure compliance under the "worst foreseeable circumstances."

Response to Comment 8: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

d. Not able to achieve the standard.

Comment 9: Multiple commenters (17383, 17689, 17712, 17740, 17813, 17876, 17885, 17930, 19032) state that applying MACT limits during startup/shutdown places the source at risk of noncompliance. Commenter 17775 states that limited data from startup and shutdown events show these events can cause significant compliance concerns. Commenters (17774, 17877) state that the EPA has no factual basis to conclude that even the best performing sources can achieve the standards. Commenter 17736 states that the EPA's flawed assumptions are devastating in that some of the most technologically advanced units (controlled with overfire air; SCR; FGD; and FGD plus SCR) will not be able to achieve the MACT limits during SSM periods. Commenter 17795 states that some units may be forced to operation at economic loss for no reason other than to generate enough full load operating data to comply, and potentially displacing units that have fewer emissions.

- Commenters (17736, 19122) state that just a few hours of noncompliance during SSM can destroy/exceed the 30-day rolling average.
- Commenter 17925 states that several startups can occur in a 30-day period and cause noncompliance.
- Commenters (17383, 17689, 17712, 17724, 17813, 17876, 17885) note that more than one outage could mean noncompliance.
- Commenter 17868 states that one outage could cause an exceedance.
- Commenter 19032 states that outages could put a unit in noncompliance.
- Commenter 17868 states that forced outages are out of the utility's control.
- Commenters 17756, 17775, 17820 state that units with more than one SS will be penalized with significantly higher emissions and also a smaller number of operating hours.
- Commenter 17767 states that if a unit that experiences a difficult, lengthy startup, compliance with the 30-day averages would be difficult or unachievable.

Response to Comment 9: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

e. 30-day average not sufficient.

Comment 10: Commenter 17904 believes the EPA has taken a positive step in establishing a 30-day average. Commenter 19121 generally supports the 30-day average, if non-Hg HAP are to be regulated.

Comment 11: Commenter 17877 states the 30-day averaging period is not sufficient to allow compliance. Commenter 16849 states the 30-day average period is too short. Commenters (17807, 17886, 17925) state that the EPA has not demonstrated the 30-day averaging period will enable compliance. Commenter 17740 states that varying operating modes experienced by EGUs make a 30-day averaging period impractical or impossible. Commenter 17930 states that 30-day average is not sufficient to account for the variability of lignite.

Comment 12: Several commenters (17775, 17795, 17877, 17925) state that a 30-day averaging period is not sufficient to account for startup/shutdown emissions. More specifically:

- Commenter 17877 states that 30-day average is not sufficient where multiple SS occur.
- Commenter 18428 states 30-day average is not sufficient to account for varying load conditions and SS.
- Commenter 17728 states the EPA cannot assume that a longer averaging period accounts for startup/shutdown, and the EPA provides no data to support the assumption.
- Commenter 17740 states that examination of EGU operations demonstrates that a 30-day average is insufficient to account for variable emissions from multiple startups and shutdowns.
- Commenter 16849 states that every SSM produces emissions that will be problematic for the averaging period.

Comment 13: Commenter 17740 states that EPA's statement that EGUs "do not normally startup and shutdown frequently" effectively, and incorrectly, assumes that all units are operated as base load units. As the Seventh Circuit recognized in *United States v. Cinergy*, "[u]tilities operate power generation equipment in three general ways: base load, cycling, and peaking." 623 F.3d 455, 459 (7th Cir. 2010). Non-base-load units start up and shut down frequently, and even supposed "baseload units" are often, and unpredictably, shut down for unit “trips” (i.e. unplanned outages). The EPA further assumes that basing the proposed standards on a 30-day rolling average will account for any increased emissions during periods of startup and shutdown. The EPA made this same faulty assumption in the proposed rule that preceded the Boiler MACT (see 75 FR 32,012-13) and rejected it in the final rule (see 76 FR 15,642). The EPA has not demonstrated that the 30-day rolling average will address the substantial operating variations among EGUs or even within an EGU. Further, while a number of the MACT pool EGUs are newer, well-controlled, base load units, the EPA cannot assume that the entire universe of coal-fired EGUs, even base-loaded units, will operate as reliably as newer units. As EGUs age, they tend to experience more forced outages than when they were newly constructed. Thus, an older EGU with highly efficient controls may not be able to meet a 30-day standard in months in which it experiences a number of forced outages.

Response to Comments 10-13: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA’s rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

f. Normal plant operations/outages/describe SSM periods.

Comment 14: Commenter 16849 states that SSM are part of power plant operations and facilities should not be penalized for these occurrences. Further, commenter asserts that providing no exemption during startup/shutdown is an unrealistic expectation. Commenters (17878, 19114) state that SS(M) are part of normal operation. Commenter 17737 states the EPA should consider startups part of normal operation. Commenter 17772 states that even top performers will have occasional malfunctions and will have multiple startup/shutdown periods during a year.

Commenter 17740 states that the EPA ignores the fact that EGUs require an extended period of startup during which equipment (boiler, control devices) are not operating in their normal conditions, and this extended period cannot be shortened or avoided. Commenter 17737 states that several factors can lead to multiple startups or long periods of startup, including equipment problems (burner management logic, ignitors), or problems related to water chemistry, that would prolong the unit getting to temperature. Commenter 17737 notes that when outage does occur, there may be multiple or long startup attempts that are more relevant in terms of the EPAs compliance standard based on 30 boiler operating days. Commenter 17737 provided a list of startups and corresponding bypass times allowed in their Title V permit in 2010.

Commenter 17795 states that their units startup and shutdown frequently, and note it is not uncommon for units to have more than four startups in a 30-boiler day operating period. Commenter 17795 provides a table showing the number of startups during the first 30 days of 2010 for several typical units: unit 1 had 12 startups; unit 2 had 5 startups; unit 3 had 20 startups; unit 4 had 7 startups; and unit 5 had 4 startups.

Commenter 16849 states that cold startup can take 16 hours, and two or three startups in a month will not allow the facility to meet the SO_2 surrogate standard. Commenter 18498 states that the time for startup depends on the type of startup (cold, warm, hot). Commenter 17740 notes that startup duration varies depending on the condition of the boiler at the time of startup, i.e., cold starts can take approximately 72 hours, warm starts up to 18 to 20 hours, and hot starts can take 6 to 8 hours.

Commenter 18025 states the majority of APCDs require a period of time to reach peak performance (temperature and flows). Commenter 18498 states that adequate time is needed for APCD to operate prior to measurement of filterable PM.

Commenter 17774 states that many units have multiple startup/shutdown events within 30-day period due to varying load demand or maintenance, and outages that may or may not meet the criteria of malfunction. Commenter 17740 states it is not uncommon for their plant and other similar units to experience more than one startup within 30 days due to forced outages and planned maintenance. Commenter 17316 states that the averaging period is only appropriate if the number of startups is small and the duration is normal. Commenter 17877 states it is unreasonable to assume a large EGU will only SS once during a 30-day period.

Commenters (16849, 17923) describe the EGU forced outage rate curve throughout its life cycle as an inverse bell curve: high forced outage rate when new until issues are resolved, reduced forced outage period until parts reach their useful life, then increased forced outage rates again as parts must be replaced.

Response to Comment 14: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

g. Peaking units.

Comment 15: Several commenters (17725, 17820, 18014, 18498) state that even with relatively long averaging periods (30-day rolling averages), the emissions from nonrepresentative periods could significantly affect averages, especially for peaking units or other units that come online and offline frequently. Commenters (17715, 17757, 19114) state that including startup/shutdown periods have a great effect on peaking units that startup and shutdown more. Commenter 17736 states the EPA failed to account for the critical operation of peaking units which go through these periods frequently. Commenters (17316, 17386) state that the averaging period will not work for EGUs (e.g., dispatchable) that are in service for short periods (e.g., part of a day) and startup/shutdown periods represents a significant portion of the operating day.

Commenter 17820 states that units that are required to follow load demand will be penalized. Commenter 17774 states that the EPA does not account for load-following units or units used on a sporadic basis. Commenter 17774 states that a number of their units follow load, cycle, or are otherwise subject to numerous startup/shutdown periods. Commenter 17623 states the EPA's analysis is flawed because it did not account for load following or load cycling facilities, which startup and shutdown on a more frequent basis and have additional SSM periods.

Commenter 17720 states that use of 30-day averaging period will not smooth out any emission increases associated with startups/shutdowns that are driven by dispatch decisions by distant RTOs. Commenter 17772 states that many EGUs are RTO members and must follow RTO directives to shutdown or run at minimum loads.

Comment 16: Commenter 17930 agrees generally that coal-fired baseload units do not SS often, however this is likely to be less of the norm. Commenter 17704 agrees that base load units do not typically startup and shutdown frequently, however, that is changing and cite a new nodal system in Texas that may increase the frequency of startup/shutdown events. Commenter 17795 states that recent regulation changes, Cross State Air Pollution Rule (CSAPR), could cause units to cycle more in the future placing greater emphasis on potential effect on SSM on average emissions.

Comment 17: Several commenters (17720, 17758, 16849, 17930) discuss the use of renewable fuels. Commenter 17720 notes that the EPA's assumption that startup/shutdown periods are predictable and routine does not take into account the increasing impact of renewable resources and the increasing control of RTOs. Commenters (17758, 16849, 17930) note that the use of renewable fuels will cause additional startups/shutdowns for fossil-fuel units. Commenter 17758 states while routine maintenance and repair and transmission upgrades are predictable and routine, the increased cycling (unplanned outages) to accommodate renewables results in increased startups and shutdowns. Commenters (17758, 16849) note that the overall impact of cycling reduces overall emissions because fossil units are used less and renewables are used more. Commenter 17758 states the small emission increase during startup/shutdown periods is likely dwarfed by avoided emissions due to renewable facility operation. Commenters (17758, 16849) state the EPA should not penalize environmentally friendly practices. Commenter 17758 states the emission benefits associated with increase operation of renewable resources exceed those realized by imposing numeric standards during startup/shutdown periods. Commenter 17868 states that including SSM activities are a concern because of the increasing number of "load-following coal-fired power plants that backup wind and solar power plants. Further, commenter 17868 states that ramping up and down and the startup/shutdown activities will increase emissions.

Comment 18: Commenter 17796 states that EPA should allow an emission calculation based on an emission factor for SSM, and suggested a simple calculation based on fuel feed rate multiplied by a predetermined emission factor will give an accurate measurement of emissions, rather than the onerous requirement to monitor fuel flow rates and sample fuel to determine heat content and composition.

Response to Comments 15 - 18: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

h. Monitoring plan/suggested startup/shutdown approaches.

Comment 19: Commenter 17316 recommends that facilities establish a maximum allowed duration for startup/shutdown periods in the Monitoring Plan. Commenters (17316, 17386) state if startup/shutdown hours exceed a certain proportion of total operating hours in the 30-day operating period (e.g., more than 20 percent), then startup/shutdown periods should be excluded from the 30-day average.

Response to Comment 19: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion.

i. Not clear how SSM included/no basis for standard.

i. General.

Comment 20: Multiple commenters indicate that data used for the MACT floors are not representative of startup/shutdown conditions, and provided various comments including:

- MACT floor or limit does not account for SS(M) emissions (17623, 17715, 17725, 17757, 17774, 17820, 17851, 17868, 17877, 18014, 18037, 18429, 18498, 19114, 19121, 0234-18023)

- EPA does not account for required shutdowns (17761)
- EPA does not have emissions data for startups/shutdowns for EGUs (17732, 17756, 17851)
- EPA never collected and analyzed a sufficient amount of data (17736)
- Facility does not have startup or shutdown emission data (17722, 17737)
- EPA does not have sufficient information or data on SS(M) emissions (17795, 17736, 17402)
- Data was during regular operation (17732)
- Application of the MACT standards during SSM periods is inappropriate (17623, 17774, 18037)
- EPA has not accounted for emissions, or higher emission levels, from SS (17730, 17736, 17761, 17772, 17816, 17821)
- EPA cannot apply a single standard that applies at all times (17732, 17774)
- Commenter 18429 states it is inappropriate to include SSM in the compliance demonstration

Commenter 17740 states that the EPA fails to consider whether performance standards would be practicable at EGUs during startup/shutdown periods. Commenter 17722 questions whether the EPA has correctly evaluated startup/shutdown periods in setting the limits. In addition:

- Commenters (17197, 17627, 17704, 17715, 17716, 17722, 17724, 17725, 17728, 17730, 17732. 17736, 17752, 17757, 17761, 17767, 17774, 17775, 17808, 17820,17870, 17876, 17877, 17878, 17886, 17904, 18014, 18037, 18428, 18498, 19114, 18023) state that stack testing data submitted (under the ICR) did not include SSM periods but was for normal, steady-state operation. Commenter 17851 states that all data was collected under steady-state conditions. Commenter 17736 states the MACT limits are based on full load steady state testing, and not on the full range of operating conditions, including changes in operating variables. Commenter 17736 states that data that is limited to a single operating characteristic under utopian conditions is insufficient and inappropriate for establishing MACT limits that must be satisfied at all times.
- Commenter 17767 states that no attempt was made to quantify emissions from startups/shutdowns during development of the emission limits. Commenter 17925 states no stack test data exists for startups/shutdown.
- Commenters 17772, 17774, 18428 state EPA analyzed short-term testing (snapshot) of EGUs under normal operation conditions. Commenter 19114 states it is impossible to declare the MACT floor includes variability adjustments for SS when EPA possesses no test data to support the declaration. Commenter 17761 states the rules fail to account for operational variability and required shutdowns and do not appropriately represent emissions that can be consistently achieved.
- Commenter 17925 assumes EPA used isokinetic stack testing during normal operation, without regard to actual emissions limit, or used arbitrary non-isokinetic assumptions to quantify SS emissions.
- Commenter 17925 does not understand how the EPA integrated startup/shutdown emissions into the 30-day standard.
- Commenter 17774 notes in particular that no malfunction data was incorporated into the MACT floor.

Commenter 17736 states that EPA should recognize these issues, especially when establishing standards without adequate consideration of data and other information.

Commenters (17383, 17724, 17876) question whether the EPA has accurate startup data for Hg emissions, state they are not aware of any Hg startup emission data, and note that Hg emissions spike during startup. Commenters (17383, 17724, 17876) request that the EPA provide a clear analysis of this startup Hg emissions data with respect to the development of the variability calculations and the standard.

Response to Comment 20: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

ii. The EPA not demonstrated that limits are achievable.

Comment 21: Commenter 19114 states that by setting a limit to include startups/shutdowns but basing the limits solely on full load, steady-state test data, the EPA is violating the requirements of the CAA to set achievable standards. Commenter 17772 notes that the EPA's approach understates the true average emissions of top 12 percent. Commenter 17878 states that the emission standard is lower than the rate "achieved in practice" by the best performing units. Commenter 17761 states that the EPA inappropriately established standards that do not reflect the "average emission limitation" achieved by the best performing 12 percent of existing sources. Commenters (17724, 17876) state the EPA must evaluate startup/shutdown emissions to demonstrate that the limits are achievable. Commenters (17402, 18037, 18539) state that given the lack of data and that the limited data that are available show emissions are higher during SS, the EPA has not established an emission standard that can actually be achieved during SSM, as required by statute. Commenters (17851, 17878) state that MACT standards must be based on evidence that sources have achieved them. Commenter 17851 states that standards must be achievable under the most adverse circumstances which can reasonably be expected to recur.

Comment 22: Commenter 17732 states the EPA should explain what data was used to come to the conclusion that a single standard can be met at all times, including startup/shutdown periods. Commenter 17737 states that EPA provides no data or analysis to demonstrate that coal-fired EGUs will be able to meet the standard including SS periods. Commenter 17851 states the EPA must demonstrate why facilities can comply with the final standards. Commenter 17851 states that the EPA's statement that sources can meet the standard during SSM is not based on any data, at least there is not data in the record. Commenter 17724 states the EPA must evaluate the ICR data to identify startup/shutdown emissions. Commenter 17722 requests that the EPA demonstrate how the ICR data is inclusive of startup/shutdown emissions for each regulated pollutant. Commenter 17772 states the EPA failed to quantify the level of any startup/shutdown adjustment, explain its methodology for taking SSM into account, and has not used real data for an adjustment, and thus the emission limits are arbitrary and capricious. Commenter 17815 states it is unclear how much SSM data was included in the analysis.

Comment 23: Commenter 18023 states that the impact of a single startup or shutdown event is unknown. Commenter 18428 states that representations by the EPA and other stakeholders that a number of units already meet the proposed limit are based on stack test data and not on continuous monitoring over 30-day periods, so these representations are incomplete at best. Commenter 18023 states that the EPA has not shown through analysis that startup and shutdown events will not have a significant impact on the 30-day averages and the EPA has not presented evidence that they accounted for the impact of startups/shutdowns as it claims, given that the stack test data the emission limit is based on was collected for full-load steady state conditions. Commenter 17795 states that meeting a standard based on steady state operations at full load during SSM and load swings by use of a 30 day averaging period is not supported by data. Commenter 17758 states the EPA has not demonstrated that the 30-day average will enable compliance, and the EPA's assumption is unsupported by data from actual units. Commenters (17728, 17729, 17775, 17756) state the EPA has no way of knowing if the 30-day average is sufficient to address unpredictable startup emissions. If the EPA cannot demonstrate, then commenters (17724, 17876, 19032) state that startup/shutdown periods should be excluded from 30-day averages.

Response to Comments 21 - 23: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

iii. Burner inspection outage.

Comment 24: Commenter 17761 states that at a minimum, with the mandatory burner inspection requirements that impose an additional startup and shutdown on facilities, the EPA should take into account the emissions from the mandatory startup and shutdown precipitated by its own rule in establishing the "best performing" sources. Commenter 17930 states that rule requirements for annual shutdowns, for burner tune-ups, will increase the frequency of baseload units being shutdown, along with the suit of other EPA regulations. Commenter 17930 cites the allowance allocations in the CSAPR that assume units will operate seasonally, which will result in more SSM activity.

Response to Comment 24: In addition to the final rule treatment of startup and shutdown periods discussed in the responses under this section (see Responses to Comments 1-23, above), EPA also notes that the final rule adjusts the frequency of burner inspections to once at least every 36 months (or 48, in certain circumstances), so that the inspections can better coincide with planned unit outages. See further discussion under section 4D02 of this document.

iv. Burner inspection requirement.

Comment 25: Several commenters (19536, 19537, 19538) state that during SSM events, organic HAP emissions are known to increase for short periods due to low boiler combustion temperatures, poor mixing, and low excess oxygen levels. Commenters state that the proposal is silent as to how an annual tuneup would assure organic HAP emissions remain controlled during SSM periods.

Response to Comment 25: Under the general provisions of Part 63, all sources must operate and maintain their sources in accordance with good air pollution control practices to minimize emissions. Those general provisions, together with the standards that apply (including the specific work practice standards in the final rule applicable to startup and shutdown periods), will ensure that organic HAP emissions are minimized from affected sources during SSM periods.

v. Recommendations for EPA.

Comment 26: Commenter 17622 recommends re-testing of units under the same conditions to verify emissions are repeatable and sustainable over operating periods that include startup/shutdown periods. Commenters (17732, 17772, 17774, 17877) state the EPA should collect and analyze data for emission standards during SS(M). Commenter 17737 states EPA should collect and analyze emissions data to evaluate the compliance risk associated with inclusion of startup periods in the MACT standard for normal operations. Commenters (17815, 17904) state that the EPA should analyze excess emission reports to determine the frequency of startups/shutdowns and include that analysis in the standards.

Commenter 17795 states the EPA must account for the effect of startup/shutdown emission on a 30-day average. Commenter 17729 states that setting the PM limit as the actual emission value measured during steady-state testing leaves no room for process variability and for startup/shutdown emissions.

Commenter 18021 believes the EPA needs to consider applying adjustments to the limits to allow for differences in operation conditions. Commenter 17930 states the EPA should increase the emissions limits for all pollutants to better account for SSM emissions. Commenter 17912 requests that the EPA replace the requirement with a number derived from the ICR database with a reasonable allowance added for operational flexibility needed to assure compliance under the worst foreseeable circumstances.

Response to Comment 26: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. This approach is more workable than the use of adjustments as suggested in some of these comments. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

vi. Variability component.

Comment 27: Several commenters (17725, 17820, 18014, 18037, 18498, 18539) state that the EPA does not have sufficient data (either reference method or CEMS data) to address variability during SS(M) periods and load changes (17820). Commenters 17730 and 17761 state startup/shutdown emissions must be adequately accounted for in the variability component. Commenter 17886 states the EPA should revise its variability adjustment to account for long term unit emissions variability. Commenters 17724 and 17876 state that the variability component of the MACT floor calculation drives the final emission limit more so than the mean value of the data set. Commenters 17724 and 17876 further state that the variability component could be drastically different with inclusion of startup/shutdown emissions data, resulting in a higher limit. Commenter 17722 states the EPA would develop a much different emission limit if startup/shutdown emissions were in the data sets.

Response to Comment 27: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

j. SSM results in increased emissions/distinct operating modes.

Comment 28: Commenters 17730 and 17740 state SS(M) periods are distinctly different modes of operations from normal operation. Commenters 17705 and 17757 state that startup/shutdown periods have different emission characteristics than emissions during normal operations. Commenters 17715 and 19114 state that startup/shutdown emissions are not similar to steady state full load emissions. Commenter 17878 states that SSM periods result in increased emissions rates. Several commenters (17715, 17757, 17856, 19114) state increased emissions during startups/shutdowns could skew the average emission rate. Commenter 17851 states that non-steady state emissions could alter the EPA's calculations. Commenter 17705 states that other transient conditions such as significant load changes will result in emissions in excess of those measured during initial performance tests. Commenter 17851 states that emissions during non-steady state conditions may vary significantly.

Several commenters (17808, 17870, 18025) note that, as in the Boiler MACT, malfunctions should not be considered a distinct operating mode. Commenter 17851 disagrees with the EPA that malfunctions are not distinct operating modes.

Commenter 18023 states that startup is a distinct operating period and it should be considered independently. Commenter 18023 provides Hg CEMS data showing two distinct emission profiles for periods of startup (when SCR is offline due to low temperature) and for periods of steady-state with full control (when both SCR and FGD APCD systems are operating). Commenter 18023 further states that steady-state emissions data do not represent emissions during startup/shutdown periods.

Commenter 17775 states that long-term Hg and PM CEMS data show spikes in emissions that are likely due to startup/shutdown events. Commenter 18428 has reviewed Hg CEMS data from 2 coal-fired units and states that the data spike above the proposed standard (1.2 lb/trillion Btu) is likely due to fluctuations.

Commenter 18449 states that startup results in very high stack Hg concentration for a short amount of time, most likely from Hg deposited on ducts and other surfaces, although Hg emissions are not necessarily high since the flow rate is very low. Commenter 18449 provides graphs with actual startup Hg emissions from Hg CEMS; the normal emissions are 3 to 4 ug/m3, with an ESP and SCR. Commenter 18449 states that the short transient nature of SSM events causes severe errors in estimating hourly mass emissions based on multiplying hourly averages of pollutant concentration and hourly average of stack flow; these problems are worse when the mass is normalized to lb/GWhr using a 5 percent of full power output, which will artificially inflate the emissions rate by a factor of 20 and added to the rolling average, even though the actual mass emissions may not be significant during SSM. Commenter 18449 states this is punitive.

Commenter 17772 states that their facility has 18 months of PM CEMS data with startups/shutdowns included that shows fully controlled units will not be able to comply with the emissions limit. The commenter provides graphs of 30-day boiler operating day average data for three units, and provided data showing the wide difference between PM CEMS data with and without startup/shutdown data. (See Figures 1 through 3 and Table 3 of letter, Docket Item No. The EPA-HQ-OAR-2009-0234-17772.) The commenter indicates that 0.018 lb/MMBtu is representative value for filterable PM, however, with startup/shutdown values included, the representative value is 0.29 lb/MMBtu (includes low flow rates, high concentrations, and CO_2 diluent of 5 percent), which is 16 times higher.

Commenter 17795 provides average SO_2 emissions data for 30 boiler operating days that include two startups, showing that SSM occurred for 10 percent of operating hours during the period and that including SSM emissions results in an increase of 13 percent in the 30-day average emission rate.

Response to Comment 28: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. In addition, one commenter maintains that the during SS and M periods there are fluctuations in the monitoring, but the commenter also refers to a provision in the proposed rule that allowed sources to assume a 5 percent of full capacity factor for periods of startup and shutdown. The 5 percent conversion is no longer included in the rule because we are establishing work practice standards for such periods. Because the proposed 5 percent factor does not apply to malfunction periods, the comment concerning artificial inflation of the emissions rate is not relevant to periods of malfunction. The final rule requires source owners who use continuous monitoring to measure emissions during malfunctions periods. We believe that it is important to collect data during all process operating periods including SSM periods, as the rule requires when conducting any continuous monitoring (see additional responses below relative to the accuracy and utility of such data). The agency also believes EGU owners or operators strive to minimize periods of malfunction and should a malfunction period occur, its duration will be brief, as noted by the commenter. Any impact of potential excess emissions occurring during a period of malfunction should be offset to some degree through use of the rule's 30 boiler operating day rolling average requirement. To the extent the CEMS records an exceedance during a malfunction, and the owner or operator believes the measurement was in error, the owner or operator can demonstrate that the source complied with the standard notwithstanding the CEMS measurement using any available information. See also responses below that address the issue of determining compliance during malfunction events.

k. Use of CEMS during startup/shutdown.

Comment 29: Several commenters express concerns regarding the use of CEMS for measurement during startup/shutdown. Commenters (17677, 17728, 17729, 17775) also indicate it is not feasible to measure compliance with CEMS during startup; commenters cited the following issues for startup/shutdown, including temperature issues (17728, 17729, 17815), low flow rate (17815, 17728), and varying moisture (17729). Commenter 18498 states that particulate size varies during startup/shutdown and cannot be measured accurately by PM CEMS. Commenter 18498 states that startup/shutdown periods present wide variations depending on the process and control equipment. Commenter 17728 states the EPA does not account for the absence of correlated PM CEMS during startup/shutdown periods. Commenters (17728, 17736, 17752, 17772) state the PM CEMS correlation curves do not include any data during SSM periods. Commenters (17728, 17752) state the PM CEMS cannot be correlated and the accuracy of PM CEMS data during those conditions is unknown, and commenter 17736 states the correlation can only be done during normal operating loads. Commenter 18498 states that PM CEMS are calibrated for normal operating conditions. Commenter 18498 states that startups/shutdowns present significantly different conditions that are not part of PM CEMS calibration.

Commenters 17677 and 17775 state that CEMS are not correlated to startup/shutdown periods because the EPA reference test methods were not designed for transient or dynamic plant operations. Commenter 17677 questions the enforceable value of these data, and states the EPA needs to consider the ability for CEMS to accurately monitor emissions in startup/shutdown periods. Commenter 17772 states the PM CEMS data from startups/shutdowns are not reliable and highly variable. Commenter 17886 states they do not know of valid test or CEMS measurement techniques for HAP during startups/shutdowns. Commenter 17736 states that most units do not start up on coal but use other fuels (e.g., fuel oil), and a PM CEMS that was correlated for coal does not measure emissions accurately. Several commenters (17725, 18014, 18498) state that particle size distribution or unburned levels during startup affect PM CEMS measurement accuracy, particularly those using light scattering or optically-based technologies; commenter 17728 states that the particle size distribution may differ from those in the correlation.

Several commenters (17725, 17820, 18014, 18498) state that including SSM is critical for units using PM CEMS to demonstrate continuous compliance, since part 63 no longer includes exemptions for SSM.

Commenter 17925 states that there are very few CEMS in operation to provide data to confirm that limits can be met during startup/shutdown.

Commenters 17774 and 17821 relay that there are operation problems for sorbent trap CEMS to demonstrate compliance with Hg limits during startup; Commenter 17774 cites the following for sorbent trap CEMs: demonstrate poor performance, flue gas conditions are unacceptable, and interferences cause breakthrough.

Response to Comment 29: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits and thus commenters concerns related to reliance on CEMS during such periods is moot. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

With respect to commenters' concern that PM CEMS cannot be correlated and the accuracy of PM CEMS data during malfunction periods is unknown, see responses below that address the issue of determining compliance during malfunction events.

l. The EPA assumptions/justifications.

i. Support or oppose EPA's assumptions.

Comment 30: Multiple commenters (17728, 17740, 17758, 17774, 17775, 17807, 17808, 17851, 17870, 18023) disagree with the EPA's rationale and assumptions for including startup/shutdown in the MACT standard. Commenter 17740 states that the EPA's justification for not establishing different requirements for startup/shutdown (include (1) EGUs do not normally startup and shutdown frequently, and (2) EGUs typically use cleaner fuels during startup) are unsupported and do not reflect actual EGU operating practices). Several commenters (17728, 17729, 17756, 17775) state the EPA's rationale does not account for the variety of ways EGUs startup and shutdown (types of fuel, duration varies), and is not based on actual emission observations during startup/shutdown (17728, 17775). Commenter 17807 states the EPA has not justified these assumptions based on actual startup/shutdown data.

Multiple commenters cited concerns about EPA assumptions regarding SSM and made statements such as the following: startup/shutdown periods are predictable and routine (17691, 17821); startup/shutdown periods are not predictable and routine (17807, 17758); EGUs do startup and shutdown frequently (18447); base load units do have startups and shutdowns (17772); EGUs do not startup frequently (17851); solid fuel-fired EGUs startup infrequently (17815); the duration of startup/shutdown is reasonably predictable (17316, 17386); the duration of startup can vary significantly (17756); the emissions during startup are variable (17316, 17386), due to transient combustion conditions (17386), affected by length of time unit has been shutdown (17316, 17386), and affected by ambient conditions at lite-off (17386); the number of startups in a given period can vary (17756); frequency and duration of startup/shutdown varies by unit and fuel blend (17758, 17807); base load units generally operate for long periods without an outage (17737); and historically, planned outages for maintenance and repair were fairly predictable and routine (17720, 17758).

Response to Comment 30: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

ii. Cleaner fuels.

Comment 31: Commenter 17740 states that units burn a wide array of fuels and the EPA cannot assume without additional justification that EGUs rely on cleaner fuels during startup. Commenters 17740 and 17774 also state that emissions may be higher than normal during startup periods, even when alternative (cleaner) fuels are used. Commenter 17728 states the EPA cannot assume that use of cleaner fuels accounts for startup/shutdown periods, and the EPA provides no data to support the assumption (flue gas conditions and particle size distribution may differ significantly during startup/shutdown than other periods). Commenter 17737 takes little comfort in the EPA's assertion that emission exceedances will not occur due to use of clean fuels during startup. Commenters 17737 and 17772 state that they use oil during startup with APCD bypass (FF, ESP) to avoid oil residue fouling, and Commenter 17737 states that bypass occurs until flue gas entering the FF is 160 ºF. Commenter 17756 states that they use oil for some units and use NG for others during startup. Commenters 17702 and 18018 state that many EGUs use oil for startup when NG is not available. Commenter 17702 states the EPA should consider an exception during startup/shutdown when an EGU is forced to use oil or when NG is not available. Commenter 17758 states the EPA has not provided support that use of different fuel for startup/shutdown would minimize emissions. Commenters 17815 and 17904 agree that solid fuel-fired EGUs typically startup on cleaner fuels, however note that some fire and transition to solid fuel during startup.

Commenters 17808 and 17870 state that most EGUs will switch fuels during startup, but for shutdown some will not switch fuels. Commenter 17702 states that manufacturer protocols for control equipment require additional delays for equipment startup when oil is used.

Response to Comment 31: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion.

iii. Combustion inefficient.

Comment 32: Commenter 17925 states that combustion is unstable (during startup), and design emission rates may not be achieved. Commenter 19114 states there are increases in products of incomplete combustion (PICs) (during startup). Commenter 17851 states that even when using cleaner fuel, the combustion process is inefficient during startup. Commenter 17851 notes that incomplete combustion would not impact fuel-derived HAP but would impact organic and PM emissions. Commenter 17904 states that boilers may not perform at the same efficiency during startup/shutdown.

Response to Comment 32: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion.

m. APCD not operated.

Comment 33: Numerous commenters (17316, 17386, 17402, 17623, 17675, 17715, 17740, 17757, 17774, 17820, 17851, 17904, 17930, 18539, 19114) state that APCDs do not operate during startup or most of startup; commenters (17725, 17757, 17820, 17904, 18014, 18498) state some emission controls should not operate until the system comes to the proper temperature or other conditions; commenter 17756 states that different control devices are brought online at different stages of startup.

Commenter 18018 states that manufacturer's often require delays for APCD for startup when using oil and not NG. Commenter 18018 states that the EPA should consider an exception to the compliance provision when an EGU is forced to use oil or NG is not available.

Multiple commenters (17623, 17702, 17740, 17774, 17815, 17904, 17930, 17975, 18018, 19114) indicate facilities follow manufacturer recommendations and/or good engineering practices for APCDs. Commenters (17815, 17904) state that solid fuel-fired EGUs operate with manufacturer-established constraints on APCDs during startup. Commenter 17815 states that manufacturer limits on APCD constrain an EGU's ability to comply with the standard during startup/shutdown. Commenter 17925 states that APCDs are not designed for higher loadings during startup/shutdown. Commenter 17930 states that manufacturer's recommendations protect APCDs against failure, explosive conditions, and ensure long-term functionality. Commenter 17740 states that EGUs have very few options for controlling, monitoring, or limiting emissions during periods of startup/shutdown due to equipment integrity concerns, technological limitations, and safety issues.

Multiple commenters indicate that APCDs are bypassed under certain operating conditions. Commenter 19114 states that APCDs need to achieve stable operating temperatures or other conditions. In general, fabric filters must have a specific stack gas temperature to avoid damage or failure of the bags (17851, 17740, 19121), and damage to the FF (17740, 19121). Commenter 19121 states that FF use during high loading of fuel oil cause bag blinding. Commenter 19121 states that use of FF during startup/shutdown may require replacement of all bags from each startup/shutdown event, and with five startups per year, this would be costly and may impact capture efficiencies. In general, ESPs must have a specific stack gas temperature (17740, 17930) to avoid short-term stability problems (17740), unsafe actions and long-term degradation due to fouling (17740), increased chances of wire damage (17740), or increased corrosion in chambers (17740). Commenter 17930 states that ESPs are on 85 percent of the coal-fired fleet. Commenter 17740 states that SDA require a minimum temperature, because the slurry feed rate is limited by the amount of moisture that the flue gas can evaporate. Commenter 17881 states that requiring the FGD system to operate during SSM, if technically feasible, is a waste of reagent, increasing ratepayer costs while providing no emission reduction or environmental benefit, damaging equipment and further resulting in unplanned shutdowns.

Commenter 18447 cites concerns for the safety ramifications of the rule. Commenter 18447 states that the EPA does not understand how to operate a boiler and the procedures that are necessary to operate safely during startup/shutdown. Commenter 18447 states that during shutdown or malfunction, the fuel to the boiler is shutdown and the ESP is powered down, to prevent unburned fuel from exiting the boiler and passing into the ESP where it would be ignited by the ESP if it remained powered up.

Commenter 17740 states that the warm-up time could theoretically be reduced by ramping up the fuel rate, but plants closely follow OEM warm-up period recommendations to avoid severe refractory damage and excessive metallurgical stresses due to rapid changes in temperature and wide variations in temperature across boiler and duct parts. Commenter 17740 states inconsistent heating could cause immediate failures such as tears or ruptures in support steel or heat transfer surfaces, posing risk to personnel. Commenter 17740 notes that failure rates would increase if rapid heating and cooling cycles were conducted, which would further increase startups and shutdowns.

Commenter 17772 states that if cooling pumps fail at shutdown, immediate bypass is necessary to avoid melting fiberglass tubes.

Commenter 17740 provides an example facility, a single unit plant that has upgraded with installation of new control equipment (SCR, FGD, and PJFF) that is considered BDT, modification of plant heat rejection system, and improvements to the boiler. Commenter 17740 states that the plant cannot operate the SCR and FGD during startup when the flue gas temperatures and boiler steam pressure are lower than required. The commenter indicates that the current permit limit requires lb/MMBtu for SO_2 and NO_X on a 30-day rolling average; the plant can meet the permit limits if there is only one startup within a given 30-day period, however, additional startups significantly jeopardize compliance for SO_2 and NO_X.

Response to Comment 33: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. These work practices take into account operation of

APCDs. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

n. APCD not efficient.

Comment 34: Numerous commenters (17402, 17623, 17705, 17715, 17725, 17736, 17757, 17758, 17772, 17774, 17807, 17808, 17820, 17821, 17870, 17877, 17902, 18014, 18498, 18539, 19114) state some APCDs do not operate efficiently (or optimum performance) during SS(M) periods. Commenter 17736 states that even the most advanced technologies have lower removal efficiencies during startup/shutdown periods. Commenter 17736 states that the EPA failed to recognize that control technologies cannot achieve the relied-upon result every hour of each day of the year. Commenter 17772 states the EPA must recognize how APCDs function and the limitation of APCDs during SSM in order to develop reasonable and achievable standards. Commenter 17623 states it is not practicable to meet the same stringent standards as would be required when APCD is fully functioning. Several commenters (17758, 17772, 17774, 17807, 17821) state that emissions may be greater during startup/shutdown periods because APCDs do not operate efficiently until steady-state is achieved. Commenter 17856 states SO_2 emissions are higher from the scrubber and NO_X and Hg emissions from SCR are higher during first few days of startup. Commenter 17725 states there may be periods when a source would not be able to comply with the standards because the control device does not operate at peak performance until certain operating conditions and flue gas temperature are achieved. Commenter 17821 states that FGD systems require 24 to 36 hours for startup to develop the proper scrubber liquor chemistry, and to achieve the SO_2 emission reduction.

Commenter 17736 states that ESPs yield lower removal efficiencies during startup due to low temperatures; Several commenters (17736, 17772, 17821) state that SCR effectiveness cannot be realized until the unit reaches a specific temperature. Commenter 17821 notes that the SCR performance impacts Hg oxidation and stack Hg emissions and therefore impacts the ESP performance. Commenter 17772 states that SCR contribution to Hg removal is high during normal operation, with the scrubber and ESP achieving 90 percent Hg removal, but is minimal during startup where the scrubber and ESP achieve approximately 65 percent Hg removal.

Commenter 17975 states that the EPA has failed to consider whether FF or other APCDs can substantially reduce emissions during startup/shutdown and maintenance. Commenter 17975 states that if other APCDs can reduce emissions, the PM limits must be based on superior technologies and not those APCDs that are not designed to operate effectively during startup/shutdown.

Response to Comment 34: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. These work practice standards take into account operation of APCDs. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

o. Rule clarifications.

i. Definition for SSM.

Comment 35: Several commenters (19536, 19537, 19538) state that the EPA does not define startup, shutdown, or malfunction.

Response to Comment 35: The rule describes what constitutes startup periods and shutdown periods in Table 3 to Subpart UUUUU of Part 63. Table 9 indicates that the definition of malfunction contained in general provisions (40 CFR Part 63.2) applies.

ii. Period for emissions averaging.

Comment 36: Commenters 17808 and 17870 state that averaging emissions over 30 boiler operating days is only relevant for CEMS but is not relevant for units conducting monthly or quarterly performance testing because these EGUs are not averaging emissions during startup/shutdown periods.

Commenter 17772 suggests that an annual limitation measured could be established for SSM periods for uncontrolled emissions for some limited number of hours.

Response to Comment 36: The commenters are correct that the 30 (or 90, as discussed elsewhere) boiler operating-day rolling average will only apply to sources demonstrating compliance through the use of CEMS or other continuous monitoring mechanisms. For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits; therefore, the commenter's suggestion that annual averaging be applied for startup and shutdown periods is moot. See the preamble for discussion. We do not believe that annual averaging times are appropriate for malfunction events. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

iii. Definition of boiler operating day/subpart Da.

Comment 37: Several commenters (17756, 17775, 17820) state the "boiler operating day" definition is not flexible to account for periods of shutdown, and recommends the EPA specify a minimum number of operating hours necessary to calculate a 30-day rolling average. The commenters indicate that if the requisite number of hours is not obtained, then the EGU may combine data from that period with data from the next 30-day period until the requisite number of hours is obtained. The commenters indicate this is similar to subpart Da for calculation of a 24-hour average in section 60.48Da(g)(3), which requires a minimum number of valid hours to calculate an average. Commenters (17820, 17886) suggest the EPA define a "boiler operating day" as operating 75 percent of the day, or 18 hours or more. Commenter 17886 states that operating days should be defined as 18 hours or more operation and if less than 18 hours should be excluded from the 30-day average.

Several commenters (17316, 17386, 17772) indicate that 40 CFR part 60 subpart Da rule revisions exclude startup/shutdown periods from 30-day averaging. Commenters (17715, 19114) state that excluding startup/shutdown periods from emission limits would follow precedent in numerous rulemakings.

Response to Comment 37: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits so this comment is moot. These work practice standards take into account operation of APCDs. See the preamble for discussion.

iv. Other.

Comment 38: Commenter 17675 states there should be allowances for alternative compliance limits or alternative monitoring for startup/shutdown periods, especially for acid gas and SO_2, when APCD are being brought online (or kept online during shutdown). Commenter 17675 recommends that section 63.9991(a)(1)(iii) be modified to allow a short, 8 to 12 hour, startup.

Commenter 17761 suggests, in conjunction with a longer emissions averaging period, that the EPA impose a work practice relative to a time limitation on what constitutes a startup or shutdown (e.g., 20 hours for startup, etc.), and to the extent that the startup exceeds the defined time, the facility would either have to abandon its startup efforts, justify a claim of malfunction, or utilize such emissions during that extended period in the emission averaging calculation to demonstrate compliance.

Response to Comment 38: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. These work practice standards take into account operation of APCDs. See the preamble for discussion.

p. Weighting startup/shutdown.

Comment 39: Several commenters suggest that the EPA weight the startup/shutdown emissions based on heat input. Commenter 17775 suggests weighting startup and shutdown values by heat input would be a more effective way of normalizing the impact of such events, and is consistent with the rationale the EPA provided in the proposed revision to 40 CFR part 60, subpart Da. Commenter 15678 states that fuel specific CO_2 concentration should be used for calculating emissions in lb/MMBtu during startup/shutdown periods.

Commenter 17886 states that the 30-day average should be a heat input average, so that emission rates for low fuel burn and heat input are appropriately weighted with higher fuel burn and heat input.

Commenter 17772 recommends weighting the hourly values by flow rate. Commenter 17772 indicates that low flow rates (flue gas) for startup should not carry the same weight as high flow rates for normal operation. Commenter 17772 states that if there are short-term high emissions during shutdown, the emission rate on subsequent days when the unit is not operating (and the emissions are zero, but are not recorded because they are not measured during a “boiler operating day”) will remain elevated, creating additional days of apparent non-compliance.

Commenter 17820 suggests weighting the startup/shutdown emissions by adding the mass emissions for each hour (lb/hr) for a total mass (lb) for the 30-day periods and dividing by the sum for each hour of the heat input (mmBtu/hr) for a total heat input (mmBtu) for the 30-day period, resulting in a lb/mmBTU 30-day average that more accurately accounts for startup/shutdown with less impact for startup/shutdown events.

Response to Comment 39: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion.

2. Separate standards/work practice standards for SSM.

a. Support separate standards.

Comment 40: Several commenters (17730, 17886, 19120) state the EPA must establish emission standards for startup/shutdown periods. Commenter 17740 states that if the EPA does not establish a 12-month rolling average, the EPA should establish work practice standards for startup/shutdown periods. Several commenters (17730, 17737, 17930) state the EPA must establish separate emission standards for startup/shutdown periods, or must extend the averaging time. Commenter 17677 states the EPA should consider removing startup/shutdown data from the continuous compliance demonstration data, or allow manufacturer's/site best work practices. Commenter 19122 recommends higher alternative PM limits or a work practice standard.

Numerous commenters (16849, 17383, 17402, 17627, 17638, 17677, 17689, 17712, 17715, 17716, 17720, 17722, 17724, 17725, 17728, 17729, 17730, 17736, 17737, 17740, 17756, 17758, 17772, 17774, 17775, 17795, 17808, 17813, 17815, 17820, 17821, 17870, 17876, 17877, 17878, 17885, 17886, 17902, 17904, 17909, 17925, 17928, 17930, 18025, 18037, 18428, 18429, 18498, 18539, 19032, 19114, 19122, 18023) recommend work practice standards during periods of SS(M). Many commenters (17402, 17627, 17638, 17715, 17716, 17720, 17725, 17736, 17737, 17740, 17756, 17758, 17774, 17775, 17795, 17808, 17815, 17816, 17820, 17856, 17870, 17878, 17886, 17902, 17904, 17925, 17928, 17930, 18014, 18025, 18037, 18428, 18429, 18498, 18539, 18023) note that work practice standards are required in the Boiler MACT rule; Multiple commenters (17383, 17689, 17712, 17724, 17740, 17757, 17758, 17774, 17813, 17876, 17885, 17909, 19032) state that previous (HAP) rulemakings required work practices for startup/shutdown events. Commenters 17627 and 17816 state that the EPA determined in Boiler MACT rule that MACT emissions limits do not apply to startup/shutdown. Commenter 17740 states the same reasons that the EPA established work practice standards for startup/shutdown periods in Boiler MACT apply here for EGUs, and the EPA offers unsupported assumptions as its only grounds for continuous compliance with emission standards. Commenter 17758 notes the EPA provides no explanation or justification why utility boilers are subject to more rigorous numeric standards. Commenters 17627 and 18037 note the EPA provides no compelling reason why MACT emission limits apply to EGU boilers during startup/shutdown but not to other boilers and industrial furnaces. Commenter 17776 states the EPA provides no reason for the different approach. Commenters (17878, 18428) state the EGU and Boiler source categories are similar. Commenter 17930 states that work practice standards are more appropriate for startup/shutdown.

Commenter 17623 states the EPA should propose a work practice standard during SSM periods because: emission standards are not practicable; data collected during SSM periods are from CEMS but do not include all pollutants regulated, particularly Hg from certain kinds of CEMS; and emission standards are not economically practicable because collecting SSM period data would involve significantly altering measurement techniques and may require manual monitoring.

Response to Comment 40: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action See also responses below that address the issue of determining compliance during malfunction events.

b. Sierra Club Decision.

Comment 41: Multiple commenters (16849, 17402, 17691, 17732, 17736, 17740, 17758, 17761, 17774, 17775, 17807, 17808, 17815, 17851, 17904, 17930, 19536/19537/19538) cite the *Sierra Club* court decision that vacated SSM exemptions. Multiple commenters (17383, 17689, 17712, 17724, 17813, 17876, 17885) agree that court decisions indicate that HAP regulation must account for startup/shutdown events.

Several commenters (17732, 17775, 17904, 17930) state that section 112 only requires that some section 112 compliant standard apply at all times. Several commenters (17732, 17775, 17930) state that section 112 does not require that one standard apply to all periods. Commenter 17772 states that the court case clarified that providing continuous emission reduction did not mean that a single standard for all periods was required. Commenter 17930 does not support the Sierra Club decision, and states that it is clear that the decision does not require one uniform standard at all times.

Commenter 17758 points out that the discussion of CAA section 112(h) in the *Sierra Club* decision and the decision itself do not constrain the EPA's ability to choose work practice standards in lieu of numeric standards. Commenter 17736 states that Sierra Club decision should not be treated as authoritative or supportive of the EPA's action in this rulemaking, as Sierra Club only bars the EPA from providing units with a blanket exemption, and the court did not hold that SSM periods must be included in MACT standards.

Commenter 17761 states the SSM Exemption court case does not dictate the onerous and potentially unachievable result set forth in the rule. Commenter 17904 states that the EPA has gone well beyond the Sierra Club decision by not only providing no exclusions, but also failing to offer alternative provisions addressing excess emissions during startup/shutdown. Commenter 17904 states that the EPA does not explain why these periods cannot have alternative standards.

Commenter 18539 states that applying a different standard during SSM is consistent with section 112. Commenter 18539 states that the court has held that emissions standards could be different for SSM and that work practice standards were permissible. Commenter 19121 states that CAA does not allow exemptions for SSM.

Commenter 17758 states that EPA cited to *Sierra Club v. EPA* (551 F.3d 1019) in both the boiler MACT and the EGU MACT and came to disparate conclusions that continuously applicable numeric standards are required at all times. According to the commenter, the court did not find that numeric emission limits under section 112(d) were required during SS periods. The commenter states that work practice standards under section 112(h) would satisfy the requirements of *Sierra Club* and EPA can choose to use work practice standard in lieu of numerical standards.

Response to Comment 41: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. As explained in those preambles, the EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. As the EPA further explained, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. Setting work practice standards under section 112 presents the same issues as setting numerical emission limits given the varied nature of malfunctions.

c. CAA section 112(h).

Comment 42: Multiple commenters (17716, 17730, 17736, 17740, 17758, 17774, 17775, 17815, 17904, 18429, 18023) cite section 112(h) and state that section 112(h) allows work practice standards. Several commenters (17740, 17774, 17775, 17815, 17904, 18023) note that emissions cannot be measured during SSM, that it is not feasible to prescribe or enforce an emission standard, and refer to the 112(h) CAA definition of the phrase "not feasible to prescribe or enforce" which includes any situation in which the Administrator determines that the application of a measurement methodology to a particular class of sources is not practicable due to technological and economic limitations. Commenters (17716, 17720, 18023) state the EPA must provide a separate work practice standard for SSM because it is not technically feasible to complete stack testing (and monitoring, 17720) during these periods.

Multiple commenters (17402, 17716, 17725, 17736, 17740, 17758, 17820, 17870, 17904, 17925, 18014, 18025, 18498, 18539, 18023) also point out that the EPA found in Boiler MACT that it is not technically feasible to complete stack testing or monitor during startup and shutdown. Multiple commenters (17402, 17716, 17725, 17740, 17904, 18037, 18539, 18023) state the same measurement problems (and technological difficulties, 17740) exist for EGUs. Commenters 17740 and 17758 note that Boiler MACT units and EGUs are substantially similar, and commenter 17740 states that the EPA has recognized previously that ICI boilers and EGUs are virtually identical. Commenter 17740 notes that the EPA attributes differences between ICI boilers and EGUs to size of units, boiler/furnace technology, and portion of electrical output for sale, but none of these differences allow EGUs to complete testing requirements during startup/shutdown periods. Commenter 17758 states that EGUs have the same issues as ICI boilers with respect to emission testing.

Commenter 18037 states it is not feasible to obtain sufficient data for startup/shutdown. Commenters 17725 and 17904 state that no technical feasibility for stack testing and monitoring leaves the EPA and the regulated community without a practical way to accurately determine emissions during startup/shutdown. Commenter 18023 has evaluated stack testing times and relays that total PM testing would require 8 to 10 hours and metal HAP and acid gas testing would require minimum of 16 hours. Several commenters (17725, 17820, 18014, 18498) state it is uncertain whether representative measurements could be obtained during startup/shutdown due to dynamic flue gas conditions and technical limitations with measurement technology. Commenter 18023 states that startups are transient periods where heat input, fuels, and gas flows continually change, and stack testing is impossible due to load fluctuations. Commenter 17851 states that testing during transient conditions is difficult. Commenter 17851 states that running EPA Reference Method 5 during startup would require 6 to 8 hours to complete a single test, but the conditions would have changed so significantly it would be impossible to understand what the data meant or extrapolate the data. Commenter 17851 notes the same is true for CEMS data during startup.

Response to Comment 42: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. As explained in those preambles, the EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. As the EPA further explained, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. Setting work practice standards under section 112 presents the same issues as setting numerical emission limits given the varied nature of malfunctions. See also responses below that address the issue of determining compliance during malfunction events.

d. Performance testing and measurement issues.

Comment 43: Commenter 18034 opposes any requirements to require stack testing during startup/shutdown. Commenter 18034 states that requiring stack testing during potentially dangerous plant operations that could place testing personnel at risk is inappropriate.

Commenter 17815 states that during startup/shutdown, the EGU exit gas temperature and flow rate are not at steady state, and it is impossible to collect condensable and filterable PM samples. Commenter 17815 states it is not reasonable to establish filterable PM as a surrogate with no reasonable ability to measure. Commenter 17737 states there are significant challenges in collecting accurate emissions data during startup (commenter cites UARG comments).

Commenter 17912 states that the EPA incorrectly assumed that measuring and monitoring equipment will function properly under these conditions. Commenter 17912 states that the infeasibility of obtaining valid stack tests under SSM means there is no way to provide assurance that a unit could achieve the limits.

Commenter 18021 states that the EPA must account for SSM in the test protocols that influence compliance.

Commenter 17736 states control device operating characteristics during full load testing is not representative of the range of operating characteristics that a unit may experience on any given day.

Commenters 17725 and 17904 state that monitoring equipment cannot operate accurately during SSM periods due to transient flow and flue gas conditions. Commenter 17725 states that since monitoring data for SSM periods are not representative of normal operations and are of suspect quality, the EPA should adopt an approach where they would not be included in data averages used to determine compliance and missing data substitution procedures. Commenter 17725 recommends that the EPA provide clarity in the rule for how such periods would be treated.

Response to Comment 43: CEMS data during startup and shutdown will not be used for purposes of calculating 30-day averages under the final rule. For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits and thus commenters concerns related to monitoring during such periods is moot. See the preamble for discussion.

For malfunction periods, the EPA does not agree with the commenters that CEMS will not provide data during malfunction periods (unless the malfunction is related to the CEMS) and commenters provide no support for their assertion that data cannot be obtained. To the extent an EGU owner or operator has not installed CEMS or believes a CEMS reading during a malfunction event is in error (i.e., shows non-compliance) over the averaging period the EGU owner or operator may use other available means (including engineering judgment) or information to demonstrate that the source complied with the standard.

e. Suggestions for work practice requirements.

Comment 44: Multiple commenters (17677, 17714, 17725, 17808, 17870, 17902, 17925, 17928, 18025) suggest that work practices should include or be based on manufacturer recommended practices. Several commenters (17725, 17870, 18025) recommend that, as in Boiler MACT, the EPA require units to follow manufacturer's specifications for minimizing emissions during startup/shutdown (as in 40 CFR part 63.7530(h)). Commenter 18025 also suggests that rather than referring to "manufacturer's recommended procedures", the EPA could refer to standard industry procedures to account for instances where more than one manufacturer has supplied different components. Commenter 17772 suggests the work practice standard take into account the boiler configuration, boiler type, and safe operation of the unit. Several commenters (17725, 17774, 19032) state the work practice standard should account for boiler type and control equipment. Commenter 17816 states that work practices should be specific to a unit's boiler type, operational characteristics, and APCDs.

Commenter 17774 states that sources should have to address malfunctions as soon as safely practicable. Commenter 17774 states facilities have large incentives to address malfunctions that may lead to excess emissions since facilities have emission limits under a number of EPA programs.

Commenter 17174 states the EPA should explain the reasoning for not requiring SSM plans. Commenter 18037 recommends a SSM plan be included in the Title V permit as an appropriate work practice standard. Commenter 17691 suggests the EPA should require startup/shutdown plans, for consistency with the recent Boiler MACT standard, since startup/shutdown events are predictable and routine.

Response to Comment 44: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. The EPA is setting standards that apply at all times, including periods of startup and shutdown and periods of malfunction. With such standards in place, sources have ample incentive to plan for and achieve compliance during startup and shutdown and during malfunctions, so there is no longer any reason to require sources to develop SSM plans

f. Operating parameters for APCD.

Comment 45: Several commenters (17820, 17821, 17868) state that work practices should be established in lieu of operating parameters for APCDs. Commenters 17821 and 17868 state that the EPA has no basis to expect that operating parameter limits established during performance tests will be achievable during SSM. Commenter 17821 states that the EPA established enforceable operating parameters in Boiler MACT but made it clear that those limits do not apply during SSM. Commenter 17820 states that operating limits for operating parameters for APCD should not apply during startup/shutdown. Commenters 17820 and 17868 state that the EPA requires sources to establish control device operating parameter levels that are dependent upon load during periods of "maximum normal operating load," or other frequently used loads, and then maintain those levels during other periods, including startup and shutdown.

Several commenters (17820, 17821, 17868) state that the EPA assumptions regarding startup/shutdown are not applicable to APCD operating parameter limits, which are based on 12-hr averages established during the performance test (maximum normal operating load) and not based on startup/shutdown. Commenter 17820 states that startups on large units take longer than 12 hours, so there is no allowance for periods of startup/shutdown in the parameter operating limit.

Response to Comment 45: The final rule does not provide for operating parameter limits for air pollution control devices. Please see the final preamble and responses to comments under Comment Code 5A05. For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

3. Other averaging periods.

a. General.

Comment 46: Commenter 17774 recommends a longer compliance period to provide flexibility and accommodate SSM events. Commenter 16849 suggests a longer averaging period, as an alternative to not including SSM hours in the 30-day average. Commenters (17737, 17740, 17795, 17904, 17930, 19122) recommend the EPA establish a 12-month rolling average or annual average. Commenter 17772 recommends moving to a 90-day or longer boiler operating day average.

Commenter 17730 states the EPA must establish separate emission standards for startup/shutdown periods, or must extend the averaging time.

Commenter 17737 states that if the EPA does not establish a work practice standard, then the EPA should use a 12-month rolling average (17737, 19032), or modify the 30-day rolling average by establishing a minimum number of hours to qualify as a boiler operating day and averaging all hours within the 30 boiler operating days (17737).

Commenter 17930 states that if a work practice is not implemented, the EPA should extend the averaging period to annual averaging and increase the emissions limit for all pollutants to better account for SSM emissions.

Commenter 17740 states that because the EPA is including emissions from non-steady state operations, including SSM and load following operations, the averaging period should be lengthened to a 12-month rolling average, calculated monthly. Commenter 17740 states that especially for single units that cannot be part of a multi-unit plant's averaging plan, the averaging period is highly important in dealing with these non-steady state events. Commenter 17740 notes that a 12-month rolling average for all HAP would achieve environmental protection yet provide needed operational flexibility and accommodate real-world operating conditions. Commenter 17795 states that a 12-month averaging period would ensure operational flexibility, allowing economic consideration to be part of dispatching and operating decisions.

Commenter 17795 states that there is no logical reason for providing more flexibility for facilities averaging multiple units than for facilities with a single unit or common stack.

Commenter 17761 states the EPA should extend the averaging period to account for routine and required maintenance, such as the required shutdown and startup required to inspect burners under this rule. Commenter 17761 states that the burner inspection outage time alone, along with required adjustments or repairs, could cause a facility to exceed the 30 boiler operating day average emission limit, particularly since there is both a shutdown and startup. Commenter 17761 states that to comply, facilities will have to take outage both to install controls and to perform assessments required by the rule, so that facilities may be forced into a situation that upon startup they are out of compliance.

Commenter 17774 states the EPA should lengthen the averaging period to provide needed flexibility to accommodate the range of operating events, including SSM events. Commenter 17761 notes that longer averaging periods for all emissions limits (such as an annual or semi-annual average) to fully account for the emission variability during these startup and shutdown periods are consistent with the holding in *Sierra Club* as emissions limits would continue to apply to facilities at all times.

Response to Comment 46: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. As explained in those preambles, the EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards and thus we are not revising the averaging time in the final rule to account for malfunction emissions. We believe that the 30 day averaging period provides the appropriate level of flexibility for the regulated industry and that longer averaging periods would inappropriately weaken the standards and limit our ability to evaluate source compliance on an ongoing basis (see RTI memorandum). In addition, the commenters' expressed concern about including startup and shutdown period in the averaging is no longer relevant in light of the inclusion of work practice standards for such periods in the final rule.

b. Kushner letter.

Comment 47: Commenter 17761 states that there is precedent in the Kushner Letter that the agency would provide compliance flexibility to sources that implemented appropriate responses (i.e., good faith efforts) to SSM events and would provide longer averaging periods (annual or semi-annual) (EPA Office of Civil Enforcement Interpretative Letter from Director Adam Kushner, July 22, 2009).

Commenter 17904 cites the Kushner Letter and requests that the EPA be consistent with the guidance in the letter, by averaging over a long period of time, e.g., yearly.

Response to Comment 47: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. For malfunctions, the EPA is finalizing the proposed affirmative defense language for exceedances of the numerical emission limits that are caused by malfunctions. See the preamble for discussion.

The Kushner letter did not state that EPA would necessarily provide longer averaging periods in promulgating new standards. In assessing the immediate impact of the *Sierra Club v. EPA* decision, the Kushner Letter merely noted that many sources may not have difficulty complying with existing standards during periods of SSM even if they lost the SSM exemption because of averaging periods built into those rules.

4. Diluent capping and electrical production.

Comment 48: Commenter 17648 agrees with the options for calculating input-based emissions based upon a default diluent value or fuel specific CO_2 concentration, or calculating output-based emissions using an electrical production rate of 5 percent of rated capacity during startup/shutdown periods.

Commenter 17767 supports use of minimum default values for the diluent and power generation numbers for startup/shutdown for parameters monitored by CEMS and by Low Emitting EGU methodology.

Commenter 17923 recommends the rule allow for alternative unit specific lb/MWh emission calculations, given that the 5 percent of rate capacity value could potentially cause overestimates resulting in artificial compliance issues.

Commenter 17821 states the EPA should define the default CO_2 value for various fuel types, just as it has for O_2. Commenter 17821 urges the EPA to define a default CO_2 value of 5 percent for coal-fired boilers for startup/shutdown, and the EPA should not leave it up to the regulated community as no two companies would choose the same value and lead to discrepancies. Commenter 17715 states that diluent capping during startup/shutdown periods is appropriate. Commenter 17715 recommends including a table in the rule listing the appropriate CO_2 diluent values, notes that the O_2 diluent value is not appropriate, and recommends use of the diluent cap values already defined in part 72 of 5 percent for CO_2 and 14 percent for O_2 for coal-fired EGUs, which would harmonize the two rules and provide adequate margin in the data. Commenter 17821 also supports a value of 5 percent CO_2, consistent with part 75. Commenter 17715 states the equivalent values for reporting lb/MWe are too low and should be changed to 10 percent.

Commenter 17904 states that startup/shutdown emissions cannot be confirmed by standard methods. Commenter 17904 states that the EPA recognizes measuring and monitoring during startup/shutdown is problematic. Commenter 17904 states that the EPA ignores the fact that there are no appropriate methods for accurately determining a representative value for pollutant concentrations. Commenter 17904 notes that the inclusion of diluent values in a 30-day compliance period would appear to disregard both measurement inaccuracies and variability of pollutant concentrations.

Several commenters (19536, 19537, 19538) state that no compliance monitoring is required during SSM. The commenters state that the monitoring provisions do not require any testing during periods of startup, shutdown, and malfunction and thus provide no means to determine if the standards are met during these periods. The commenters state that the default diluent value or the corresponding fuel specific CO_2 concentration for use in calculating emissions in units of lb/MMBtu or lb/TBtu during startup/shutdown periods does not assure continuous compliance during these periods. Commenters state that because no testing is required during SSM periods, even assuming the diluent requirement would address SSM, it would never have to be used as no SSM testing is required.

Comment 49: Commenter 17801 suggests wording changes for the electrical output to be applied during startup/shutdown to reflect when electric production actually exceeds 5 percent of the rated capacity, so that the default use does not result in an underestimate of power generated and overestimate of output-based emissions: For calculating emissions in units of lb/MWh or lb/GWh only during startup or shutdown periods, use a nominal electrical production rate of equal to 5 percent of rated capacity until the measured electrical production rate exceeds 5 percent of rated capacity.

Several commenters (17740, 17758, 17776) state that the EPA does not address these concerns (that there are equipment integrity concerns, technological limitations, economical issues, and safety issues]) but accounts for variable conditions by using a default value and specifying electrical production rate; by proposing these default values and production rates, the EPA acknowledges that it is not feasible to test and monitor emissions from EGUs during startup/shutdown. Commenter 17821 states that use of default values (10%) only addresses the limitation of the equations when using CEMS, it does not address that the emissions themselves are different during startup/shutdown. Multiple commenters (17758, 17776, 17912, 19536, 19537, 19538) state that the EPA does not explain how the default values were selected or why they are appropriate and accurate proxies for emissions during SS(M). Commenter 17925 does not understand how the EPA determined these parameters.

Response to Comments 48 - 49: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble for discussion. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. We agree with the commenters that the rule does not require formal performance testing during SSM periods. However, as noted above, we believe that it is important to collect data during all periods including SSM periods, as the rule requires when conducting any continuous monitoring. Sources who install CEMS or other continuous monitoring devices are required to operate the monitoring equipment and collect data at all timesthe process unit is operating and at the intervals specified in the rule, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities and any scheduled maintenance as defined in the unit's site-specific monitoring plan. Sources who conduct continuous monitoring will have HAP and other emissions data during SSM periods. Sources who opt to conduct periodic testing will not have data collected during malfunction periods. A source who experiences a malfunction event may use any available information to demonstrate that the source complied with the standard notwithstanding the malfunction.

5. Reliability issues.

Comment 50: Commenters 16849 and 18023 state that including SSM periods in the rule will cause reliability issues. Commenter 18023 states the ability to startup and shutdown units in a flexible manner and bypass controls for short periods are critical to operating a reliable electric system. Commenter 18023 states the rule does not provide regulatory relief during modes of operation such as SSM that are likely to result in higher emission rates, this will prohibit APCD bypass, and units will have to shut down if not able to meet MACT rule standard at all times. Commenter 18023 indicates that this will cause reliability challenges and will force additional shutdowns and restarts. Commenter 18023 notes there are additional reliability challenges for facilities that have multiple units served by a single APCD. Maintenance outages are scheduled for planned outages at one or more units; however Commenter 18023 states that transmission requirements may demand a certain amount of generation from that plant that could oblige the remaining units to operate while the control is offline. Commenter 18023 states the prohibition of emissions bypass under even these special circumstances could result in transmission consequences for areas served.

Commenter 17902 states the need for EGUs to provide uninterrupted reliable power is contrary to maintaining operations with frequent malfunction.

Response to Comment 50: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. These work practice standards take into account operation of APCDs. See the preamble for discussion. Given the inclusion of the work practice for startup and shutdown periods, we believe those comments are now resolved as they relate to startup and shutdown periods.

Concerning malfunction, we question the scope of this problem notwithstanding commenters assertions. Commenters have not provided information on the scope of this alleged problem or the likelihood that sources would have the large number of malfunction events that commenters describe. As stated in response to other reliability related comments, we believe we have identified mechanisms to address reliability issues associated with implementation of this final rule.

We address APCD maintenance, bypass stacks, our approach to malfunctions, and reliability issues elsewhere in the final rule record.

6. Malfunctions.

a. Support or oppose malfunction approach.

Comment 51: Several commenters (17772, 17807, 17902, 18428) support the malfunction exclusion. Commenter 17648 states that the EPA decision not to include malfunctions is reasonable, aligns with purpose of section 112, and malfunctions do not reflect normal variability in operating conditions. Commenter 17648 states the EPA already accounted for variability for typical operating conditions and it should not make further accommodations for malfunctions. Commenter 17772 also states they would support some alternative standard that is based on real data that recognized emissions are higher during malfunctions.

Commenter 17774 notes that the EPA's decision not to differentiate malfunction periods is not based on any data. Commenter 17774 notes the EPA's reference to the precedent that standards that factor in the variability of emissions under all operating conditions are reasonable. Commenter 17774 went on to state that in this case, it would be both reasonable and appropriate for the EPA to based the MACT standard on data that includes malfunctions. Commenter 17774 states that if the EPA chooses not to include such malfunction data, it cannot expect sources to comply with general emission limits during malfunction periods.

Commenter 17730 states that if malfunctions are included in the compliance calculation, the emission standards should be raised to account for the variability or the averaging times should be lengthened to account for including malfunction emissions.

Commenter 17767 disagrees with the EPA's statement that malfunction events are unlikely to lead to noncompliance.Commenter 17730 states malfunction events will cause sources to violate the standard. Commenter 17775 states that because the EPA does not factor malfunctions (even malfunctions of "best performing" sources) into its proposed standards, it is unlikely the standards will be achievable if a significant malfunction occurs. Commenter 17775 agrees with the EPA that equipment can and will fail unexpectedly, and that some allowance must be made for periods of malfunction. Commenters 17821 and 17877 state that even the best performing units or technology will occasionally fail (and malfunction). Commenter 17851 states that even the best operated and maintained facilities will have malfunctions. Commenter 17623 states that malfunctions leave the source with uncertainty about whether they will be penalized and vulnerable to citizen suits. Commenters (17623, 17821) appreciate that the EPA states that not all malfunctions will result in violation; Commenter 17821 states that sources are subject to the discretion of the EPA, state, and plaintiffs in citizen suits, and Commenter 17623 states that regulated sources are still subject to significant EPA and state discretion concerning such occurrences and hold the burden of proving an affirmative defense.

Commenters 17623 and 17774 state the EPA should not be able to set a MACT floor that does not account for malfunctions because it deems the data infeasible, while at the same time require compliance with the strict standard during malfunction periods. Commenters note that just because the EPA is not required to account for every conceivable malfunction does not mean it can set standards excluding data of any malfunction event.

Commenter 17775 states the application of numerical limits to such malfunctions without a defense to penalties clearly would violate the Due Process Clause and the Eighth Amendment prohibition on Cruel and Unusual Punishment. Although Commenter 17775 appreciates the EPA's willingness to exercise enforcement discretion and to provide a defense to civil penalties, the EPA's refusal to take malfunctions into account when setting standards is not reasonable.

Several commenters (17808, 17870, 18025) recommend the EPA or states maintain current enforcement discretion to address situations when a source fails to comply with a section 112(d) standard as the result of a malfunction. On the other hand, Commenter 17402 opposes the EPA's proposal to use its discretion to determine an appropriate response to malfunction events and it opposes EPA's affirmative defense proposal. The commenter has established a state-approved plan that it follows during malfunctions and breakdowns. The commenter believes this approach is preferable to EPA's proposal, in which there is a presumption of non-compliance. The plan incorporated in commenter's Title V operating permit application ensures that future malfunction events will be minimized and that best practices will be followed, whereas EPA's proposed approach is focused on after-the-fact penalty.

Response to Comment 51: The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. As explained in more detail in the preamble, EPA's approach to malfunctions is consistent with CAA section 112 and is a reasonable interpretation of the statute. While the EPA recognizes that malfunction events may lead to noncompliance, the EPA disagrees with commenter's statements concerning enforcement discretion. The EPA will consider the totality of circumstances of each case in determining whether and to what extent and enforcement response is appropriate. The commenter's suggestion that its state-approved plan is prefereable to the EPA's approach does not explain how an approach based on such a plan meets the requirements of section 112.

b. Work practice specific to malfunctions/Sierra Club Decision.

Comment 52: Commenters 17775 and 18023 suggest the EPA work with utilities to develop reasonable work practice standards under section 112(h) that take malfunctions into consideration. Commenter 17623 states the best approach is to require a work practice standard that ensures malfunction problems are addressed as soon as safely practicable.

Commenter 17775 states section 112 does not limit the EPA's standard setting obligation to "distinct operating modes." The commenter notes that as the D.C. Circuit ruled in *Sierra Club v. EPA*, CAA § 112 requires that some "section 112-compliant standard" apply at all times (not just during distinct operating modes). 551 F.3d 1019, 1027 (D.C. Cir. 2008). The commenter states that if the EPA has determined that it is not technologically or economically "feasible" to gather emissions data necessary to establish numerical emissions standards that "take malfunctions into account," the EPA should promulgate operational and work practice standards as section 112(h) specifies. To the extent the EPA is attempting to distinguish between the "impracticality" of taking malfunctions into account, and the "infeasibility" of prescribing and enforcing standards for such events, the commenter states that the EPA's position is difficult to square with the CAA.

Commenter 17775 states that specifying work practice standards for malfunctions is more consistent with the CAA, and the D.C. Circuit's interpretation of it in Sierra Club, than the EPA's proposed affirmative defense. Although the court found that the existing "general duty to minimize emissions" was not sufficient to qualify as a section 112(d) standard, and that the EPA had "not purported to act under section 112(h)," the commenter states that it also made clear that the CAA does not require that the same standard apply to all periods. Id. at 1021 (recognizing that "continuous" under CAA § 302(k) does not mean "unchanging"), 1028. In short, the commenter states that nothing prohibits the EPA from establishing section 112(h) standards for periods that include a malfunction, even if section 112(d) standards apply at other times. In fact, the commenter states that establishing section 112(h) standards for malfunctions would be more consistent with the Sierra Club ruling than applying clearly unachievable standards and allowing a defense to penalties, since an unachievable section 112 standard is not "section 112-compliant." The commenter notes that it also would be more consistent with Congressional intent. By allowing work practice and other requirements under section 112(h), the commenter states that Congress clearly intended that sources be provided the opportunity to be fully in compliance with some standard at all times. The commenter states that nothing in section 112 suggests that Congress intended to require a source owner or operator to certify "violation" of a section 112 standard as a result of an event the source could not reasonably control. The commenter states that the

EPA should adhere to that intent and specify reasonable work practice or operational requirements for periods of malfunctions.

Response to Comment 52: The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. The EPA's rationale does not turn on whether malfunctions should be viewed as a distinct operating mode. Further, the EPA's rationale for its approach to malfunctions is not based on the criteria that must be met to justify a finding that it is not feasible to prescribe or enforce an emission standard under section under section 112(h). Section 112 (h)(2) provides that such a finding must be based on a determination that "a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State or local law" or "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." The EPA justification for its approach to malfunctions is unrelated to the findings required under section 112(h)(2). Thus, commenters' claim that the EPA's attempt to distinguish between the two "is difficult to square with the CAA" is without merit. As explained in the preamble to the proposed rule and this final rule, the EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. The EPA has further explained its view that accounting for malfunctions would be difficult, if not impossible given the myriad different types of malfunctions that can occur across all sources in the category. This rationale is not based on the factors set forth in section 112(h)(2).

c. Reporting.

Comment 53: Commenter 17775 states that the EPA's reporting requirements also raise some practical issues. Although some malfunctions will occur even at the best performing plants, the commenter states not all malfunctions will necessarily result in emissions above a numerical standard. With the longer averaging times the EPA has proposed, the commenter states that it is possible that elevated emissions from some malfunctions will be sufficiently compensated for during normal operation such that they do not result in exceedance of a 30-day rolling average. The commenter indicates that determining before the end of a 30-day period whether a malfunction will result in an exceedance of a 30-day rolling average may not always be easy. Commenter 17775 states that requiring EGUs to keep logs of malfunctions is not unreasonable, however, requiring notice to the EPA of events before the EGU even knows whether an exceedance will occur, requiring logs in response to exceedances (rather than malfunctions), or requiring that the exceedance occur at the same time as the malfunction, are not reasonable. Commenter 17775 suggests that the EPA rework its proposal to recognize that some malfunctions that ultimately result in exceedance of an emission limit (particularly those with longer averaging times) may occur long before the exceedance is recorded. The commenter notes that the EPA should simply require the maintenance of the appropriate records surrounding any event identified by the EGU as a malfunction and leave the reporting until after all of the data relevant to the compliance determination for the affected period are collected.

Commenter 17772 indicates that 40 CFR part 60 subpart Da rule and others exclude malfunction periods from 30-day averaging.

Response to Comment 53: The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action. See preamble and rule for discussion on related reporting requirements.

The commenters appear to be referring to reporting associated with the assertion of an affirmative defense, described in section 63.10001. The EPA agrees that the notice requirement associated with the affirmative defense may not be practical when a 30-day averaging period applies. The EPA is revising the notification requirement so that it reads " The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall 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 whether 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, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction."

d. Malfunction definitions.

Comment 54: Commenter 17775 notes that section 63.10005(a) makes a number of references to "excess emissions" however, there is no general definition of "excess emissions" in section 63.2. Commenter 17775 states that according to section 63.10(c)(7) and (8), "excess emissions" are supposed to be defined in the applicable subpart, but proposed subpart UUUUU contains no such definition. Commenter 17775 suggests the EPA issue a proposal to define "excess emissions" in the context of any final rule that uses the term.

Commenter 17736 notes that the definition of "malfunction" is sufficient for the Utility MACT rule.

Response to Comment 54: We disagree with the commenter. In defining the standard, we are in effect also defining emissions that are in excess of the standard. We have in this final rule established numerical emission standards that must be met on a 30-day rolling average. Emissions in excess of those levels over the established averaging period are considered excess emissions.

7. Affirmative defense.

a. Support or oppose AD approach.

Comment 55: Multiple commenters (17623, 17715, 17740, 17807, 17904, 17909, 17912, 18025, 18428, 19114) support affirmative defense (AD) for malfunctions; commenter 17722 generally supports the AD for excess emissions. Multiple commenters (17689, 17724, 17712, 17876, 17877, 17885, 19032) support affirmative defense concept but believe the EPA should articulate specific reasonable provisions in the rule.

Commenter 17975 states that requiring agencies to evaluate and rebut AD on a case-by-case basis is impractical and ineffective. Commenters (17689, 17712, 17877, 17885) state the EPA should not decide the appropriateness of individual situation retroactivity on a case-by-case basis based on vague changing guidelines. Commenter 17909 states the EPA should provide detailed guidance on how the provisions will be applied and rely on case-by-case review. Commenter 17912 notes that the EPA properly proposes flexibility for malfunctions. Commenter 17912 supports the EPA finding that it is reasonable not to account for malfunctions in emission standards.

Commenter 17902 states that short of excluding malfunctions, they support AD, however, the EPA should make it less burdensome. Commenter 17902 recommends the EPA remove items 7 through 9, because the information is redundant with items 1 through 6, are unnecessary, are not reasonably documented or quantified, are not expected to provide meaningful insights on how to avoid future malfunctions, and make the rule less impractical.

Commenter 17851 supports maintaining a regulatory provision for malfunctions, such as an AD. Commenter 17851 notes concerns that the AD implies the facility is guilty until proven innocent. Commenter 17851 states concerns that in calling it an AD even before it has been established to be a deviation, improperly shifts the burden to the facility. Commenter 17851 suggests the EPA establish a rebuttable presumption, rather than AD, where it is presumed the facility did everything in their power to minimize emissions, unless the EPA proves certain facts that are enumerated in rules. Commenter 17851 states the burden of proof would be on the EPA.

Commenter 18500 states that the steps associated with AD are highly prescriptive and infer that the failure to meet any step is a willful violation. Commenter 18500 states the standard should be moderated to match the risk to the violation, and to recognize that malfunctions are unanticipated failures.

Commenter 17730 states that AD still requires the source to document the event and defend itself to the EPA or in a court of law for violation of standard that was unreasonably established. Commenter 17402 recommends a SSM work practice plan in the Title V permit to minimize future malfunctions and ensure best practices are followed, similar to the malfunction and breakdown plan they developed for their title V application. Commenter 17902 states that EGUs are already required to minimize emissions during SSM under title V operating permit conditions. Commenter 18447 states that the [AD] response to a malfunction is heavy-handed and threatening. Commenter 18447 states that facilities are guilty until they go to great lengths to prove innocence. Commenter 18447 states that the EPA would do well to realize that even well-trained and well-intentioned employees can and do make mistakes.

Commenters 17402 and 17772 oppose the EPA's AD proposal for malfunctions. Commenter 17772 states that AD for malfunctions is inappropriate, overly complex, and unduly burdens both industry and the EPA. Commenter 17772 states that the EPA has improperly shifted the burden of proof to the facility, but the ultimate burden of proof to justify a civil penalty remains with the EPA, and the EPA should have to present clear evidence sufficient to persuade a judge or independent fact finder that the claimed malfunction should be disregarded for reasons such as poor maintenance, careless operation, or other preventable conditions. Commenter 17772 states the multi-part process for establishing the existence of a malfunction is overly complex and burdensome. Commenter 17772 suggests that any AD to be used should be limited to the definition in section 60.41Da. Commenter 17772 notes that the rule establishes 12 separate requirements and requires the EGU operator to carry a burden of proof for each one to comply; this is arbitrary and capricious. Commenter 17772 states that the 12 requirements are vaguely worded and will themselves become a primary focus of litigation; after a malfunction occurs, it is almost always possible for someone to allege there was some practice that could have been employed to prevent the malfunction.

Commenter 17772 also states their concerns that root cause analysis in section 63.10001(a)(9) will be used against the EGU operator, since a potential argument may be made that earlier implementation of the recommended correction would have prevented the malfunction. Commenter 17772 states that proposed rule section 63.10001(a)(5), for example, states that the accused must prove that "all possible steps were taken" to minimize the impact of the excess emissions. The commenter asks whether that means that if the EPA or some private litigate can imaginatively identify some step not tried, then the affirmative defense is rejected? The commenter goes on to note that if so, no affirmative defense would ever be successful -- some untried alternative or additional action could always be found by inventive counsel or expert witness. Similarly, commenter 17772 notes that proposed rule section

63.10001(a)(i)(2) states that the excess emissions "Could not have been prevented through ... better operation and maintenance practices." The commenter indicates this could be an impossible standard to meet if "better" is used to mean better than the practices actually employed by the accused. Commenter 17772 states that this vague and unworkable standard should, at a minimum, be modified to allow the accused to meet whatever burden of presentment or proof is applied by a showing that the operation and maintenance practices were consistent with good utility practice.

Commenter 17851 states the requirements in section 63.10001 are impossible to meet due to ambiguous terms such as "careful," "proper," or "better", and these terms must be defined in order to determine whether the criteria were met. Commenter 17851 states the EPA should drop references to "any" activity and "all" in this paragraph.

Commenter 17912 states that the AD is restrictive and vague. Commenter 17912 urges the EPA to set conditions for AD that a facility can actually achieve rather than setting a virtually insurmountable bar.

Commenter 17736 objects to the EPA's attempt to restrict the definition of "malfunction" such that the concept is eliminated albeit the EPA's proposed "affirmative defense." Commenter 17736 notes that determining whether no malfunction occurred if it "could have been prevented through careful planning, proper design, or better operation and maintenance," the EPA should explain what "proper design" and "better operation" is.

Commenter 17775 cites concerns regarding AD. Commenter 17775 states that section 63.10005(a)(1)(i) refers to an "unavoidable" failure, and although the difference between "reasonably preventable" and "unavoidable" may seem small, the EPA's rule seems to require a stronger showing than the definition anticipates in that it leaves room to argue whether a failure could have been prevented even if the acts necessary to do so were "unreasonable." Commenter 17775 indicates that other provisions in (a)(1), paragraph (ii) ("[c]ould not have been prevented"), (iii) ("could [not] have been foreseen and avoided, or planned for"), and (a)(5) ("all possible steps") - also seem to remove the requirement of "reasonableness." In contrast, the commenter notes that other provisions include references to practicability. At a minimum, Commenter 17775 states the EPA must revise its criteria consistent with the section 63.2 definition to include the concept of "reasonableness."

Several commenters (17383, 17712, 17876) state AD for malfunctions should be reasonable and the requirements well articulated. With respect to AD for malfunctions, Commenter 18023 requests that the EPA reconsider the criteria defining malfunctions to include the concept of "reasonableness" and to defer reporting until an exceedance has been recorded.

Commenter 17722 states that for language in section 63.10001(a)(5) "All possible steps were taken..." it should be clarified that those steps must be relevant to the excess emissions. The commenter also stated the term "possible" is subjective and could be replaced by "all steps needed, based on best professional judgment."

Commenter 17722 states that for language in section 63.10001(a)(9), it should be clarified that written root cause analysis should include all forms of documentation, including electronic records.

Commenter 17975 states that neither NSPS nor MACT standards appropriately deal with malfunction. Commenter 17975 states that the EPA must determine whether certain emission control technologies are less likely to malfunction and cause standards to be exceeded. Commenter 17975 states that if these technologies are available, the EPA should not provide an AD for malfunctions from emissions controls that are accident prone.

Several commenters (19536, 19537, 19538) state that the EPA'S AD for malfunctions is unlawful. Commenters state that the CAA makes clear how the courts are to assess civil penalties, whether a case is brought by the EPA or a citizen. 42 U.S.C. § 7413(e). The commenters note that Congress intended citizens to be able to enforce emission standards under the CAA using the full range of civil enforcement mechanisms available to the government, and, in the HAP context, subject only to the limitation that government not be "diligently prosecuting" its own civil enforcement action, CAA § 304(b)(1)(B), 42 U.S.C. § 7604(b)(1)(B). The commenters state that the EPA's rule proposal, by shifting this careful balance and contravening these mandates, violates the CAA.

Commenters state that the AD that the EPA proposes to allow in case of malfunctions goes directly against congressional intent in two ways. First, the commenters note that Congress expressed a clear intent as to how judges should determine the size of civil penalties whenever they are sought and thus Congress flatly barred the EPA from limiting when civil penalties can be assessed. *See Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984). In this proposal, the commenters note that the EPA acts outside of its delegated authority to limit civil penalties available in citizen suits or its own enforcement actions. Second, the commenters state that the proposal will impermissibly chill citizen participation, and the ability to win an effective, deterrent remedy, in CAA enforcement actions.

Commenters state that the AD is fatally flawed because the EPA cannot decide when civil penalties will not be allowed. The commenters state that the CAA itself spells out the only limits that Congress intended to impose on citizens' ability to seek and recover penalties in enforcement suits under CAA § 304, 42 U.S.C. § 7604. See 42 U.S.C. § 7413(e). By attempting to impose additional agency-created limits, the commenters state that the EPA exceeds its authority. The commenters note that Congressional intent on civil penalties is clear-they are a remedy available to citizen plaintiffs, and the CAA gives judges a list of factors to consider in assessing them. As such, the commenters state the EPA cannot interpret the statute to contravene that intent, and by attempting to rewrite this provision, via regulation, the EPA has done just that.

Commenters state that the CAA grants the EPA minimal discretion that only applies to administrative penalties, allowing the EPA to "compromise, modify, or remit, with or without conditions, any administrative penalty which may be imposed under [subsection 113(d)]." 42 U.S.C. § 7413(d)(2)(B). However, the commenters state there is no similar grant of authority to the EPA to compromise, modify or limit civil penalties that a court may impose under section 113(e) or section 304. The commenters state that section 304(a), 42 U.S.C. § 7604(a), grants courts the sole authority "to apply appropriate civil penalties" in citizen suits. The commenters note that the explicit reference to the EPA's ability to modify penalties in one subsection and its absence in the other subsection of the same provision can only be understood as an intentional decision by Congress that the EPA cannot contravene by rule.

Commenters state that citizen participation in CAA enforcement also will be hampered, in violation of citizens' rights to protect themselves from pollution and in direct conflict with congressional intent. The commenters state that the affirmative defense would likely be used on a routine basis by polluters seeking to avoid penalties, just as the malfunction exemption was. As a result, the commenters note that citizens who seek civil penalties against polluters in order to protect themselves and achieve the CAA's goals may be forced to engage in fact intensive disputes over the cause of emission violations and adequacy of responsive measures - an outcome Congress intended to prevent with the simple straightforward enforcement and penalty provisions in the CAA. As a result, the commenters note that enforcement of the CAA could suffer, for civil penalties provide a powerful deterrent to violators as Congress intended.

Commenters state that the AD also runs counter to two clearly 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 AD 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). The commenters state that both result from the technical burden the EPA imposes on citizens with the AD, and both render the defense impermissible.

In addition to these problems, commenters state there is simply no need for an AD to penalties to be written into the regulations and cause the harm that will result. The commenters note that the 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 42 U.S.C. § 7401. The commenters state that promulgating this affirmative defense is equivalent to giving polluters "get out of jail free" cards for serious emission exceedances and MACT violations. The commenters note that polluters are likely to claim that any violation of the standard is due to a malfunction in order to evade the requirements. The commenters state that allowing polluters to evade financial penalties - which are the real teeth of the standards - through this type of measure is likely to lead to polluters simply ignoring or factoring potential standard violations into their cost of doing business, rather than actually trying to prevent malfunctions and violations of the standards as a way to avoid financial losses from the application of penalties.

Commenters state that assuming arguendo that the EPA had authority to promulgate any type of affirmative defense to penalties for malfunctions, the EPA should also promulgate the following provisions:

1. A specific amount of compensatory damages should apply to each reported malfunction. These funds should be dedicated to enforcement, inspections, and monitoring in the local community around the specific facility, to create greater assurance that malfunctions will not happen again.

2. The EPA should modify the regulations so that the AD cannot be used by a specific facility or company more than once within a set period of time, such as 10 years. The AD should become automatically unavailable to a facility that has previously had a malfunction within the last 10 years, to ensure that this defense does not swallow the value of the standards.

3. The EPA should promulgate specific public reporting and notification requirements for malfunctions, or any emission exceedance that occurs of which an operator is aware. Specifically, the EPA should require that when a facility provides the EPA with a notification of a malfunction or emission standard exceedance under the regulations, this notice will be made publicly available on the EPA's website within 14 days. In addition, the EPA should promulgate the requirement that when such notification is made, the facility must also provide for community notification of the malfunction or emission standard exceedance within 2 business days, through an appropriate public forum that is designed to reach residents who live near the facility, including but not limited to a notice on the facility's own website (if it has one), a written notice to the local municipality and local school district, a press release to the local newspaper, radio, and TV news station that contains information community members may need to protect themselves and their families from the additional air pollution.

Response to Comment 55: For malfunctions, the EPA is finalizing the proposed affirmative defense language for exceedances of the numerical emission limits that are caused by malfunctions with minor revisions as discussed below. As the EPA explained in the preamble to the proposed rule, the 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 is including an affirmative defense in the final rule as we have in other recent section 112 and section 129 rules so as to balance the 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 EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." 42 U.S.C. § 7602(k)(defining "emission limitation and emission standard"). *See* generally *Sierra Club v. EPA*, 551 F.3d 1019, 1021 (D.C. Cir. 2008) (emissions limitations under CAA section 112 must both continuously apply and meet section 112's minimum stringency requirements, even during periods of startup, shutdown and malfunction). Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While "continuous" limitations, on the one hand, are required, there is also caselaw indicating that in some situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 "variant provisions" such as provisions allowing for upsets during startup, shutdown and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force." *See* also, *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375 (D.C.Cir. 1973). Though intervening caselaw such as *Sierra Club v. EPA* and the CAA 1977 amendments calls into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. 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. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating "upsets beyond the control of the permit holder." *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1272-73 (9^{th} Cir. 1977). *But see, Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1057-58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are "continuous" as required by 42 U.S.C. § 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

Further, the EPA's view is that the affirmative defense is consistent with CAA sections 113(e) and 304. Section 304 gives district courts jurisdiction "to apply appropriate civil penalties." Section 113(e)(1) identifies the factors that the Administrator or a court shall take into consideration in determining the amount of a penalty to be assessed only after it has been determined that a penalty is appropriate. The affirmative defense regulatory provision is not relevant to the amount of any penalty to be assessed under section 113(e) because if a court determines that the affirmative defense elements have been established, then a penalty is not appropriate and penalty assessment pursuant to the section 113(e)(1) factors does not occur.

In exercising its authority under section 112 to establish emission standards (at a level that meets the stringency requirements of section 112), the EPA necessarily defines conduct that constitutes a violation. The EPA's view is that the affirmative defense is part of the emission standard and defines two categories of violation. If there is a violation of the emission standard and the source demonstrates that all the elements of the affirmative defense are met, only injunctive relief is available. All other violations of the emission standard are subject to injunctive relief and penalties. The CAA does not require that all violations be treated equally. Further, a citizen suit claim under section 304 allows citizens to commence a civil action against any person alleged to be in violation of "an emission standard or limitation under this chapter." The CAA, however, allows the EPA to establish such "enforceable emission limitations." Thus, the citizen suit provision clearly contemplates enforcement of the standards that are defined by the EPA. As a result, where the EPA defines its emissions limitations and enforcement measures to allow a source the opportunity to prove its entitlement to a lesser degree of violation (not subject to penalties) in narrow, specified circumstances, as the EPA did here, penalties are not "appropriate" under section 304.

The EPA's view is that an affirmative defense to civil penalties for exceedances of applicable emission standards during periods of malfunction appropriately balances competing concerns. On the one hand, citizen enforcers are concerned about additional complications in their enforcement actions. On the other hand, industrial sources are concerned about being penalized for violations caused by malfunctions that could not have prevented and were otherwise appropriately handled (as reflected in the affirmative defense criteria). The EPA has utilized its Section 301(a)(1) authority to issue regulations necessary to carry out the Act in a manner that appropriately balances these competing concerns.

The EPA disagrees that the affirmative defense provision will hamper citizen enforcement. First, injunctive relief is still available and the threat of penalties would not deter violations in cases where all of the conditions of the affirmative defense have been satisfied because the affirmative defense criteria ensure that all reasonable steps were taken to prevent a malfunction that causes excess emissions. Further, litigating whether a source has met the affirmative defense will not burden citizen group any more or less than would litigating the appropriate penalty amount in the penalty assessment stage of a citizen suit enforcement action, because the 113(e) penalty assessment criteria and the affirmative defense criteria are similar and in fact overlap. For example, the requirement that the Administrator or the court consider "good faith efforts to comply" is bound to generate the type of fact-intensive disputes that the commenter complains of. In addition, several of the affirmative defense criteria are exactly the type of criteria the Administrator or Court might consider in determining whether a source made "good faith efforts to comply." For example, to take advantage of the affirmative defense, the source must prove by a preponderance of the evidence that, among other things, the excess emissions "were caused by an unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner" and "could not have been prevented through careful planning, proper design or better operation and maintenance practices" and "did not stem from any activity or event that could have been foreseen and avoided, or planned for."

Thus, the EPA does not expect the affirmative defense provision to significantly alter the burden of bringing a citizen enforcement action. For those cases that do proceed to trial, even in the absence of this affirmative defense, sources generally raise equitable arguments to argue for a low penalty and citizens often rebut such arguments. Therefore, as a practical matter, the EPA does not expect the affirmative defense provision to materially affect the practice of CAA enforcement.

Additionally, the affirmative defense is reasonable. The EPA's judgment is that the affirmative defense criteria capture the appropriate considerations in determining whether penalties are appropriate when a violation occurs as the result of a malfunction. As noted above, the affirmative defense criteria overlap to some extent with the penalty assessment criteria set forth in section 113(e), but are not identical. For example, size of business is one of the factors listed in section 113(e), but is not reflected in EPA's affirmative defense. This reflects the EPA's view that when a violation is caused by a malfunction, the size of the business is not relevant to whether penalties should be excused. If the violation was unavoidable and could not have been prevented, the EPA's view is that it would be unfair to impose a penalty no matter the size of the business.

The EPA is not adopting commenters' suggestion with respect to compensatory damages or limits on the frequency of use of the affirmative defense. It is not clear that EPA has authority to require the automatic imposition of compensatory damages and even if such authority exists, the EPA does not think automatic imposition of damages is appropriate. Ensuring that malfunctions do not recur can be handled through imposition of appropriate injunctive relief. In addition, the EPA's view is that it would not be appropriate to limit a source's ability to take advantage of the affirmative defense to one time over a specified period of time such as ten years given that the affirmative defense is only available when the source could not have prevented the excess emissions. With respect to commenters' suggested reporting requirements, the reporting requirements in the rules promulgated today already require malfunction reporting and the affirmative defense provisions require that parties choosing to assert the affirmative defense meet additional malfunction reporting requirements. Any such reports submitted to the EPA are publicly available pursuant to CAA section 114.

Further, the EPA disagrees with comments that criticize the affirmative defense criteria as being overly vague or unduly restrictive and complex. The EPA believes that courts are well equipped and often do evaluate and apply the type of criteria set forth is 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, the 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 EPA does not find persuasive commenters' concerns with potential use of the root cause analysis against the source. The purpose of the root cause analysis is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. A sources ability to do so with the benefit of hindsight after a malfunction has occurred does not necessarily mean that malfunction could have been predicted or prevented.

The EPA also disagrees with comments that criticize the affirmative defense for shifting the burden of proof. 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 the EPA's use of an affirmative defense to address excess emissions during malfunction events).

With respect to the comment that the affirmative defense should be stated instead in terms that, once a source has claimed that its excess emissions were related to a malfunction, it will not be considered to be in violation of the standards unless the enforcement authority demonstrates that the source is not entitled to claim the malfunction, the EPA does not agree that the affirmative defense should operate as the commenter suggests. The commenter improperly seeks to shift the burden of proof from the source to the EPA. It is the source, not the EPA, that has the information relevant to assess whether a particular event qualifies as a malfunction and meets the affirmative defense.

b. AD for startup/shutdown.

Comment 56: Commenters 17904 and 19120 request AD for excess emissions during startup/shutdown periods, similar to the AD provided for malfunctions. Commenter 17904 cites the NSPS (approved FIP for a station) where opacity standards apply at all times except during SSM (40 CFR 60.11), and AD applies to SSM. Commenter 17904 notes that unlike an exclusion, an AD does not excuse a source from continuous compliance. Commenter 17904 states that nothing in the Sierra Club decision precludes the EPA from including an AD for excess emissions during startup/shutdown.

Response to Comment 56:. The EPA is promulgating the affirmative defense for malfunctions only, not for periods of startup and shutdown. As explained in the preamble, the EPA believes that malfunction events should be treated differently than periods of startup and shutdown, which are predictable and routine aspects of a source's operations. In contrast, the EPA has determined that CAA section 112 does not require that emissions that occur during malfunctions be factored into development of CAA section 112 standards. Because startup and shutdown periods are part of a source's normal operations, the same approach to compliance with, and enforcement of, applicable emissions standards during those periods should apply as otherwise applies during a source's operations. Further, as explained above, periods of startup and shutdown – but not malfunctions -- are taken into account when establishing section 112 emissions standards. For these reasons, the EPA does not believe it is appropriate to apply the affirmative defense provision to startup and shutdown periods.

c. Reporting timeline.

Comment 57: Commenter 17912 states section 63.10001 requires notification as soon as possible but no later than 2 business days, but the rule text does not allow for circumstances where the facility does not have knowledge of the malfunction until later. Commenter 179212 states that a source must provide a preponderance of the evidence that it has met all of the elements set forth in 63.10001 but in many cases the best a facility can practically do is prepare a best estimate.

Commenter 17772 states that the 2-day statute of limitations on AD is an arbitrarily short deadline and should be struck in its entirety. Commenter 17772 states that the accused should retain its right to defend itself against a notice of violation (NOV) and relevant evidence of a malfunction should not be ignored due to a procedural rule. Commenter 17772 cites an example where emissions are measured by a sorbent trap and the malfunction may not be found until the trap is removed and analyzed.

Commenter 17772 states that for short-term malfunctions, it may not be known until the end of the 30-day period that there has been a violation, and a better approach would be to permit the claim to be made as soon as there is knowledge of the malfunction but no later than 45-days following the event.

Response to Comment 57: The EPA is revising the notification requirement so that it reads " The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall 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 whether 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, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction."

d. Reporting method.

Comment 58: Commenter 17722 states that language in section 63.10001(b) should include "or delegated authority, as applicable" in addition to "notify the EPA Administrator..." and should replace "by phone or facsimile..." with "in an appropriate manner such as phone, fax, email, or other electronic means, as determined by the EPA Administrator or delegated authority."

Commenter 18034 states that electronic reporting, such as complies with CROMERR standards, should be allowed for the initial notifications, rather than telephone notifications, which should not be allowed, because telephone notifications are difficult to verify and enforce. Commenter 18034 states that electronic notification provides quick and durable reporting that may be relied on for investigative and enforcement purposes.

Commenter 18034 suggests that the EPA allow state rules for AD that are EPA-approved as part of a SIP, to be used in lieu of the federal procedures, to eliminate duplicative or conflicting requirements for both state agencies and regulated entities. Commenter 18034 states that TAC includes reporting of upsets (malfunctions), startups, and shutdowns, that are substantially the same as the EPA's rule. Commenter 18034 requests that as part of the alternative EPA-approved SIP procedures, consideration may be given to Texas criteria regarding the percentage of total annual operating hours for emission events in lieu of frequency.

Response to Comment 58: The definitions in part 63.2 Part 63 defines "Administrator" to mean the Administrator or authorized representative (e.g. delegated state). 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 of the exceedance. However, the written reports required to demonstrate that the affirmative defense provisions have been met and requests for an extension of the deadline for these reports may be submitted electronically.

Pursuant to EPA regulations at 40 CFR 63.93, states may seek approval of state requirements to substitute for requirements included in final section 112 standards if the state requirements are equivalent to the promulgated section 112 standards. States that have SIP approved affirmative defense provisions may seek to have those programs apply in lieu of the affirmative defense provisions applicable to malfunction periods in the final rule.

e. Not require Root Cause Analysis for every malfunction.

Comment 59: Commenter 17923 states that documentation required to assert an AD will impose administrative burden with no environmental benefit. Commenter 17923 states that a facility should not be required to conduct a root cause analysis (RCA) for every malfunction for AD. Commenter 17923 states that the ambiguity of the recordkeeping requirements limits confidence in a facility's ability to demonstrate compliance.

Commenter 17851 notes that the rule language assumes that all malfunctions are equally significant and need an identical degree of investigation. Commenter 17851 notes that a RCA implies a formal process, and believes a formal RCA should be used only when other reasonable methods fail to show what caused the malfunction or when the serious nature of an event might make such an analysis necessary. Commenter 17851 believes a RCA for every malfunction is unnecessary and requires excess efforts with no environmental gain. Commenter 17851 states that other tools may be more appropriate (e.g., failure mode and effect, fault tree, etc.) or more powerful tools may be introduced in the future, and the facility should decide which tool to use. Commenter 17851 suggests the EPA use an alternative term that does not carry a specific meaning.

Commenter 19040 states that RCA is just one of many types of inductive analyses, and other inductive techniques should be considered appropriate are the "parts count" approach, FEMA, FMECA, PHA, FHA, DFM, or RDB. Commenter 19040 also suggests that deductive methods of analysis, such as fault tree analysis, would be appropriate. Commenter 19040 suggests that the EPA not limit the analysis technique, the EPA should allow the entity to use the technique that will give the most appropriate results or conclusions. Commenter 19040 states it is in the interest of the EPA to obtain the most meaningful results or conclusions on malfunction causes, not to have facilities develop proficiency in conducting RCA and not identify the malfunction cause.

Response to Comment 59: The EPA believes that a minor administrative burden will result in sources analyzing their violative emissions to reduce or avoid those emissions in the future, which is an environmental benefit. A root cause analysis is only required if a source seeks to assert an affirmative defense. However, such an analysis is beneficial in resolving or preventing violations and excess emissions whether the source seeks to assert the affirmative defense or not. A root cause analysis is one example of what constitutes good air pollution control practices to minimize emissions.

A root cause analysis is not required for every malfunction - - only those malfunctions for which the source chooses to assert an affirmative defense. We agree with the commenter that not every malfunction is so significant that it would require asserting an affirmative defense. The EPA believes that sources seeking to minimize emissions will endeavor to find out what went wrong anytime there is a minor or major malfunction. The facility should decide what level of investigation is needed in each instance. We agree with the commenter that sources should use appropriate techniques of analysis to achieve the desired results and conclusions in the event of a malfunction. The EPA joins the commenter in seeking meaningful results which successfully identify, and address the cause of the malfunction. However, if the malfunction rises to the level of one that the source seeks to avail themselves of the affirmative defense, then a root cause analysis is required.

In the context of part 63 section 112, the term "root cause analysis" was used generically to imply an analysis of sufficient depth and complexity to indicate whether a malfunction did indeed cause a failure to meet a standard, provide sufficient information on the nature and causes of a malfunction to determine whether the source had a malfunction that met the definition of a malfunction, and whether civil penalties are an appropriate sanction for the violation, if one occurred. The term "root cause analysis" is not defined in subpart A (the General Provisions) or in the subpart being promulgated, Subpart UUUUU. The EPA did not intend to prescribe a specific methodology, given that "root cause analysis" is not a defined term in the applicable subparts of Part 63.

8. SSM limits should be more stringent; emissions are high during SS events.

Comment 60: Commenter 17975 states the EPA has not factored SSM emissions into the standards, and the EPA has not evaluated what monitoring can be done or what can be done to limit SSM emissions. Based on EGUs in Texas that have recently submitted permit applications for PM during SSM, Commenter 17975 notes that emission rates for SSM events range from 0.375 to 5.5 lb/MMBtu, which is 12 to 180 times the 0.03 lb/MMBtu limit set for non-g metals. Commenter 17975 states that facilities have requested SSM durations of 48 hours at a time and for up to 600 hours per year, and Title V monitoring reports for 2009 and 2010 for these same facilities show actual duration of SSM events frequently exceed 100 hr/yr, and more than 200 hr/yr at one facility.

Commenter 17755 states that a majority of PM and opacity excess emissions occur during SSM when the ESP is not operating.

Commenter 17975states that total PM emissions during SSM events can be 20 times higher than during normal operations and cited Texas EGUs with PM limits of 216 lb/hr that show 4,788 lb/hr for startup/shutdown, so that now their annual PM emissions that are currently 946 ton/yr per boiler could emit up to 1,436.4 ton/yr per boiler if the SSM application is granted. Commenter 17975 highlights another facility with current emissions limit of 1,033 ton/yr that could emit up to 2,284.4 ton/yr if the SSM application is granted. Commenter 17975 notes the SSM emission limits requested in the Texas applications are high and may jeopardize compliance with the EPA's non-Hg metal standard. The commenter presents an example where they assume SSM periods at 24 hours duration, incorporates these higher emission levels into the 30-day rolling average, and shows that the emissions range from 0.034 to 0.053 lb/MMBtu, which is far above the standard of 0.03 lb/MMBtu. Commenter 17975 states that 24 hours of SSM periods would also increase total non-Hg metals to 43 and 47 lb/TBtu for the 30-day rolling average, which is above the standard of 40 lb/TBtu. The commenter also notes that the opacity exceedances from SSM events exceed 24 hours, so the emissions would be even higher.

Commenter 17975 states that opacity data, which is a primary indicator of PM emissions, at EGUs in other states indicate high PM emissions during SSM events. The commenter cites an Oklahoma facility with 167.1 hr of opacity exceedances per year, and four other facilities with over 40 hours of opacity exceedances per year due to startup/shutdown. The commenter notes that these estimates are conservative since they do not include opacity spikes due to maintenance events during normal boiler operation. Commenter 17975 further notes that these exceedances can be extreme, and cited facilities with 80 percent opacity for 25 hours.

Commenter 17755 states that their inspectors have documented significant particulate emissions from COMS data during SSM and offline periods when the boiler may or may not be combusting, with greater than 400 hours per quarter for some units.

Commenter 17975 states available PM emissions and opacity data suggest that plants would have to average 10 percent opacity to achieve 0.03 lb/MMBtu PM, however opacity during startup and shutdown can be much higher, at 60 percent opacity or higher for several hours. Commenter 17975 notes that EPRI data shows PM levels of 0.06 lb/MMBtu with opacity of 15 percent; PM of 0.23 lb/MMBtu with opacity of 25 percent. Commenter 17975 indicates there is not much data relating PM emissions to extremely high opacity events, but cited data from a Georgia facility that measured 1 lb/MMBtu with opacity at 60 percent, which is 30 times higher than EPA's standard.

Commenter 17975 has reviewed SSM applications in Texas and opacity data from 2009 and 2010 from the same plants and states that SSM emissions may be even higher than the facilities have estimated. The commenter indicates that emission calculations assume 30 to 80 percent of fine PM are removed even when the ESP is not operating, because a fraction of fly ash sinks to the bottom of the APCD, however it is likely that heavier particles would drop out but smaller PM is more likely to be emitted. The commenter notes that the SSM application for one facility shows maximum emissions estimates during startup based on heat rate no greater than 693.84 MMBtu/hr, however Title V monitoring reports for the facility show opacity exceedances at startup of 80 percent or more at much higher heat rates than those shown as maximums in the application, for example, an opacity exceedance of 93 percent at over 2,500 MMBtu/hr heat input. The commenter states that these much higher heat rates for startup suggest the emissions can sometimes be much higher than estimated in SSM applications.

Commenter 17975 states that many ESPs are not turned on during startup/shutdown because they require minimum temperature for safe operation and they cannot function effectively until certain inlet gas temperature and flow rates are reached. The commenter indicates that ESPs are not turned on while coal is burned for extended period of time during startup and in the final hours of shutdown.

Commenter 17975 states it is common for ESPs not to be energized until proper operation conditions occur, and it is clear that permits do not contain limits to minimize startup and shutdown periods of ESP non-operation. The commenter states PM emissions and opacity are high during these time periods. The commenter states that high opacity during SSM time periods indicates high PM emissions, and while no uniform correlation has been developed between opacity and PM emissions, one can reasonably conclude that periods of high opacity during SSM are periods when PM and non-Hg metal emissions are high. Commenter 17975 provides examples of opacity and PM data for coal-fired units (see Table X in EPA-HQ-OAR-2009-0234-17975).

Commenter 17975 states that during startup/shutdown, baghouses can operate at lower temperatures, may not need to be bypassed at all, and could be bypassed for a much shorter period during startup.

Commenter 17722 states that baghouses do need to be bypassed during startup with fuel oil, as fuel oil negatively impacts the bags.

Commenter 17957 states the EPA must evaluate maximum control technologies that are most efficient in reducing SSM emissions and use the evaluation to set appropriate limits. The commenter indicates that high PM and non-Hg metal emissions are the result of decisions by some EGUs to continue to rely on ESPs that are not designed to function during startup/shutdown, or because EGUs have chosen not to explore other alternatives for reducing SSM emissions. Commenter 17975 notes baghouses are more effective during normal operating conditions, giving units a greater margin to accommodate upsets and still stay in compliance with 30-day averaging period. Because more than 30 percent of EGUs are controlled with baghouses, Commenter 17975 states that if MACT standards are based on the most effective fabric filters as the law requires, SSM emissions would be greatly reduced.

Commenter 17975 states that while the EPA acknowledges that MACT standards must apply at all times, that does not mean weakening a proposed standard to accommodate SSM, by lengthening the averaging time for compliance, or treating these episodes as immovable objects, when technologies that can reduce emission are proven and commercially available.

Commenter 17975 states there are best management practices to reduce emissions during SSM periods, including: new and existing units should be equipped with baghouse (instead of ESPs) to reduce emission of PM, including fine PM and thus metal HAP; natural gas should be used as startup fuel, given that it is available, reduces startup emissions, is not technically challenging, and has modest cost;

and the duration of SSM events should be kept to a minimum by defining process conditions that denote the start and end of the event in enforceable permit conditions.

Commenter 17975 notes that monitoring of non-Hg metals is not required during SSM. The commenter notes that the monitoring methods identified in the proposal fall far short of what is need to calculated emissions when boilers are brought down for maintenance and restarted after that work is complete. The commenter indicates that stack testing is conducted during "normal" operation and testing is not required to assure compliance during SSM, when emissions are likely to be highest. Commenter 17975 states that absent the evaluation of SSM events and methods to reduce their frequency and severity, as 30-day rolling average designed to accommodate SSM events is an arbitrary standard.

Commenter 17975 notes that deslagging of units as part of maintenance contributes to increased opacity even though the unit is not operating. The commenter indicates baghouses can remove deslagging PM far more effectively than ESPs, which would not be energized when the unit is off and when deslagging occurs.

Commenter 17975 provides examples of drop-out factors used for ESPs to estimate PM emissions during startup and shutdown, where even though the ESP is non-operational or non-energized, the collection efficiency is not zero.

Response to Comment 60: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. These work practice standards take into account operation of APCDs. See the preamble and rule for discussion and requirements. The EPA's rationale for its approach to malfunctions is discussed in the preamble.

We note that sources that install CEMS or other continuous monitoring devices are required to operate them at all times. Section 63.10020 clearly states that if you are conducting continuous monitoring, "You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating…" We believe that it is important to collect data during all process operating periods including SSM periods, as the rule requires when conducting any continuous monitoring (see additional responses above relative to the accuracy and utility of such data). The Agency also believes EGU owners or operators strive to minimize periods of malfunction and should a malfunction period occur, its duration will be brief, as noted by the commenter. Any impact of potential excess emissions occurring during a period of malfunction would be offset through use of the rule's 30 boiler operating day rolling average requirement. To the extent the CEMS records an exceedance during a malfunction, and the owner or operator believes the measurement was in error, the owner or operator can demonstrate that the source complied with the standard notwithstanding the CEMS measurement using any available information.

Commenter's inference that PM emissions during startup may be up to 20 times higher than during is based on permit information and emissions estimations rather than emissions data. Further, commenter does not provide HAP data for such periods. We believe that our approach will provide the data necessary to evaluate these emissions during the 8-year review.

9. Use of multi-metals CEMS and fuel testing for startup fuels.

Comment 61: Commenter 17283 states that use of a multi-metal CEMS allows monitoring of all urban HAP metals, including Hg and all phases. Commenter 17283 indicates that multi-metal CEMS have lower initial and on-going costs than the EPA's option of monitoring with two CEMS, and multi-metal

CEMS use allows monitoring of emissions directly, so it is not necessary to conduct performance testing for individual metals.

Commenter 17675 supports the exemption from fuel testing for startup fuels.

Response to Comment 61: For the use of multi-metals CEMS, please see the response to all comments under Comment Code 5A07b. The exemption for startup fuels is no longer applicable as the proposed fuel testing requirements are not part of the final rule.

10. Initial startup.

Comment 62: Commenter 17801 states that neither MACT or NSPS limits should apply during the initial startup of a facility, should not apply until after the EGU has achieved its Commercial Operation Date (CCD), or at the earliest, per 40 CFR 60 General Provisions, 60.8 for a performance test demonstration compliance period that allows up to 180 days after initial commissioning operation. Commenter 17801 states that the EPA could establish different limits based on initial startup and commissioning conditions and activities.

Response to Comment 62: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits, and compliance with the work practice at initial startup should not be an issue for sources. Further, commenters have not explained under what authority EPA would allow a source to not comply with the final rule on the compliance date of the final rule; therefore, we are not providing the provision suggested by the commenters.

11. Initial data.

Comment 63: Commenter 17402 states that the EPA cannot establish that the proposed numeric emission limits represent a reasonable estimate of emissions achieved by the best performers during startup and shutdown as required by the CAA and the courts in Cement Kiln Recycling Coalition. Commenter states that, as a result, the EPA must establish work practice standards for these periods.

Comment 64: Commenter 17776 states that the proposed rule would inappropriately require EGU's to comply with numeric MACT standards during startups and shutdowns even though the agency did not consider data for startup and shutdown in developing the standards. The proposal is therefore arbitrary and capricious because the agency relies on inaccurate or unfounded assumptions about such events. Commenter 17776-11 states that the EPA assumes incorrectly and without adequate basis that startup and shutdown are predictable and routine, that a 30-day averaging period will accommodate startups and shutdowns, and that emissions during these periods can be accurately calculated. Commenter 17776-11 states that many outages are unavoidable and unplanned with the effect that the 30-day averaging time is not adequate given the frequency of outages.

Comment 65: Regarding startups and shutdowns, commenter 17914 cites the following as problems with the EPA's MACT floor analysis:

- No startup/shutdown data were considered.
- Incorrectly characterized solid fuel-fired EGUs as infrequently starting up and shutting down and using cleaner fuels during startup.
- Incorrectly characterize startups and shutdowns as predictable and routine.

- Limited PM monitor data indicates an order of magnitude higher emissions during startup and shutdown than during normal operation.

Commenter 17914 recommends that the agency collect a minimum of 30 days of continuous emissions data, including periods of startup and shutdown, from the top performers and use the data to set the standard.

Comment 66: Commenter 18034 states that emissions during startup and shutdown were not evaluated for the proposed emission limits and that the EPA should establish work practices for these periods. Commenter 18034 states that the boiler MACT rule requires work practices in lieu of numerical limits for periods of startup and shutdown.

Response to Comments 63 - 66: The EPA acknowledges that it does not have data upon which to base numerical emission limits during periods of startup and shutdown. Therefore, the EPA is, in the final rule, establishing work practice standards for periods of startup and shutdown. In addition, the EPA is committing to reevaluating this approach during the 8-year review when sufficient CEMS data will be available from the EGU population.

Comment 67: In commenting that the EPA is not adequately addressing emissions during startup, shutdown and maintenance, commenter 17975-15 states that opacity exceeded 80 percent during at least 44 hours at Gibson boiler 2 in 2009 after boilers were turned off for maintenance. Commenter 17975-30 provides data showing PM emissions of 0.03 to 0.050 lb/MMBtu at opacities of 10 to 11 percent, which implies that opacities greater than these correspond to PM emissions greater than the proposed 0.03 lb/MMBtu.

Response to Comment 67: Commenter has not provided data to indicate the impact of these periods of high opacity on HAP emissions. Further, commenter has not provided, and the EPA does not have, data on HAP emissions during periods of startup and shutdown. In addition, it is not clear what commenter is suggesting the EPA do with this information or how we could incorporate it into the MACT standard setting process. In the final rule, the EPA has specified work practice standards for periods of startup and shutdown. See the preamble for discussion.

12. Other.

Comment 68: Commenter 17402 opposes the application of the numeric emission limits established for steady state operations to sources during periods of startup and shutdown. Commenter states that as a result of the technical infeasibility of measuring emissions and the impracticability of enforcing numeric emissions limits during those times, the statutory requirements for the EPA's authority to impose a work practice standard are met. The EPA should, therefore, abandon its approach to enforcing identical numeric emissions limits during startup and shutdown and, instead, adopt a work practice standard consistent with its own precedent in the Industrial Boiler MACT rule.

The commenter states that even with the proposed 30 boiler operating day averages, emissions from these non-representative periods could significantly affect the averages, especially for peaking units or other units that com on- and off-line frequently. Commenter agrees with the EPA that startup and shutdown periods are of short duration in relation to the long-term operation of control equipment, but it is important to note that to maintain the efficiency of control equipment, they must be run in a certain way during periods of startup and shutdown. The EPA ignores what is well known–emissions control devices typically perform less than optimally during periods of startup and shutdown. In fact, some air pollution control equipment cannot be operated at all when the boiler is starting up. Commenter provides examples of how control device operation and efficiency are affected during startup and shutdown and by the procedures followed to bring pollution control equipment online. In the commenter's experience, sources controlled using ESP will necessarily have higher Hg emissions during the first 24 hours after startup especially for plants using ACI to control Hg from subbituminous coal, which cannot be readily controlled with other technologies. Commenter states that the numeric emissions limitations established for periods of steady state operations should not be applied to periods of startup and shutdown when controls are not performing at optimal levels (or are not performing at all until certain temperatures are reached).

Several commenters (17681, 17714, 17758) also support work practice standards for startup and shutdown events. Commenters note that work practice standards are consistent with the CAA and has been done in other MACT rules, such as the industrial boiler MACT rule.

Response to Comment 68: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. See the preamble and rule for discussion and requirements. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action.

Comment 69: According to commenter 17402, the EPA argument for not setting emission limits for malfunctions - that it would be difficult to apply the concept of best performing to a malfunctioning unit and that it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for EGUs - actually argues in favor of the EPA setting a work practice standard as an emissions standard for malfunction events rather than the numerical emission limits. Commenter opposes the EPA's proposal to use its discretion to determine an appropriate response in the event of a malfunction and it opposes the EPA's affirmative defense proposal. Commenter states that under their current title V operating permit applications, they have established a state-approved plan, which minimizes malfunction events and requires best practices be followed, that it follows during malfunctions and breakdowns, which is preferable to the EPA's proposal in which there is a presumption of non-compliance and is focused on after-the-fact penalty. Furthermore, the EPA's approach would add yet another burden on the states at a time when states are working with increasingly limited resources and are already overburdened with regulatory responsibilities. Since it would not be technically feasible to accurately measure emissions and impracticable to enforce numeric emissions limits during malfunction and breakdown (for either stack testing or CEM monitoring, which would not have the ranges required to have accurate data), the statutory requirements for the EPA's authority to impose a work practice standard are met and the EPA should abandon its approach to enforcing identical numeric emissions limits during malfunction and breakdown and, instead, adopt a work practice standard.

Response to Comment 69: The EPA's rationale for its approach to malfunctions is discussed in the preamble. As explained in those preambles, the EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. As the EPA further explained, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. The EPA's rationale for its approach to malfunctions is not based on the criteria that must be met to justify a work practice standard under CAA section 112(h). Further, setting work practice standards under section 112 presents the same issues as setting numerical emission limits given the varied nature of malfunctions. In any event, commenter has not provided support for its assertion that it would not be technically feasible to accurately measure emissions and impracticable to enforce numeric emissions limits during malfunction and breakdown. Sources in this category can and do operate multiple measurement systems that measure different parameters at different points in the generating process and on affected sources and control equipment. While direct measurement of some factors may or may not take place during certain malfunctions, the EPA is not persuaded that sources could be left with no means whatsoever to determine whether they stayed in compliance during a malfunction. Sources may use other available means (including engineering judgment) or information to demonstrate that the source complied with the standard.

With respect to commenters claim that the affirmative defense will burden the state, many of the conditions of the affirmative defense 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 states have had any significant difficulties applying or implementing the terms of these SIP affirmative defenses.

Comment 70: Commenter 18539 recommends that a startup, shutdown and malfunction plan that is incorporated into a unit's title V permit is an appropriate work practice standard for startup, shutdown and malfunction. Commenter 17402 recommends that the EPA adopt a requirement that a unit must submit an SSM plan for approval and incorporation by reference into its title V operating permit as the work practice standard for periods of startup, shutdown and malfunction. According to the commenter, such as approach would ensure that units minimize SSM periods and that appropriate operating practices are followed during these periods and, thus, would result in minimizing emissions.

If the EPA does not adopt a work practice standard for periods of startup and shutdown, the commenter requests, in the alternative, that the emission averaging period be increased to a rolling 12-month average time period as opposed to the proposed 30-day rolling average. In this way, the increased emissions from periods of SSM would be spread out over a longer averaging period, and the EPA could potentially show that the limits were achievable even during SSM events.

Commenter 17776 likewise believes that a more stringent approach for startup and shutdown emissions is not necessary for some types of boilers and encourages the EPA to require compliance with work practice standards for EGUs as in the Boiler MACT. Failing that, the commenter suggests that the EPA set special MACT standards for startup and shutdown periods at EGUs based on a reasoned analysis of data concerning such emissions.

Commenters 17790 and 17851 find the EPA's logic about applying the proposed standards during startup and shutdown to be flawed because it does not account for the variety of ways in which the EGUs startup and shutdown and because it is not based on actual emissions during those occurrences. Commenters point out that PM CEMS are not correlated during periods of startup and shutdown because the EPA requires full-load operation for CEMs certification testing and the EPA manual test methods are not designed for transient plant operations. Therefore, Commenters request a separate work practice standard for use during periods of EGU start-up and shutdown. Commenter 17914 agrees with this suggestion.

Commenter 18037 recommends that the EPA adopt a work practice standard in lieu of numeric emissions limitations during periods of startup, shutdown, malfunction and breakdown. The operational efficiency of control equipment is critical to emissions reduction and these controls must be run in a certain way during periods of startup and shutdown. The EPA's decision ignores that it is well known that emissions control devices typically perform less than optimally during periods of startup and shutdown. In fact, some air pollution control equipment cannot be operated at all when the boiler is starting up.

Response to Comment 70: For periods of startup and shutdown, the EPA is finalizing work practice standards instead of numeric emission limits. These standards take in to account operation of APCDs. See the preamble and rule for discussion and requirements. The EPA's rationale for its approach to malfunctions is discussed in the preambles to the proposed rule and this final action and elsewhere in this response to comments document. The requirements do not include a startup, shutdown, and malfunction plan. See Table 3 to Subpart UUUUU of part 63. Commenter's suggestion that its state-approved plan is prefereable to EPA's approach does not explain how an approach based on such a plan meets the requirements of section 112.

5C07 - Compliance: Other

Commenters: 16849, 16850, 17385, 17402, 17620, 17638, 17648, 17689, 17702, 17714, 17716, 17718, 17719, 17729, 17730, 17736, 17737, 17740, 17752, 17754, 17756, 17758, 17761, 17765, 17767, 17768, 17772, 17775, 17790, 17791, 17795, 17798, 17800, 17805, 17808, 17813, 17818, 17820, 17821, 17840, 17851, 17867, 17868, 17871, 17880, 17881, 17886, 17902, 17909, 17914, 17928, 17930, 18019, 18025, 18034, 18424, 18429, 18477, 18498, 18539, 18541, 18963, 19033, 19114, 19214, 19536, 19537, 19538, 18023

1. Support low emitters alternative compliance.

Comment 1: Commenter 17402 supports establishment of a low emitters alternative compliance, with modifications. Commenter 17402 states that facilities that satisfy the low emitters standards are necessarily demonstrating emissions 50 percent to 90 percent below the proposed limits, and these extremely low emissions should be encouraged with greater compliance flexibility. Commenter 17402 proposes that fuel testing only be required every 6 months. Commenter 17402 also suggests that testing be based on the reductions capability of the plant demonstrated during the test, not the particular level of emissions during the test.

Commenter 17754 states that if an affected EGU has been determined to be a LEE (for Hg), it is clear that such unit's Hg emissions are very low, and as such, these LEE units should not be subject to unduly burdensome requirements for demonstrating continuous compliance.

Commenter 17176 states the fuel sampling requirements for LEE units are ambiguous, provide no compliance value, do not require the establishment of a fuel input operating limit, do not address single-fuel units, changes in fuel type, or units that burn or co-fire multiple fuels. Consistent with the non-LEE requirements, Commenter 17176 states that LEE units that burn multiple fuel types or blends should establish a fuel-input operating limit during the initial compliance demonstration, and the EPA should remove the monthly fuel sampling requirement and allow multiple-fuel LEE units to conduct fuel sampling only when the fuel type changes. Commenter 17176 states single-fuel LEE units should not have to comply with any fuel sampling requirements.

Commenter 17754 states the EPA should revise the proposed rule regarding the use of the 90th percentile upper confidence level for determining the operating limit for mercury (LEEs for Hg). Commenter 17754 states the rule should be clarified that, while the initial performance test is conducted over a 2830 day period to demonstrate LEE status, the subsequent performance tests (performed every 5 years) shall consist of three 120-minute runs, unlike the longer duration of the initial performance test.

Commenter 17754 notes the rule should be modified because it is unclear whether a source owner/operator who demonstrates initial satisfaction with the LEE criteria, but then subsequently fails to demonstrate continuous compliance with the relevant standards, has the ability to retest the unit to reestablish its LEE status. Commenter 17754 states a source owner should be afforded the opportunity to demonstrate that an affected EGU qualifies as a LEE, notwithstanding a prior performance test result exhibiting emission rates in excess of the threshold. Commenter 17754 indicates the compliance demonstration methods under the rule provide a highly conservative estimate of Hg emission rates for purposes of ensuring LEE status, and this conservatism should not prevent such source owner from demonstrating LEE applicability by more refined analyses.

Response to Comment 1: The final preamble describes the final rule provisions for LEE. Because the proposed fuel analysis provisions are not part of the final rule, the approach to maintaining LEE status has changed. For mercury, an existing unit may qualify based on an initial Method 30B test, and then will have to retest annually. If the LEE status is lost based on the results of an annual retest, the rule requires you to install an Hg CEMS or sorbent trap monitoring system, with quarterly Method 30B testing until the monitoring system is certified. You can regain LEE status for that unit if every required performance test for a 3-year period shows that emissions from the unit did not exceed the LEE limit. For non-Hg emissions, you can qualify for LEE status if all performance tests conducted over a 3-year period meet the LEE qualification limit. In that event, you must retest every 36 months to demonstrate that you still qualify for LEE status. If any subsequent emissions test for that pollutant exhibits emissions greater than 50 percent of the emissions limit, you must revert to the original emissions testing frequency until you re-establish a 3-year period of very low emissions no greater than 50 percent of the standard.

2. Support the EGU NESHAP Rule.

Comment 2: Commenter 17648 states the EGU toxics rule will provide needed regulatory certainty and will spur investment in new generation controls. Commenter 17648 notes that today we increasingly rely on aged infrastructure that operates without pollution controls simply because the federal government has failed to establish legally enforceable emissions standards for toxic pollutants. Commenter 17648 states that the lack of a national standard for toxic emissions continues to be a barrier to investment in new, cleaner generation capacity as well as the modernization of existing sources. Commenter 17648 states companies are reluctant to build replacement, cleaner generation or to modernize existing plants when it is not assured that their competitors will be required to comply with modern emission standards, and it has been found that the installation of pollution controls will raise the marginal costs of production for those early adopters and place them at a competitive disadvantage relative to those that do not install pollution controls. Commenter 17648 states the regulatory certainty provided by the toxics rule is long overdue.

Commenter 17930 supports the EPA's decision that it was not appropriate to set numerical emissions limits for organic HAP and that a work practice standard would be more appropriate. As stated by the EPA, the majority of measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods. They cannot be reliably measured and cannot be subject to emissions limits.

Commenter 18541 states that technologies are available to achieve such reductions, and virtually eliminate some of these emissions, not only though on-site emissions reductions, but also by switching to cleaner sources of electricity generation and energy efficiency, and using improved grid system management within the relevant electricity balancing area.

Commenter 17718 supports the EPA's proposed approach to streamline the continuous compliance requirements for monitoring, reporting, and recordkeeping. The commenter states that the EPA is correct in recognizing that the compliance requirements are already applicable to EGUs and eliminating redundancy wherever possible. The commenter urges the EPA to remain open to additional accommodations that are identified in the course of implementing the program.

Commenter 19214 states that to demonstrate compliance with both the Boiler NESHAP and the EGU MACT, the more stringent emission limit should be demonstrated. The commenter states that it is the responsibility of the source to show compliance with all applicable limits. The commenter supports the EPA's proposal that compliance with the more stringent emission limit be demonstrated.

Response to Comment 2: The EPA acknowledges the support provided in these comments, and believes the final rule remains consistent with these general areas of support.

3. Performance testing.

Comment 3: Commenter 17808 states the testing requirements are very burdensome and believes the agency could achieve an equivalent level of compliance assurance with a lower compliance burden with adjustments.

Comment 4: Commenter 18023 urges the EPA to allow annual filterable PM stack testing as an alternative compliance option. Commenter 18023 notes that complying with the monthly or bi-monthly PM or non-Hg metallic HAP alternatives is not practical for the following reasons: (1) both planned and forced outages will make it difficult to obtain proper unit operating levels, which will stretch the short term capacity of the testing community nationwide; (2) it is cost prohibitive, as PM testing will cost approximately $3000 to $5000 per source per month, Hg testing via RM-30B will cost approximately $10,000 per source per month, and non-Hg metal testing via RM-29 will cost approximately $8,000 to $10,000 per source per month; (3) analytical results take a minimum of 2 weeks to be analyzed and reported by laboratories, so a unit could potentially be out of compliance for 2 weeks before analytical results could be provided; (4) analyzing this data is a difficult scientific proposition – lab technique and experience are important to avoid biasing the data; and (5) changing compliance and permit limits monthly based on new test results would place unreasonable operational restrictions on generating units in an effort to comply with a potentially moving target.

Response to Comments 3 - 4: In the final rule, the optional periodic testing has been reduced to once a quarter. Sources have the option to use CEMS or PM CPMS in lieu of compliance testing.

Comment 5: Commenter 17775 states EGUs should have flexibility to specify when performance tests for CEMS and sorbent trap monitoring systems start. Commenter 17775 notes that for CEMS or sorbent trap monitoring system, the "performance test" consists of the "first 30 operating days of data collected with the certified monitoring system." (section 63.10005(a)); section 63.10005(g) through (j) allows 180 days after the applicable compliance date to "demonstrate initial compliance;"and "performance tests" also must be conducted under specific operating conditions (section 63.10007(c)). Commenter 17775 objects to the proposed arbitrary designation of the "performance test" periods. Commenter 17775 states the start of performance tests should not be arbitrarily tied to completion of monitor certification, but instead, EGUs should be allowed to complete certification tests on monitoring systems and to use those certified systems to determine whether the shakedown of emission controls have been successful prior to conducing the "performance test" to establish compliance with emission limits. Commenter 17775 notes that EGUs also must be able to time the start of the "performance test" to ensure that it meets the fuel and operating conditions the EPA has specified. In fact, proposed section 63.10030(d), which requires submission of a "Notification of Intent" to conduct a "performance test" at least 30 days before it is scheduled to begin, suggests that sources have the ability to specify a date in advance that may be unconnected to the testing of the monitoring system.

Commenter 17775 states that allowing sources flexibility to specify at what point during the 180-day period the "performance test" starts not only makes sense, it is in some cases necessary. At a minimum, Commenter 17775 indicates the EPA needs to allow flexibility for sources to specify the start of the "performance test" for CEMS that have been previously certified (e.g., SO_2 CEMS that were previously certified under the Acid Rain Program). Commenter 17775 points out that otherwise their performance test technically could have begun prior to the compliance deadline (or even prior to this rule being promulgated). The commenter states that in addition, for PM CEMS, which do not conduct anything called "certification testing" (the term "certification" does not appear anywhere in PS 11), there is no clear point at which to declare that the performance test has begun. Unlike SO_2 CEMS, PM CEMS must be correlated by conducting tests with a reference method and developing a "correlation curve" that meets PS 11 performance criteria. According to the commenter, once the curve is developed, the PM CEMS must be programmed so that its output is adjusted consistent with that curve. The commenter states that none of these actions are consistent with the concept of a system instantly becoming a "certified" upon completion of a test. The commenter states that although sources do conduct a 7 day drift test under PS 11, that test is almost always conducted prior to any correlation testing in order to avoid having to repeat correlation testing if the 7-day test is not passed, and as a result, the drift test cannot be used to define when the PM CEMS is "certified."

Response to Comment 5: While the EPA does not share the concerns that the commenters have about relating monitoring system certification with performance testing, final rule has been revised so that 30 day test is not tied to the certification of the CEMS or sorbent trap monitoring system. In addition, as mentioned elsewhere, the requirements for the mandatory use of PS-11 have been removed from the final rule.

Comment 6: Commenter 17775 notes that the EPA must recognize that there are limitations on the conditions under which the EPA can require EGUs to test. To comply with CAA section 112, Commenter 17775 states the EPA assessed the capabilities of controls under the conditions specified in the 2010 ICR testing and established compliance testing and compliance assurance requirements consistent with that assessment. Commenter 17775 indicates the EPA has proposed continuous monitoring, initial stack testing, or periodic fuel analysis that it presumably believes are consistent with that assessment; as long as an EGU is complying with one of the options for demonstrating "continuous compliance," there is no basis to allow the Administrator to specify some other test be conducted under some other set of conditions.

Commenter 17775 agrees that EGUs should be allowed to use prior tests, however, the EPA should allow use of any tests conducted under the same conditions, even if those conditions have not remained unchanged during the entire period since the test (e.g., if there was a period between the prior test and the current compliance demonstration when a different fuel was combusted).

Commenter 17880 supports the EPA to require affected coal or oil-fired plants to conduct performance tests that demonstrate compliance with applicable emissions limits.

Commenter 17928 states that the frequency of performance tests required for organics compliance should be reduced.

Commenter 18025 asks that the EPA give consideration to units already subject to state-level testing requirements where these requirements provide at least the same assurance as the Utility Toxics Rule. The commenter notes that their Bridgeport coal unit complies with a Hg emission standard half that proposed by the EPA for similar units. The commenter states that Connecticut DEP remains confident that quarterly stack testing provides a sufficient guarantee of compliance. The commenter states that likewise, the commenter's Hudson and Mercer coal units consistently comply with New Jersey's Hg requirement through stack testing, and recent test data have shown very low levels of Hg relative to New Jersey's Hg limit of 3.00 mg/MWh (net). The commenter requests that in similar situations state requirements be accepted as alternate testing plans for the Utility Toxics Rule.

Commenter 17930 states that the EPA has proposed to require an annual performance test, which includes a "tune-up," but the EPA allows an extended period of up to 18 months "for those EGUs with unusual planned outage schedules," though there is no standard planned outage schedule across the industry. The commenter states that many coal and lignite fired units are scheduling 24-month outages; some have even longer scheduled outages. According to the commenter, in the next few years, it is expected that the schedule will be extended even more as maintenance practices improve and as consumer electricity demands, and demands for base load capacity, increase. Therefore, Commenter requests that the final rule provide the option for performance tests and tune-ups to be conducted on the existing schedule of each power plant. The commenter states that in the event that the EPA feels there must be a maximum time limit, it cannot be shorter than 36 months without significantly interfering with plant operations.

Response to Comment 6: In response to comments, EPA has reduced the duplicative testing of fuels, HAP surrogates and HAP. Optional periodic testing frequency has also been reduced. The EPA disagrees with the adoption of various state Hg rules within the final MACT rule. Sources may apply on a site specific basis for alternative monitoring per 63.8. Neither the proposed rule nor the final rule required organic HAP compliance testing, so there is no frequency to be changed. The tune-up work practice and testing has been altered to allow for more flexibility for facilities with less frequent outage schedules.

Comment 7: Commenter 17775 states that the purpose of section 63.10005(d)(7) "(demonstrate initial compliance through CPMS)" is unclear. Commenter 17775 is not aware of any option in the rule to demonstrate compliance using CPMS that measure pollutant concentration. Commenter 17775 states the EPA should issue a proposal that explains the purpose of this provision so that they can provide meaningful comment on it.

Response to Comment 7: The commenter is correct that there was no option for initial compliance option for use of CPMS in the proposed rule and this was an erratum.

4. Frequent testing for liquid oil-fired units.

Comment 8: Commenter 17758 states that frequent performance stack testing (monthly or every other month) for oil-fired EGUs is impractical, unnecessary, restrictive, and expensive, and notes these units would have to brought on-line just for the sake of performing the stack tests. Commenter 17758 states that liquid oil-fired EGUs should perform stack testing no more frequently than annually.

Commenter 17775 states that for section 63.10006(l) and (m) for liquid oil-fired EGUs without HCl and HF CEMS", the EPA must make it clear that the HCl and HF testing requirements do not apply to EGUs using fuel analysis in lieu of performance testing, and that fuel analysis is an alternative to performance testing.

Commenter 17928 requests that the hours for mandatory unit testing should not be included in the calculation of oil use. These tests required by the ISO or for compliance with the proposed rule should be exempt from any "limited use" calculation.

Commenter 17716 states that many liquid oil-fired sources operate infrequently and only during peak demand periods, and frequent performance testing (monthly or every other month depending on whether add-on controls are installed) is burden. Commenter 17716 further notes that no correlation was found between the PM control at oil-fired units and non-Hg metallic HAP emissions, that the emissions of HCl, HF, and non-Hg metals are most closely tied to fuel characteristics, and that changes in fuel characteristics over time could be tracked to determine if a change in emissions is likely. Commenter 17716 states the fuel sampling, analysis, and calculation of expected emission rates are already incorporated in section 63.10021 and should be applied for liquid oil-fired sources.

Response to Comment 8: Under the final rule, liquid oil-fired units have three basic options for monitoring compliance, with a third alternate a possibility in some situations. First, these units may conduct quarterly performance tests to demonstrate ongoing compliance. If they choose this option, they must also conduct site-specific monitoring to ensure compliance between tests (see the final preamble for further discussion). Second, sources may use CMS for various pollutants. This includes the use of a PM CPMS to demonstrate compliance with an operating limit established during an initial performance test that demonstrates compliance with a filterable PM, total HAP metals, or individual HAP metals emission limits. A source can also elect to use a PM CEMS as a direct compliance method with the filterable PM standard (see the preamble for further discussion of this option). It also includes the use of an HCl/HF CEMS for acid gas compliance demonstrations. The third alternative is for fuel moisture monitoring. This compliance option allows you to monitor fuel moisture (either through direct sampling of fuel you receive or through fuel supplier certification). Provided that the fuel moisture is no greater than 1.0 percent, the rule states that you are in compliance with the HCl and HF emission limits. If results indicate moisture above 1.0 percent, you must institute one of the other options for monitoring compliance with the HCl and HF limits. With respect to the comment concerning the need for HCl/HF CEMS performance specifications, please see the responses to comments under Comment Code 5A09.

5. Operating limits.

Comment 9: Commenter 18023 suggests BLDS for fabric filters are not necessary, and if BLDS are required in the final rule they should only be used for purposes of triggering maintenance activities. Commenter 18023 explains the following for BLDS: (1) this operating limit is purely arbitrary, the EPA provides no information nor makes any claim that the operating limit quantifiably connected to the HAP emission limit; (2) the preamble language provides a different requirement where the output of the BLDS is measured during performance testing and then becomes a BLDS operating limit, this is an improper use of the BLDS as it attempts to use the system to quantify emission rates; (3) the EPA guidance document on Fabric Filter Bag Leak Detection Guidance states, “this guidance is not intended to evaluate changes in the long term performance of the baghouse system, nor does it apply to applications in which monitoring system attempts to quantify emission rates” (EPA-454/R-98-015 September 1997); (4) the BLDS is more appropriately used to trigger maintenance activity rather than being used to determine compliance; and (5) bag failures are not acute occurrences and could be adequately identified in the bi-monthly performance test required by the MACT.

Comment 10: Commenter 18023 suggests setting fixed secondary power input limits for ESPs is unnecessary, and if the EPA goes forward setting ESP operating limits, the only necessary requirement should be to ensure that ESP power supplies remain in service. Commenter 18023 explains the following: (1) ESPs are generally designed to meet a specified performance level with one or more TR sets out of service, this provides operational margin for malfunction and/or maintenance of each TR set, a boiler operator would have to perform its compliance test with secondary power artificially reduced in order to maintain this margin, and this seems to contradict the EPA’s desire to acquire meaningful emission data; (2) process conditions beyond the control of the boiler operator such as flue gas temperature, fly ash resistivity, and grain loading can affect the power levels of the ESP without necessarily detrimentally impacting emissions, some margin should be added to the operating limit to account for this variability (*i.e.*, within 20 percent of the lowest 1-hour average secondary power); (3) because performance does not correlate perfectly with ESP secondary power, a reduction in power is more appropriately used to trigger maintenance activity (*i.e.*, returning a TR set to operation) rather than being used to determine compliance; and (4) it is unclear why the proposed operating limits only apply for EGUs that operate additional wet control systems, the EPA should clarify what requirements they are proposing for EGUs that operate only an ESP.

Response to Comments 9 - 10: The EPA has responded to similar comments under Comment Codes 5A05 and 5A05a. Please see those responses. Under the final rule, there are no operating limits for control device parameters or any BLDS requirements.

6. Support flexible compliance options.

Comment 11: Commenter 16850 states that electric utilities should be given the flexibility to choose the most efficient, least-cost compliance options to meet public health and environmental goals.

Commenter 17648 notes the EPA has provided a variety of compliance options, particularly notes that the EPA provided a flexible array of compliance options for both initial and continuing compliance demonstrations, and encouraged the installation and use of CEMS but has not mandated CEMS, thus giving sources reasonable opportunity to design different compliance programs that best align with the source's short- and long-term plans.

Commenters 17730 and 17820 appreciate that there are several compliance options in the EGU MACT rule, and states that electric utility industry will need flexibility to achieve compliance with the requirements.

Comment 12: Commenter 17736 requests that the EPA revise the emissions limitations to reflect the inherent operational variability of coal-fired EGUs and provide sources with greater flexibility to demonstrate compliance. According to the commenter, the EPA must give practical consideration as to how coal-fired EGUs operate. The commenter states that the combustion technologies for coal-based units drive the selection of emissions controls, such as wet versus dry flue gas desulfurization.

Comment 13: Commenter 17772 states that the proposed rules purportedly leave in place the existing emission standards for SO_2, NO_X, and PM as applied under Part 60, subpart Da to existing EGUs. The commenter states that the compliance provisions as proposed in the HAP regulations, Part 63, to include all emissions even during periods of SSM makes no adjustments to the currently-effective emissions levels but makes those levels more difficult to achieve for an existing EGU that is reconstructed or merely modified, by eliminating the existing SSM exclusions. Commenter recommends that the EPA reconsider incorporating these SSM exclusions.

Comment 14: Commenter 17791 requests that the EPA recognize the needs of states and regions to deploy a diverse portfolio of cost-effective supply-side and demand-side resources based on the unique circumstances of each State and region.

Commenter 18539 states that the EPA takes steps to provide critical flexibility by providing for the use of surrogates to demonstrate compliance, proposing work practice standards where appropriate and allowing for emissions averaging. The commenter states that the EPA diminishes the utility of these flexibility mechanisms-consequently driving up costs and complexity-by placing burdensome and unnecessary restrictions and requirements on them, without demonstration of substantial environmental or health benefits and that the EPA's proposed compliance testing and monitoring programs are complicated, confusing and costly, without any demonstration as to why the requirements are necessary or how they would ensure compliance over the long term even among the existing top 12% MACT pace setters.

Commenter 19114 asks for greater flexibility so sources can reliably demonstrate compliance, such as through reexamination of the sources of uncertainty and recalculation of the limits, longer averaging times, additional options for averaging with other units, as well as development of work practice standards for known periods when controls do not operate, such as start-ups and shutdowns, or design of emission rates that can actually be achieved across the whole range of operations a unit would experience. The commenter states that the EPA should consider the full range of operating conditions that might be expected over the life of a unit in establishing the final rule. The commenter is concerned that there is a risk of non-compliance due to unknown and uncontrollable variables, especially for elements present in trace quantities for which no detailed operational history exists, is significantly increased. According to the commenter, state agencies have designed permits with limits or work practice standards that are applicable to specific coal types and/or operating scenarios. The commenter states that in many cases, permits have been designed that exempt specific operating conditions, such as startup, shutdown, and malfunction operations, from the emission limits designed for normal operations. According to the commenter, particularly in the case of EGUs where control equipment is subject to known operational limits (like safe operating temperatures in the flue gas before electrostatic precipitators can be energized or ammonia injection for a selective catalytic converter can commence) the case for the development of work practice standards is strong. The commenter asserts that the EPA's proposed limits do not provide sufficient flexibility to allow compliance demonstrations to be made during reasonably foreseeable operating scenarios and must be reevaluated.

Comment 15: Commenter 16849 supports the need for at least a 180-day period to perform all compliance testing including needed adjustments and repairs to Hg CEMS.

Commenter 17928 states that compliance requirements that are based on calendar months or calendar quarters, rather than on operating quarters or years, could lead to unnecessary operation solely to demonstrate compliance, which is undesirable from both an environmental and a financial perspective.

Response to Comments 11 - 15: We address comments related to the compliance time and startup/shutdown/malfunction in the preamble to the final rule and elsewhere in this RTC. With regard to the flexibility comments, we believe that we have provided the flexibility reasonably allowed under the statute and court precedent. As noted elsewhere in this document, we have made adjustments to the monitoring provisions of the final rule that we believe will reduce the burden and complexity while complying with the statute.

The rule increases the emissions monitoring, reporting, recordkeeping, and testing options available to EGU owners or operators by adding additional choices, each of which has an averaging time that assures compliance with emissions limits. The rule no longer contains emissions limits but work practice standards, including operation of emissions control devices as appropriate, during periods of startup or shutdown and does not impede development and deployment of diverse energy portfolios. Compliance options have been simplified, but still assure compliance with emissions limits. While the Agency finds no impediment concerning averaging periods based on calendar months or EGU operation, the rule affords liquid oil-fired EGUs whose annual capacity factor is less than 8 percent the ability to meet a work practice standard, rather than conduct emissions testing, thus preventing the commenter's concern about unnecessary operation solely to demonstrate compliance.

7. Clarifications needed for compliance demonstration.

Comment 16: Commenter 17752 states that the compliance demonstrations require clarification and revision. Commenter 17752 notes that although the EPA provides a number of compliance demonstration options, the applicability of many requirements is unclear. Commenters (17752, 17775) state the EPA must revise the proposal to clarify what requirements apply to each compliance option and include supporting rationale for each requirement. Commenter 17752 notes the preamble has inconsistent statements and lacks rational as to when operating limits and fuel input limits apply and when they do not apply (citing IV. Summary of this proposed NESHAP Section I. What are the testing requirements? Section J. What are the continuous compliance requirements? Section K. How did we select the compliance requirements? and V. Rationale for this proposed NESHAP). Commenter 17752 cannot think of any rationale as to why a source with a continuous monitor would also need to comply with an operating limit, and the commenter believes that the EPA intends for the operating limits and fuel input limits (including the operating load limit and continuous parameter monitoring systems) to only apply to EGUs who do not use continuous monitors to demonstrate compliance. Commenter 17752 states that if this is not the case, the EPA needs to include rationale for requiring the operating limits and provide an opportunity for public comment on the rationale.

Commenter 17775 states these proposed provisions in section 63.10011(b) suggest that some EGUs, i.e., those that demonstrate compliance using "performance testing," will need to establish operating limits and maximum fuel pollutant input levels, and those that do not use "performance testing," will not have to establish those. However, Commenter 17775 notes that this supposed distinction between EGUs that demonstrate compliance using "performance testing," and those that do not, does not exist elsewhere in the rule (or in the Part 63 general provisions); for example, proposed section 63.10000(c)(1) and (2) require "performance testing" for all EGUs, and proposed section 63.10005(a) and (b) require all affected EGUs to "demonstrate initial compliance . . . through performance testing . . . ." Furthermore, Commenter 17775 notes that Table 5 identifies emissions testing, CEMS, sorbent trap monitoring, and LEE testing as "performance stack testing." Commenter 17775 states proposed section 63.10005(a) defines "performance testing" to include the first 30-operating days of CEMS data. Commenter 17775 points out that although proposed section 63.10005(c) allows liquid oil-fired EGUs to "demonstrate initial compliance . . . by conducting fuel analysis," it is not clear whether the EPA intends that to constitute another form of "performance testing," or an exception to it, and if it is an exception to it, the other provisions do not reflect that. Accordingly, Commenter 17775 indicates the proposed rule on its face appears to require all EGUs to establish site-specific operating limits for all controls used to meet emissions limits under the rule, and maximum fuel pollutant limits for chlorine, Hg, and non-Hg metals "according to" the cited provisions and paragraphs regardless of the compliance "option" they choose.

Commenter 17775 states that the EPA must specify that the operating limits (including the operating load limit) and fuel input limits apply only to EGUs using stack tests to comply, or explain why those requirements are necessary for other units.

Commenter 17881 states that the EPA must revise the fuel types section in the proposed rule to clarify what requirements apply to each compliance option. According to the commenter, the EPA must provide a clear rationale for each proposed requirement.

Commenter 17775 assumes that the purpose of the control device operating limits is to help assure compliance between performance tests at EGUs that are not otherwise monitoring compliance with the relevant standard continuously (e.g., at EGUs not using CEMS or sorbent trap monitoring systems), and that the purpose of the fuel input limits are to ensure that EGUs that are not otherwise monitoring compliance with the relevant standard continuously (e.g., EGUs not using CEMS or sorbent trap monitoring systems) repeat the relevant performance test if their fuel characteristics change, such that compliance with the applicable limit at the current level of control is no longer assured. Commenter 17775 can think of no rationale for requiring sources that establish compliance with CEMS or sorbent trap systems to establish and demonstrate compliance with these other requirements. Commenter 17775 notes that this assumption appears to be supported, somewhat, by the EPA's few preamble statements. Commenter 17775 states the EPA must revise the rule and Tables significantly in order to make clear that only those EGUs that demonstrate compliance with a specific HAP or surrogate "through performance testing other than CEMS or sorbent trap monitoring systems," must comply with these requirements, or if the EPA does not so revise the rule, the EPA must issue a new proposal and provide a purpose for what appear to be redundant and unnecessary requirements.

Commenters 17775 and 17790 state that the proposed monitoring and compliance provisions are difficult to interpret and inadequately explained. According to the commenters, many of the EPA's proposed provisions simply require compliance "as applicable," but the EPA nowhere clearly states when the requirements apply. In other cases, the proposed applicability seems clear, but the reason is not. Commenter 17775 cites an example, that the EPA clearly states in the preamble and in the proposed rule that EGUs that choose to comply with a surrogate limit must test for the corresponding HAP as well, and that EGUs that choose to comply with a HAP limit must test for the corresponding surrogate. The commenter states that the EPA never explains why such testing is relevant, what the EGU is to do with the results, or how the proposed requirement can be reconciled with other provisions clearly allowing EGUs a choice between a HAP or a surrogate limit.

Commenter 17871 states that the compliance requirements are duplicative and burdensome and would not provide any additional protection to public health or the environment.

Commenter 17928 states that the EPA's proposed testing and compliance demonstration requirements are unnecessarily complex, confusing and burdensome.

Commenter 17795 requests that the EPA provide compliance demonstration flow charts for each of the categories of affected units. According to the commenter, when regulators conduct required permit inspections without meaningful flow charts and a clear understanding of multiple paths for compliance, there will be a tremendous amount of uncertainty for both the regulated community and the regulators. The commenter states that providing flow charts would make it easier to incorporate this type of information into existing Title V permits.

Response to Comment 16: The EPA has made changes in the final rule based on these comments to clarify and simplify the various monitoring and testing requirements. Please see the discussion in the final preamble. The EPA believes these clarifications eliminate unnecessary duplication and provide sources with clear options for demonstrating compliance.

Comment 17: Commenter 17820 recommends that the EPA provide clarification that units operating DSI technology will qualify for the option to use SO_2 as a surrogate for HCl. Commenter further states that the compliance demonstration, recordkeeping and reporting requirements need clarification and further explanation. The commenter states that the applicability of many requirements, like fuel input limits and control device operating parameters are unclear, and in other cases, the applicability seems clear, but the purpose is not or is questionable. According to the commenter, this can be addressed by providing additional clarity and explanation in the preamble to the rule or more specificity in the regulatory text concerning requirements for performance testing, continuous parameter monitoring systems, fuel sampling and analysis, control device operating parameters, monitoring and reporting.

Several commenters (17868, 18424, 18963) question the EPA's assumption that a large number of EGUs will use DSI to control acid gases. The commenter states that while DSI is a lower-cost option to reduce acid gas emissions, there is nothing in the history of its usage that suggests it is capable of achieving MACT acid gas emission limits in large EGUs burning medium to high sulfur coal. DSI is not in widespread use as a basic SO_2 control system, and commenter 18963 notes that there have been no commercially demonstrated applications of DSI for the control of HCl from coal refuse-fired CFB units. Commenter 17868 questions the EPA's assumption that the 3-year compliance schedule is achievable based on the use of DSI systems rather than FGD. Commenter 18424 also questions the EPA's projection that a large number of EGUs will use DSI to control acid gases, and the use of these controls will increase the use of high-sulfur coals. According to the commenter, the EPA's own consultant, Sargent and Lundy, has recommended not employing DSI on units burning coal with greater than 2.0 Ib/MMBtu sulfur content. The commenter states that more than 80 percent of coal mined in Indiana exceeds 2.0 lb S02/MMBtu, and it seems unlikely that utilities burning Indiana coal will utilize the lower cost DSI technology and will either install/upgrade scrubbers or retire coal-fired units where scrubbers are uneconomical. The commenter states that few utilities will install DSI when other regulatory requirements, such as the SO_2 emission reductions under CSAPR, are taken into account.

Response to Comment 17: A unit must use FGD in order to qualify for use of the SO_2 surrogate, for the same reasons as stated in the proposed rule. If a source uses DSI and FGD, then that unit would qualify. The Agency estimates an additional 329 EGUs will choose some form of acid gas control by 2015; should an owner or operator find DSI unsuitable, he or she could choose from other approaches, including FGD or FBC with reagent injection. With respect to the remaining general concerns about the clarity of the monitoring and testing provisions, please see response to Comment 16, directly above. Comments related to our assumptions with regard to DSI are responded to in the preamble to the final rule.

Comment 18: Commenter 17821 states that the EPA needs to revise the description and definitions of the IGCC APCD to account for upstream fuel cleanup and/or pollution prevention measures. The commenter states that for example, the technology used in IGCC units directly removes contaminants (such as particulate, Hg, non-Hg metal HAP, sulfur, chloride) directly from the fuel stream of IGCC units. According to the commenter, in this respect, IGCC is more akin to a natural gas-fired combined cycle unit, since it burns a syngas, which is cleaner than the coal combusted in a pulverized coal unit. According to the commenter, the EPA should reflect that IGCCs use upstream gasification/fuel clean-up (for example, AGR, SRU, PM scrubber) in the same way that coal-fired EGUs are credited for post-combustion or other air pollution control equipment such as SCR, ESP, and FGD. The commenter states that it makes no sense for IGCC to have additional testing burdens if reduced testing programs are allowed for coal-fired units with APCD. According to the commenter, the EPA recognizes that an IGCC unit is a distinct type of electric generating unit by proposing a separate subcategory for IGCC units, and the EPA needs to further acknowledge the process differences between IGCC units and PC units by providing clarification that for purposes of this MACT the affected facility is the combustion turbines and any emission limitations apply to the heat recovery steam generator HRSG stack. Commenter recommends that the EPA needs to provide further clarification that all upstream fuel clean-up in the IGCC process qualifies as control equipment, thereby not putting any additional testing burdens on IGCC units when reduced testing is allowed for coal-fired units with add-on pollution control equipment.

Commenter 19114 states that for IGCC units, the EPA should clarify the use of heat input and generation output terminology to account for (1) differences between coal-based (gasifier feedstock - based) and syngas-based heat input; and (2) differences between syngas-based and natural gas-based output during co-firing operations.

Response to Comment 18: The final rule does not establish different testing frequencies based on the presence of add-on controls, so the concerns raised by Commenter 17821 are no longer relevant. As the final rule contains definitions for *coal-fired electric utility steam generating unit, integrated gasification combined cycle electric utility steam generating unit, and natural gas-fired electric utility steam generating unit* in §63.10042, there is no need for additional clarification. According to the definitions. an IGCC that co-fires syngas derived from either coal or solid oil fuel with natural gas and get more than 10 percent of the average annual heat input during any of 3 consecutive calendar years or more than 15.0 percent of the annual heat input during any calendar year from syngas, it is an IGCC electric utility steam generating unit.

The commenters concerns about EPA not accounting for pre-combustions practices that remove HAP from the syngas are unfounded. Both the input and output based standards applicable to EGUs are production based limits. The EPA does not determine how a source will meet the standard only that the HAP emissions (or surrogate emissions) coming out of the stack must not exceed the standard. If a syngas production process removes sufficient HAP before combustion, the HAP concentration coming out of the stack should be compliant with the standards, perhaps even without the installation of add-on controls.

Comment 19: Commenter 17867 states that the EPA should revise and/or clarify some aspects of the rule.

a. Adjustments to the provisions concerning testing, initial and continuous compliance with the standards including:

i. The frequency of non-Hg metals and HCl testing should be extended if consecutive testing shows emissions meet the standard.

ii. If a source elects to use PM as a surrogate, the emission limit should be established during the performance test to ensure it correlates with either total or individual non-Hg metal HAP emissions.

iii. Filterable PM, as used by the EPA in the final Industrial Boiler MACT, is the appropriate standard to use as the non-Hg metals surrogate.

iv. The EPA should adopt work practice standards during periods of startup and shutdown for sources subject to the rule as used by the EPA in the final Industrial Boiler MACT.

v. The EPA should not require parametric monitoring for sources electing to show compliance by utilizing continuous emissions monitoring systems.

b. The EPA should allow states to request equivalency determinations based on state rules that cover the same pollutants, but with different control requirements and timing

Response to Comment 19: For the issue raised in item (a)(i), please see the discussion of the LEE provisions in the final preamble. For items (a)(ii) and (iii), the final rule establishes a filterable PM emission limit as a surrogate to the non-Hg HAP metals standards. This limit applies to all sources as an option, and is not established on a case-by-case basis. For the issue in item (a)(iv), the final rule requires the source to meet a work practice limit rather than a numerical emissions limit during startup and shutdown periods. See preamble for discussion. For the issue in item (a)(v), the final rule does not require parametric monitoring where a CEMS is used to demonstrate compliance. For item b, these standards apply as federally enforceable standards. A Part 70 operating permit may provide for certain streamlining of applicable requirements, consistent with the applicable guidance and requirements that govern the Part 70 program.

Comment 20: Commenter 17881 states that the requirements of section 63.10031 should not apply to start-up/shutdown and flame stabilization fuels.

Comment 21: Commenter 17928 requests the EPA to provide clarification on the compliance requirements for units that may change from being “natural gas-fired” to “oil-fired”. According to the commenter, the proposed rule is unclear with regard to how much time the EPA would allow a newly-designated oil unit to schedule and conduct initial performance tests to demonstrate compliance with the applicable standards.

Response to Comments 20 - 21: While the rule no longer requires compliance with emissions limits during periods of startup or shutdown, the rule maintains reporting requirements associated with the work practice requirements during those periods.

8. Cannot meet compliance deadline.

Comment 22: Commenter 18023 indicates that the requirement in section 63.10005(g) to demonstrate initial compliance for existing sources no later than 180 days after the compliance date is problematic for sources that may be in an outage or temporarily not operating on the compliance date. Commenter 18023 states the EPA should clarify that compliance demonstrations must be complete within 180 days after the compliance date or, if the unit is not operating on the compliance date, then 180 days after the unit begins operation. Commenter 18023 further states that given the concerns that the proposed rule provides inadequate time to install controls, it is likely a number of utility units will be shut down on the compliance date.

Commenter 17714 states that the 3-year compliance deadline could be problematic because utilities must also consider the potential impact of the GHG NSR permitting requirements that could be triggered for large emission control projects, especially wet flue gas desulfurization projects. The commenter states that the “Tailoring Rule” provisions can be triggered by some projects because of the required timing of emission control projects necessary to meet the emission limits of the proposed rule, thus initiating the GHG BACT analyses requirements during the permitting process. The commenter states that GHG BACT is a largely unchartered area for both the regulated community and the state regulatory agencies and will likely create additional permitting delays. According to the commenter, these delays will be exacerbated by challenges to the permits by those seeking to minimize GHG emissions. Commenter recommends the EPA include an exclusion from the requirements to obtain construction permits, including greenhouse gases under the Tailoring Rule, for emissions controls needed for an existing unit to meet the emission limits of the Utility HAP MACT Rule.

Commenter 17736 states that a 3-year compliance requirement is not feasible. Commenter disagrees that the data proposed in the regulation is complete and it relied on faulty assumptions and unproven technologies. According to the commenter, compliance and implementation requirements under the proposed Utility MACT Rule are unreasonable and overly burdensome for the regulated community.

Response to Comment 22: The rule maintains the requirement for existing EGUs to demonstrate initial compliance within 180 days after the compliance date of the rule. Source owners or operators have the ability to schedule equipment installation, if needed, as well as EGU operation so that the requisite emissions demonstration can be completed on time. Should an owner or operator find that despite his or her best effort to meet the compliance date additional time is required to install controls, he or she can request up to a 1-year extension from the Administrator.

Some commenters thought that EPA permitting could cause delays in implementing this rule. The EPA recognizes that, following the vacatur of the new source review (NSR) pollution control project exemption in *New York v. EPA, 413 F.3d 3, 40–41 (D.C. Cir. 2005),* pollution control projects, including pollution control projects constructed to comply with this rule, have the potential to trigger NSR permitting. Based on an analysis done in 2005 that looked at SCR and FGD for CAIR compliance, but that remains current and relevant for all pollutants except for GHG, EPA believes that NSR requirements would not significantly impact the construction of pollution controls that are installed to comply with this rule. In addition, it is very unlikely that pollution control projects would cause GHG increases that would exceed the 75,000 tons per year threshold either as a result of either chemically manufacturing GHGs or as a result of parasitic load. The EPA concludes therefore that there will be no significant impacts on timing from NSR for any pollution control projects resulting from this rule. Should NSR be triggered it would at most be for just a few of the projected control installations. In the limited circumstances where pollution control installations under the Mercury and Air Toxics Standards may trigger NSR, we also note that an expedited permitting process can occur with sufficient time to obtain permits and achieve emission reductions. For this reason, we strongly encourage permitting authorities to expedite permitting for any such projects, which are likely to be very limited in number.

Some companies may construct replacement generation as a compliance strategy. State pre-construction permitting requirements depend upon each individual state. Some states do not require pre-construction permits while some others require public utility commission (PUC) approval. For states obtaining PUC pre-approval for cost recovery, authorization typically averages seven months and is obtained usually within one year.[19] Furthermore, while PUC approval is necessary to recover investment costs through rate payers, it is not a prerequisite for obtaining credit or performing conceptual studies.

Comment 23: Commenters 17689 and 17790 state that the DSI technology can achieve the levels of reduction necessary on EGUs using high chlorine eastern bituminous coals to meet the proposed MACT HCl limits. According to the commenters, the alternative control option of FGD cannot be timely installed to meet the proposed compliance deadline as the EPA admits.

Commenters 17689 and 17886 state that the EPA's determination that over 56 GW of needed DSI technology can be installed in time to meet the compliance deadline raised issues related to whether the installation of dry scrubbers could be accomplished in time and whether the additional demands for the dry sorbent would be available in time.

[19] "Public Utility Commission Report" March 31, 2011 by M.J. Bradley & Assoc LLC; web site: http://www.epa.gov/ttn/atw/utility/puc_study_march2011.pdf

Commenter 17790 disagrees with the EPA's assumption that DSI with fabric filters will provide compliance-level reductions to meet the very stringent acid gas limits at all units. Without data that demonstrates otherwise, Commenter 17790 expects compliance with this proposed rule will require FGD on over 60 percent of coal-fired EGUs.

Commenter 17765 states that the DSI technology has not been widely used or tested to date and there is little or no satisfactory evidence which demonstrates that an actual unit can comply with all of the proposed NESHAP using DSI without a scrubber.

Commenters 17765 and 17820 believe that without further testing to confirm that DSI technology will work without a scrubber, it is highly unlikely any utility's compliance strategy will rely only on DSI technology. The lack of experience with the DSI technology also highlights the problem with setting emissions standards pollutant-by-pollutant, as there is also insufficient data to confirm whether a unit using DSI with or without a scrubber can meet all three standards on a continuous basis without creating antagonistic impacts to the overall effectiveness of other control technologies.

Commenter 17820 states that to satisfy the HCl emission limit of 0.002 lb/MMBtu as proposed in the rule, DSI may be a viable option at a reasonable cost for coal with chlorine < 300 ppm. The commenter states that for coal with chlorine between 300 to 1000 ppm, DSI could still be used but variable operating costs will increase substantially, while for coal with chlorine greater than 1500 ppm, removal requirements will be difficult and variable operating costs could approach $8-$10/MWh or higher. According to the commenter, some companies that burn certain eastern bituminous coals may not be able to achieve compliance with the acid gas standards using DSI, because the higher chlorine content found in these coals necessitates a more aggressive control technology to remove higher levels of HCl. According to the commenter, to comply, these companies may have to install wet FGD, which presents major challenges to the 3-year compliance deadline that the EPA optimistically asserts companies will be able to meet.

Commenter 17820 states that the EPA assumes that an adequate supply of dry sorbents is readily available in the RIA, yet sorbent production would need to increase by 10 to 20 times in order to meet the EPA's projected DSI demand. The commenter states that it is uncertain whether suppliers will be willing to increase production without concrete assurances of future demand through mechanisms like take-or-pay contracts; uncertainties about the future power market and potential problems from DSI use will make companies' decisions about employing DSI complex and lengthy, and some may be reluctant to take on large take-or-pay obligations. The commenter states that even assuming suppliers are willing to commit hundreds of millions for plant expansions that may be needed to increase supply, it will still take more than 18 months to ramp up dry sorbent production. The commenter states that there are also substantial questions about the Trona supply chain. According to the commenter, the sole regional supply of Trona from the Green River, Wyoming area takes two to four weeks to deliver, Trona is shipped by rail in sealed pressure discharge ("PD") railcars that typically hold a little less than 100 tons of product, and Trona properties and feed issues limit the size of a plant's storage silo to 200 to 300 tons. The commenter asserts that given the space constraints at many facilities, a large quantity of Trona will need to be stored in rail yards on the PD railcars, and it is unclear whether there are enough PD railcars to accommodate such an expanded use of DSI. The commenter states that if rail service is unavailable to a given power plant, then trucking the material to the site may cause additional logistic problems because of the large number of truck trips needed at substantially increased cost. The commenter also states that material suppliers recommend that Trona not be stored for more than one month because longer storage times may diminish the material's effectiveness and negatively affect the product's flow ability. According to the commenter, this storage restriction will have repercussions throughout the supply chain. The commenter states that the RIA is overly optimistic about the use of DSI and, in turn, understates the cost of complying with the proposed MACT limits (because more units will need to install either a more expensive wet or dry scrubber). According to the commenter, consequently, the time estimated to comply with the proposed rule is also understated.

Commenter 17821 states that a number of technical issues must be adequately answered before utilities can proceed with widespread adoption of DSI technology. According to the commenter, the use of DSI has substantial crippling impacts on other pollution control systems currently in use at utilities.

a. According to the commenter, increased mass loading combined with increased ash resistivity can increase PM emissions. The commenter states that calcium-based sorbents have higher inherent resistivity, making it very difficult to collect in an ESP and resulting in deteriorated performance. The commenter also states that sodium-based sorbents shave acceptable ash resistivity for applications in ESPs, but under certain conditions sodium bisulfate is formed. According to the commenter, sodium bisulfate has a sticky phase at temperatures above 330 ºF-350 ºF, and this sticky phase has caused significant operational problems in a number of units, causing plug gage of systems and components in the gas stream. According to the commenter, under certain conditions, sodium-based sorbents can serve as a catalyst to convert NO to NO_2. This can cause an orange brown color in the stack plume

b. The commenter states that regarding fabric filters and DSI, there is not a sufficient number of medium-to-high sulfur coal burning units that are equipped with fabric filters to determine whether they can operate reliably without experiencing degraded bag life from acid attack or H_2SO_4 dew point corrosion, plug gage and/or blinding. DSI for fabric filter protection is not an industry standard. According to the commenter, there are operational and reliability risks in installing fabric filters on large EGUs burning medium to high sulfur coals. The commenter states that the negative effect of SO_3 from high sulfur coals on ACI for Hg control is well documented in DOE studies. According to the commenter, installing a fabric filter on a large EGU burning medium to high sulfur coals is not a simple “off the shelf” solution for Hg control;a fabric filter with DSI may hinder a unit’s ability to meet the proposed MACT limits for Hg and PM. The commenter states that in one test where both DSI and ACI were injected upstream of a polishing fabric filter, the addition of DSI caused the unit to need three times the normal amount of ACI to achieve the same level of Hg control. The commenter also states that in addition, for a large majority of DSI cases, retrofitting a fabric filter would be required, an installation that will take at least 30-35 months in general to complete; this is after the facility has the necessary approvals such as an air permit, specifications completed, and a contractor secured before it can actually commence construction. According to the commenter, these steps could easily add several additional months; total project length including these other factors could easily be 42 months. The commenter states that in its proposed rule, the EPA has underestimated or not considered these additional burdens of installing fabric filters, activated carbon, and sorbent injection.

c. According to the commenter, companies may need to install other technologies such as wet FGD, which has an expected implementation time of 52 months after necessary permits and other approvals are secured. The commenter states that this point is critical given that the EPA finalized CSAPR in July, 2011, with a compliance date of January 1, 2012, a quick turnaround that will force some companies to commit to FGD installation to meet SO2 requirements. According to the commenter, even if a company were to decide on August 1, 2011 to install an FGD, which is four months before the Utility MACT is scheduled to be finalized, there is still not enough time to permit and install an FGD three years after a final MACT rule.

d. Commenters 17821 and 17840 state that with injection rates of Trona at approximately 600 lb/hr, engineering studies have shown HCl removals at less than 20% with virtually no HF removal across a fabric filter. According to the commenters, the EPA needs to qualify the assumptions on how much DSI is required for acid gas removal to meet the emission limits required in this rule. The commenters state that there are not enough engineering data that both demonstrate compliance level removal rates and document accompanying balance of plant effects; for example, larger alkali injection rates can cause pH upsets in downstream systems and environmental controls. According to the commenters, the injection of Trona in an EGU generates NO2 which degrades activated carbon.

Commenter 17881 states that additional time is needed to thoroughly evaluate the feasibility of DSI, as such, considerable additional investigation on the widespread application of this technology is warranted. According to the commenter, the use of DSI will likely require a fabric filter to avoid NSR and PSD permits. The commenter states that while DSI may be installed in less than three years, engineering, permitting and constructing a fabric filter will, in fact, take longer, and that this concept is further complicated by any need to replace existing ash handling systems in order to accommodate the higher volume of wastes (i.e., fly ash and spent/unspent reagent) associated with DSI.

Several commenters (17756, 17758, 17790) are concerned that the EPA overestimated the number of DSI devices that will be used. Commenters 17758 and 17790 note that units burning eastern bituminous coals may not meet the acid gas standard using DSI; therefore they may use FGD instead.

Commenter 18037 states that the presumption that sorbent injection or dry scrubbing will be installed over wet scrubbing systems implies that the EPA is looking solely at this proposed rule and not the suite of rules the electric generating industry will be facing. According to the commenter, when considering all the rules, wet scrubbers may be the control of choice over dry systems and the installation time for wet scrubbers is significantly longer.

Response to Comment 23: As mentioned in the response to comment 17, the agency finds that a number of additional EGUs will choose some form of acid gas control by 2015; should an owner or operator find a particular approach such as DSI unsuitable, he or she could choose from other approaches, including flue gas desulfurization or fluidized bed combustion with reagent injection. Source owners or operators have the ability to schedule equipment installation, if needed, as well as EGU operation so that the requisite emissions demonstration can be completed on time. Should an owner or operator find that despite his or her best effort to meet the compliance date additional time is necessary for the installation of controls, he or she can request up to a 1-year extension from the Administrator.

9. Request to modify compliance requirements.

Comment 24: Commenter 17800 requests the EPA to exempt EGUs from the annual tuning requirement in section 63.10021(a)(16)(iii) and (iv) if such units use a continuous tuning algorithm to optimize the air-to-fuel ratio, and minimize NO_X and CO production. The commenter states that in section 63.10021(a)(16)(iii) and (iv) the EPA is requiring the annual inspection of systems controlling the air-to-fuel ratio and optimizations of CO and NO_X consistent with manufacturer's specifications. According to the commenter, while the EPA references air-to-fuel ratio, typically boiler operators use excess O_2 to determine proper combustion; the general indicator of incomplete combustion is high CO levels or unburned carbon in the fly ash, and operators use O_2 set points to insure combustion has been optimized. Currently Commenter uses a neural network computer system to optimize the boiler combustion and minimize NO_X and CO production; this system continually tunes the boiler combustion process based on boiler operating parameters. According to the commenter, an annual optimization is unnecessary, as this is being done continuously.

Response to Comment 24: The EPA has decided not to include alternate work practice standards, such as a CO requirement, but has adjusted the language in the final rule to recognize the value of automated boiler optimization tools such as neural-net systems. The EPA has reviewed the comments on the proposed frequency of tune-ups, and made adjustments in the final rule. See further detail in the response below on the timing of tune-ups required under the final rule.

Comment 25: Commenters 17800 and 17881 state that in section 63.10021(a)(16)(ii) the EPA is requiring flame pattern inspections and that to make this happen, the EGUs need to install observation ports. Commenters request the EPA to exempt them from this requirement as inspecting the flame would not provide useful information relative to optimizing CO and would be extremely expensive, as tubing in the boiler would have to be reconfigured to accommodate the port. According to the commenters, in some wall-fired coal boilers, there are observation ports which can be used to determine if flames are impinging on the furnace walls. The commenters state that while a qualitative evaluation can be made regarding the general appearance of the flames (bright, dark, etc.), observation of the flames is rarely, if ever, used to access the impact on NOx or CO; for instance, flame observation on cyclone and coal-fired tangential boilers would not generally be useful. According to the commenters, the cyclone itself is the burner and the flame is opaque;, in general, the furnace of a tangential boiler is essentially the burner as well, and in the case of a coal-fired tangential boiler, the furnace is filled with a spiraling flame that covers most of the furnace. The commenters state that the EPA has apparently recognized this by requiring that the flame pattern must be inspected "*as applicable*." Nevertheless, Commenters request exemption for those boilers that do not currently have observation ports or it can be shown that observation of the flames in these boilers provides no useful information relative to minimizing CO.

Response to Comment 25: The EPA has modified the rule to state that if specific aspects of the inspection process are not applicable to a given boiler type, then those elements of the basic procedure would be adjusted according to best combustion engineering practice for that burner type.

Comment 26: Commenter 17818 states that for compliance, it appears that the alternate limit in this case (of alternate Hg limits) would require both a simultaneous significant emissions reduction to the levels of the primary limits and a significant reduction in unit heat rate [when an Hg emission rate limit of 1.0 lb/TBtu or 0.008 lb/GWh and the apparent correction factor (unit heat rate) of 8000 BTU/KWh is applied]. According to the commenter, this scenario seems unlikely for most owners and operators.

Response to Comment 26: Conversion errors made in the proposed limits were brought to our attention and corrected. We believe that the final limits do not contain the issues noted by commenter.

Comment 27: Commenter 17821 states that existing IGCC units should be able to use SO_2 as a surrogate for acid gases (e.g., HCl) as an alternative to measuring HCl since SO_2 emissions are controlled upstream via acid gas scrubbing to reduce sulfur. Commenter collected SO_2 data during the ICR test at Wabash River IGCC and provided that data to the EPA as requested. Commenter has submitted to the EPA well over a decade of SO_2 data under the Acid Rain Program. According to the commenter, at a minimum, the EPA could set an SO_2 surrogate limit to be the same value as other coal-fired units, or the EPA could use data from the two existing IGCC sites. The commenter states that the EPA should not limit having SO_2 as a surrogate just to units with a FGD system when other proven and effective SO_2 emissions reduction technology exists and states that as an example, General Electric's gasification technology, currently being installed at the Edwards port IGCC, uses water scrubbing of syngas at high temperatures which removes water soluble acid gas compounds such as HCl, HCN, HF, and Cl_2. The commenter states that the emission controls for the Wabash River and Polk Station IGCC units have their own variations, which are distinctively different from conventional coal-fired units. Commenter proposes that new and existing IGCC units should have the opportunity to use SO_2 as a surrogate measurement of acid gases.

Response to Comment 27: The EPA has acknowledged that IGCC EGUs qualify for the alternate SO_2 compliance alternative in the final rule and has based such limits on the two operating IGCCs.

Comment 28: Commenter 17881 states that to measure the mass flow of air and fuel to maintain a desired 'ratio' does not work. The commenter states that facilities will periodically calibrate flow transmitters on the air measurement system and coal feeders on some plants, and boiler firing controls are based on maintaining boiler drum pressure and trim air in order to maintain a desired excess O_2 leaving the boiler; enough coal is put in to combust and maintain pressure, and enough air is put in until a desired excess oxygen is achieved leaving the boiler. The commenter states that coal properties vary greatly (heating content and moisture), so coal feed rates at a desired load can vary greatly, and consequently, the mass of air entering the boiler varies greatly.

Response to Comment 28: The EPA recognizes the inherent difficulties of combustion optimization and has modified the rule language to allow more flexibility in conducting tune-ups and maintaining combustion controls, including incentivizing the use of neural net combustion optimization systems.

Comment 29: Commenter 17902 states that each power plant is anticipated to require at least one additional full-time person to perform necessary MRR compliance demonstration tasks that are required on a daily, weekly, monthly, quarterly and semi-annual basis. According to the commenter, this does not include the external resources and costs associated with stack testing or fuel analyses. The commenter states that these MRR requirements are duplicative and excessive and would provide no further assurance of compliance with the emission limits in the Utility MACT Standard.

Response to Comment 29: The EPA has decreased the frequency of required testing and work practices to levels that are expected to significantly reduce the issues raised by the commenter.

Comment 30: Commenter 17914 states that while many of the proposed provisions of the rule are technically achievable, there are some limits which are not sustainable in day-in/day-out operation at EGUs which face a complex mix of fuel variability, combustion management, turbine integration and Air Quality Control Systems(AQCS) performance optimization challenges and constraints. Commenter requests that the EPA reconsider several aspects of the rule, which as proposed would severely hinder reliable, long-term operation of these key assets in our nation's energy infrastructure and seriously jeopardize the addition of new, more efficient fossil fuel EGUs.

Response to Comment 30: The EPA believes that variability has adequately been addressed in setting the MACT limits in the final rule as explained in response to other comments in the final rule record.

Comment 31: Commenter 17930 states that the EPA has provided no evidence that the amounts of ACI reductions that have been achieved are not the maximum capabilities that can be achieved at those units. According to the commenter, the ACI technology cannot deliver results that even approach the degree of control or consistency that the EPA claims. Using the same ACI control technology to the fullest extent, and operated in the same manner, over multiple units, Commenter has experienced mercury emissions reductions ranging from 30 percent to 80 percent - far below the EPA's predicted reductions of over 90 percent and nowhere close to the consistency that would justify setting a limit such as that proposed by the EPA.

Commenter 18498 disagrees with the EPA proposal not to use technologies other than ACI as the basis for a beyond-the-floor analysis related to Hg emissions. The commenter states that Mercury Oxidation System Technology and addition of calcium bromide during the combustion process are control options that are being examined by Commenter and others. According to the commenter, given the stringency of the proposed standards and emerging technologies, the EPA should not limit the proposal to ACI and DSI. Commenter recommends that the EPA consider additional options that would allow for compliance while protecting grid reliability and reducing retrofit costs passed to consumers; for example, a viable option would allow a facility to operate at a reduced capacity factor rather than being required to retire or achieve the standards in the proposed rule. The commenter states that allowing a facility to adopt a capacity factor of 10 percent or less would achieve the desired result of reducing emissions but would not place the EPA in the position of dictating energy generation profiles and that such an option would help ensure reserve capacity for the grid and at the same time reduce emissions. According to the commenter, the EPA has set a standard that will be difficult for sources to comply with using technology the EPA has recommended in the proposed rule. For example, states the commenter, using DSI technology to meet the acid gas HAP emission limits actually makes it more difficult to comply with the PM emission limits because the dry sorbent injected into the flue gas stream reacts with SO_2, creating sodium sulfate, a particulate that must be captured by the PM control device in addition to the other particulates in the flue gas stream. Commenter suggests that the EPA revise its proposal and set a new MACT floor based on the best performing 12 percent of units overall, rather than the best performing 12 percent of units for each pollutant. According to the commenter, using a methodology that considers emissions limitations for all regulated pollutants actually achieved in practice by the best performing 12 percent of sources will result in a MACT standard that complies with section 112(d)(3)(A), and abandoning the pollutant-by-pollutant approach will take into account the interactions between pollution control devices. The commenter states that although DSI has produced some short term promising results, there are no long term units operational for prediction of potential unintended environmental concerns, but it is known that sodium bicarbonate from the DSI process is a base that will be disposed with coal ash, in many instances in ponds. The commenter states that where a base is added to the pond, the water will necessarily have to be treated with an acid to decrease the pH in the pond; at this time, there is insufficient information to know either the amount of treatment that will have to occur or the ramifications to existing ponds, and thus, at this time there is insufficient information to assess whether DSI will be an appropriate long term solution.

Response to Comment 31: The EPA believes that the results from ICR testing for units in the low Btu, virgin coal subcategory that were also using ACI, in combination with the publically available information from the DOE/NETL mercury control demonstration program, supports that consistent mercury removal levels > 90% are achievable when the correct sorbent is properly used (i.e., injected corrected and at the correct rate). The EPA understands and acknowledges that control technologies other than ACI are also available that can achieve deep reductions in mercury control. This rule does not mandate the use of any particular control technology (such as ACI). The comments on the pollutant-by-pollutant approach have been addressed elsewhere in the response to comments document.

Comment 32: Commenter 17702 states that the EPA's proposed compliance requirements are overly burdensome and should be modified. According to the commenter, some of the compliance requirements may result in periods of noncompliance by EGUs that may be capable of complying with the emission limits under normal operations.

Response to Comment 32: The final rule makes a number of changes to streamline the compliance requirements. Please see the final preamble for further discussion.

10. Need clarification on output-based limitations.

Comment 33: Commenter 17385 states that Tables 1 and 2 of the NESHAP list output-based limitations in units of mass of pollutant per electrical output (lb per MWh, lb per GWh). The commenter states that there is no legend to clarify net or gross bases or if only electrical output is included but that in the Federal Register preamble discussion of the NESHAP limitations, Table 10 (76 FR 25027) does include a legend that clarifies units and their bases.

Response to Comment 33: The rule requires electrical output based on gross generation; all Tables have been updated to specify gross generation.

11. Improve sustainable efficiency.

Comment 34: Commenter 17620 states that the EPA should develop a record in the upcoming EGU GHG regulations that would enable accurate measurement and determination of sustainable efficiency improvements. According to the commenter, the record in this rulemaking is not sufficient to establish such procedures.

Response to Comment 34: Any GHG related comments are outside the scope of this rulemaking.

12. Support work practice standards.

Comment 35: Commenter 17790 supports the use of work practices standards included in the proposed EGU MACT to ensure compliance with the proposed organic HAP. Commenter also agrees that emissions from coal-fired boilers will likely be less than detection limits for most organic HAP, and further comments that this testing can be expensive and because of the low levels, results can be unreliable. According to the commenter, proper combustion will ensure low emissions of organic HAP and requiring proper combustion is the best means of control.

Response to Comment 35: The EPA acknowledges the support and has retained in the final rule a work practice standard for organic HAP emissions.

13. Request to modify or remove work practice standards.

Comment 36: Commenters 17638 and 17818 request that the EPA establish a work practice standard in lieu of emission limits for organics and dioxin/furans. Commenters disagree with some of the individual elements of the work practice standard, such as the 18-month work practice interval and the requirement to inspect flame patterns as a means of determining optimized combustion. Commenter 17818 further states that conducting burner inspections will often include a requirement to install scaffolding in the furnace, to gain access to the burners, and then removal of the scaffolding. According to the commenter, this is a process that is both expensive and time consuming, as well as generally not required except to perform burner inspections or perform repairs, and such activities are generally not done on an annual basis, but rather are less frequently performed during periods of extended maintenance shutdown/inspection. Commenters proposed that the 18-month maximum outage interval should be extended to 24-30 months and the inspection of flame patterns for EGUs for the purpose of tuning burners is improper. EGUs can have 50 or more types of burners, and not all flames are visible.

Inspecting flame patterns is more useful for industrial boiler practices in which an observer peers through a glass at the burner and then makes changes to nearby controls to optimize the flame. Commenter 17638 supports a CAM-type approach regarding the establishment of work practices, which provide for reasonable assurance of the unit operation in lieu of a “one size fits all” approach.

Several commenters (17689, 17756, 17928, 17813) state that the 18-month interval between inspections is not consistent with established utility practice regarding periodic outages for maintenance and repair. Commenters recommend a 36 month compliance period. According to the commenters, utilities should be able to implement their own best management practices if they are demonstrated to be best for the unit. For small systems, such as many rural electric cooperatives, state the commenters, many parts may not be inventoried and may take several months to acquire, and to complicate matters, units may be in periods of high need, such as during summer or winter peaking when replacement parts become unavailable, thus making shutdown for repair not feasible due to reliability or other paramount concerns. In such cases, commenter 17689 believes utilities should be given reasonable time to optimize considering the electric demands on the system.

Commenter 17756 states that the work practice standards for EGUs to address any emissions of organic HAP and dioxins do not reflect some of the practical realities of operating an EGU.

Several commenters (17761, 17767, 17795) state that the proposed work practice standards regarding organic HAP will have a detrimental impact on the outage schedules of applicable units since every unit would have to perform an onerous inspection and tune-up every 18 months. According to the commenters, this scheduled tune-up would require additional outages in between planned major maintenance overhauls further affecting unit availability, overall system reliability, and generating costs. The commenters state that the EPA’s ICR test data demonstrated that the majority of applicable units emitted non-detectable levels of organic HAP, even under the utility industry’s existing work practice standards and maintenance outage cycles. Commenters 17761 and 17795 suggest that there is no need for increased scheduled outages and inspections (every 18 months) for units already emitting non-detectable levels of these HAP and, as such, these standards should be removed from the final rule. Commenter 17767 recommends an extension beyond 18 months.

Commenter 17851 states that the EPA should not set a dioxin/furan standard or a non-dioxin organic HAP standard. Doing so will not reduce the emissions of organic HAP.

Commenter 17851 states that the EPA should not set a dioxin/furan standard or a non-dioxin organic HAP standard and that doing so will not reduce the emissions of organic HAP.

Commenter 17930 states that the EPA should allow utilities to document their own operating practices, including testing, data collection, and inspection schedules. According to the commenter, each utility has developed documentation practices that best, and most efficiently, serve that particular plant and company and to require other documentation practices would be an unnecessary burden on already taxed utility operators. The commenter states that there are many instances where emissions are below detection levels and should not be used as a basis to establish a work-practice standard.

Several commenters (19536, 19537, 19538) states that the work practice standard should require that all EGUs install real-time software to continuously optimize boiler combustion and perform soot cleaning. According to the commenter, these systems continuously monitor the combustion process to determine the optimal balance of fuel and air flows in the furnace to position dampers, burner tilts, overfire air and other controllable parameters at their optimal setting. The commenter states that these systems are already in widespread use throughout the utility industry and have the added benefit of improving efficiency, thus reducing operating costs. According to the commenter, a boiler tune-up is not adequate to assure continuous minimization of organic HAP. The commenter asserts that the work practice standard assumes that all organic HAP are created by incomplete combustion and that this assumption is incorrect, especially for dioxins which are formed after the combustion process and whose emission rate depends in part of coal chlorine content.

Response to Comment 36: The EPA has reviewed the comments on the proposed frequency of tune-ups, and made adjustments in the final rule. Under the final rule, the tune-up must be conducted at each planned major outage and in no event less frequently than every 36 months, with an exception that if the unit employs a neural-network system for combustion optimization during hours of normal unit operation, the required frequency is a minimum of once every 4 years (48 months). The EPA believes the minimal recordkeeping associated with this work practice standard is not unduly burdensome. The EPA does believe that a work practice standard is the best approach for controlling organic HAP, and thus has retained the work practice standard in the final rule.

14. Delegation to states (compliance dates).

a. General support.

Comment 37: Commenters 17758 and 17909 indicate that allowing states to seek delegation of the section 112 program will provide important compliance flexibility (particularly related to timing of retirements, repowerings, and installations of control equipment) for those units and utilities that have already made investments consistent with state environmental programs, and failure to allow state delegations could undermine these investments. Commenter 17758 further indicates that if states can demonstrate that overall emissions reductions are equivalent or greater than those that would be achieved by the proposed rule, the EPA should delegate the section 112 program to these states, even if the state emissions reductions would not necessarily occur on the same schedule.

Commenter 17798 states that the EPA needs to be aware that states with existing Hg rules may request approval of their rules in meeting the EGU NESHAP. According to the commenter, to this point, Wisconsin, under state statute, is required to establish state rules for implementing any federal NESHAP requirement. Commenter requests the EPA to include a process in the NESHAP rule which will facilitate states in establishing rules as equivalent to the EGU NESHAP. For Hg emissions and other accumulative impact pollutants, the commenter suggests equivalency can be measured by comparing total emissions on a statewide or corporate utility basis.

Commenter 17719 is concerned about existing sources subject to state-only rules for the reduction of Hg and other air toxic emissions. Commenter does not want the promulgation of the MATS to undermine the tremendous amount of work invested in creating a program to curb emissions within a reasonable timeframe, protecting both the economic viability of the state and the health of the public. Commenter seeks to make use of temporal flexibility, authorized under CAA section 112(i)(3) in obtaining delegation of the MATS to preserve a hard negotiated comprehensive Colorado-specific program designed to yield greater emission reductions than the MATS alone. The commenter states that the state has taken three separate actions to reduce the emissions of criteria pollutants and HAP from coal-fired utility boilers.

a. The Colorado Air Quality Control Commission (AQCC) adopted state-only Standards of Performance for Coal-Fired Electric Steam Generating Units into Regulation No. 6, Part B, Section VIII on October 18, 2007;

b. The Colorado Legislature passed House Bill 10-1365, the "Clean Air-Clean Jobs Act" ("CACJA"), on April 19, 2010; and

c. The AQCC adopted revisions to the Regional Haze State Implementation Plan ("RH SIP") in Regulation No. 3, Part F on January 7, 2011.

According to the commenter, under these rules, the state has successfully negotiated both emissions standards and shut down provisions with Colorado utilities to reduce the emission of criteria and hazardous air pollutants on a timetable that protects the public interest. The commenter states that the CACJA in particular resulted in extensive negotiations to ensure the reliability of the energy grid while encouraging the use of renewable and cleaner energy sources, taking into consideration cost impact to customers, necessary transmission system changes, unit outage schedules and outage contingencies, and construction timeframes, and that ultimately, the CACJA will promote job growth and reduce air emissions within the State.

Commenter 18034 states that the state agencies that receive delegated authority for the final NESHAP rule will be tasked with enforcing the rule. According to the commenter, some of the issues will directly impact its ability to appropriately enforce the rule, and the EPA must consider how state agencies will be expected to enforce the rule.

Comment 38: Several Commenters (17758, 17873, 17756) state that the EPA should allow states to seek delegation of the CAA section 112 program, as authorized by the Act. Section 112(l) of the CAA allows a state to seek delegation of the section 112 program. The commenters note that in the proposed rule the EPA acknowledges that a number of state and local program have plans to address environmental issues and that these plans may lead to reductions in HAP emissions equivalent to or greater than the proposed rule.

b. Support for specific state/local or EGU.

Comment 39: Commenter 18019 states that they encourage the EPA in the final MACT rule to make clear that Oregon has regulatory flexibility to address the unique Boardman case. In particular, the commenter asks the EPA to expressly recognize that Oregon could obtain delegated authority under section 112(1) to implement the MACT consistent with the Boardman 2020 plan, where the plant will achieve mercury reductions both ahead of and in excess of any federal standard, meet the acid gas and organics standards in advance of the MACT requirements, and cease coal burning entirely by 2020. Commenter urges the EPA to expand on this concept in the final rule and make clear that plans, such as the Boardman 2020 plan, coupled with the early mercury reductions, would meet the "no less stringent" test for state delegated programs.

Comment 40: Commenter 17867 states that early termination of coal operations and interim controls will result in lower aggregate emissions of haze causing pollutants than those projected under a much more expensive control package that would have otherwise been required to run the plant indefinitely in compliance with haze-related standards. According to the commenter, the EPA's proposed Utility NESHAP Rule is one of several the EPA rules that will affect the nation's coal fleet, including the Boardman facility. The commenter states that the Boardman plan requires Commenter to install pollution controls to reduce interim emissions of NO_X by about 50 percent through the installation of advanced combustion controls, and to reduce SO_2 emissions through a combination of lower-sulfur fuel and the installation of a DSI system. According to the commenter, under the Boardman 2020 plan, all emissions associated with coal-firing at the Boardman Plant will end by 2020, resulting in dramatic reductions in all conventional pollutants (SO_2, NO_X, PM), Hg, other HAP, and GHGs. In addition, the Boardman 2020 Plan establishes a path toward significant reductions in CO_2 emissions in advance of regulation by mapping a careful and reasonable transition away from coal-fired generation at this facility. According to the commenter, the EPA regulations would require pollution upgrades in order to meet air quality, water quality or waste management requirements, and once these regulations are finalized, a key question facing electric utility companies is whether to retrofit and run coal units into the future or to retire these units. The commenter states that these decisions are challenging given continued uncertainty about federal climate policy and that the EPA could resolve this dilemma by establishing a clear regulatory pathway that allows the state to preserve a Boardman-like plan and reconcile it with the requirements of CAA section 112. Commenter recommends that the EPA consider providing commenter and ODEQ specific guidance for a state plan containing the following elements, that if offered by the ODEQ in connection with other elements needed for compliance assurance, would be considered by the EPA as potentially meeting the equivalency requirements of section 112 and subpart E:

a. A Hg standard more stringent and imposed earlier than the federal rule. The commenter states that the Oregon Utility Mercury rule was promulgated in 2006 and requires Boardman to meet an aggressive standard of removal of at least 90 percent of the Hg emitted from the unit or a limit of Hg emissions to 0.60 pounds per trillion BTU of heat input by no later than July of 2012; thus, Boardman would achieve Hg controls that are well below the EGU MACT proposed limits and have them installed at least 3 years early.

b. An acid gas standard the same as, or more stringent than, the proposed federal rule. The commenter states that to meet BART requirements for SO_2, PGE is installing a control package that includes DSI technology, and anticipates the use of low sulfur coal; while installation has not been completed, and full scale testing to determine control effectiveness has not been done, based on preliminary evaluations, commenter believes that the DSI technology is likely to have the collateral effect of removing acid gasses to achieve compliance with the standard.

c. The proposed section 112 work practices standard for dioxin/furans and for the non-dioxin/furan organic HAP. The commenter states that these are already contemplated under existing requirements for the Boardman Plant.

d. A slightly less aggressive limit for non-Hg metals. The commenter states that this might be either the existing PM emission limit of 0.04 lb/MMBtu (filterable) as a surrogate for non-Hg metals or slightly relaxed individual or total metals limits. According to the commenter, while Oregon potentially could allow marginally higher emissions than the federal standard, the Oregon plan would require complete phase out of fossil fuels by 2020, which would result in significantly lower aggregate non-Hg metal emissions compared to continued operation in compliance with the MACT standard under the EGU NESHAP proposal.

e. A requirement that coal firing at Boardman be stopped by 2020, which would result in of the dramatic reduction in all HAP and other pollutants. Commenter believes such a set of requirements, which would contain some elements that are more stringent than the federal rule and others that are slightly less stringent, would – taken as a whole – be at least as stringent as the proposed federal rule. According to the commenter, given that delegations to date have been based on state regulations that are essentially identical to the federal rules or contain more stringent requirements for particular pollutants (e.g., Hg), the EPA has not had an opportunity to provide the public with an analysis of whether an alternative state program may allow emissions for individual pollutants to exceed by a modest amount the EPA's emissions limits so long as the state's program obtains greater overall benefits. The commenter considers the Utility NESHAP Rule to be the perfect opportunity for the EPA to address this aspect of its delegation authority and provide guidance to the states regarding their demonstration of equivalency.

Commenter 18019 states that under "Boardman 2020" plan, PGE will install pollution controls to reduce interim emissions of nitrogen oxides by about 50 percent and sulfur dioxide emissions by 75 percent. According to the commenter, all coal-related emissions from the Boardman Plant will be reduced to zero with the end of coal operations in 2020. The commenter states that IRP in Oregon is a rigorous process for examining how to meet customer needs at the lowest cost and risk. According to the commenter, IRP provides substantial opportunity for public involvement during the preparation and review of a utility's plan; in its IRP, a utility must assess the performance of candidate resource portfolios under different assumptions about key variables, such as load growth, fuel prices, and environmental costs that may be incurred.

Comment 41: Commenter 17867 states that the EPA should clarify that States may demonstrate equivalency with the EGU MACT through alternative regulation that achieves in aggregate emissions outcomes that are equivalent to the NESHAPs. Specifically, the commenter requests the EPA to confirm that Oregon has flexibility to use its Mercury Rule and the Boardman 2020 Plan to address federal Regional Haze requirements as the foundation for a delegated program. The commenter states that section 112(l) of the CAA, and the corresponding implementation regulations at 40 CFR Part 60, Subpart E, provide that each state may develop and submit to the Administrator a program for implementing the EPA's section 112 HAP program and that the equivalency is not a line-by-line test but rather a demonstration that the alternatives must be holistically equivalent to the Federal requirements. Commenter urges the EPA to make clear that a state-implemented rule for coal units that includes steeper and/or earlier emission reductions of some pollutants (e.g., Hg), identical emission limits for other pollutants (e.g., acid gases), and marginally less aggressive emission reductions for some pollutants (e.g., non-Hg metals or PM), plus a commitment to early cessation of coal firing, along with the necessary work practice standards and elements necessary for compliance assurance, may be considered by EPA as no less stringent, i.e., "equivalent," to the proposed utility NESHAP rule.

c. Concerns over delegation.

Comment 42: Commenter 17648 states that in response to request for comments on whether EPA would be authorized to delegate the section 112 program to states enforcing laws related to EGU emissions and HAP reductions where the program results in greater emission reductions than the EGU MACT but allows a compliance time extending beyond the statutory three year maximum such delegation would "not [be] appropriate unless the state program is at least as stringent as the federal program." The commenter states that the law is "quite clear on this point" and that EPA "does not have the discretion to approve a state program with more lenient deadlines."

d. Implementation.

Comment 43: Commenter 16859 requests that the EPA concurrently publish implementation guidance for this rule to states at the time of new rule issuance. According to the commenter, timely issuance of implementation guidance would facilitate state adoption of the new rule as well as increase state and EPA staff resource efficiency in completing activities related to new rule adoption.

Response to Comments 37 - 43: Responses to these comments are provided in the preamble to the final rule.

15. Need option for percent reduction or increase compliance averaging time.

Comment 44: Commenter 17737 requests that percent reduction should be available as an alternate to a numerical emission rate and could be established to be based on percent reduction from the boiler inlet Hg concentration in a manner similar to the procedure under 40 CFR 60 subpart Da. According to the commenter, the percent reduction could be set at 91 percent, which is the same level as the EPA expects to be achieved nationwide. The commenter states that the numerical limit may be difficult if not impossible to achieve should a source be limited to using coal with a high Hg concentration (above 13 lb/TBtu). The commenter asserts that switching coal sources may not be possible due to the presence of long term coal contracts, mine-mouth configuration, or boiler design. If the Hg coal concentration increases over time, Commenter may not be able to meet the standard with available technology and could be faced with curtailment as the sole compliance option but that this concern could be somewhat alleviated if the compliance averaging time were to be on a 12-month rolling basis.

Commenter 17737 states that ICR data shows some EGUs would achieve a lower emission rate with 75-85 percent removal than others with removal rate in excess of 91 percent. According to the commenter, by not including a percent removal, the EPA is penalizing those EGUs that are not able to obtain coals with relatively low Hg content.

Commenter 17737 states that the EPA's primary rationale for not allowing the percent reduction option is that it may discourage or complicate the use of coal washing as a compliance technology. According to the commenter, this would only be the case if the EPA elected to adopt a percent removal standard in lieu of a numerical limit.

Response to Comment 44: We have addressed comments related to a percent reduction format elsewhere in the final rule record.

16. Cannot meet mercury emission rate on continuous basis.

Comment 45: Commenter 17761 states that after a case-by-case MACT review for Hg, one of their EGUs was expected to achieve a Hg emission rate of 1.70 lb/TBtu (an approximate 83 percent reduction) but that stack testing and monitoring data from the facility has demonstrated significant variability in Hg emissions. The commenter states that operating and monitoring experience with Hg emissions at their EGU suggests that ACI performance is also highly variable and subject to decline based on a number of factors which may necessitate the use of additional solutions to achieve the expected performance criteria. According to the commenter, the inherently low chlorine content of their coal will make it extremely difficult for well-controlled units that utilize their coal to meet the proposed rule's 1.2 lb/TBtu Hg emission rate on a continuous basis. The commenter states that Hg emissions as a function of ACI can vary dramatically over time for reasons that are either not completely understood (e.g., effects of temperature, pressure drop, ammonia slip, SCR catalyst degradation, etc.) or outside the utility's control (e.g., variability of Hg and chlorine content in delivered coal, variability in delivered activated carbon surface area, etc.).

Response to Comment 45: The rule's Hg limit was established consistent with the requirements of CAA section 112(d) and it accounts for variability. As demonstrated by contemporaneous data collected by EGU owners or operators and submitted to the Administrator, approximately 180 EGUs are currently meeting the Hg standard contained in the final rule. To the extent a particular owner or operator believes his EGU's Hg emissions are too high, he can and should take advantage of the three year period before compliance is required to find one or a combination of mercury-reducing approaches that will enable the EGU to meet the Hg emissions limit.

17. Allow portable monitoring equipment.

Comment 46: Commenter 17740 requests the EPA to permit sources to measure concentrations of CO and NO_X in the effluent stream before and after adjustments with portable monitoring equipment. According to the commenter, industry practice is to use portable analyzers located at the boiler outlet duct to measure CO and NO_X during combustion tuning operations.

Response to Comment 46: The EPA agrees with the comment and has modified the rule to allow portable emissions monitoring equipment as acceptable for meeting this requirement.

18. General clarifications needed.

Comment 47: Commenter 17740 states that the EPA should clarify the time ranges listed in 40 CFR section 63.10006(n). The commenter states that the proposed ranges are specified in terms of days, months and years, and that it is unclear whether the EPA is referring to calendar or operating days. Commenter recommends that the EPA adopt operating days or operating quarters. The commenter states that these terms are used routinely by utilities to manage emissions program schedules.

Commenter 19033 states that Table 3 of the the proposed regulation conflicts with 63.1 0006(o) and (p). 63.10006 provides that less frequent testing than annual may be performed, if the criteria in 63.10006(o) and (p) are met, whereas Table 3 requires that annual testing be performed for existing EGUs. To correct this conflict, Commenter 19033 recommends that Table 3 be amended for existing EGUs.

Response to Comment 47: The agency reviewed the commenters' concerns, clarified in section 63.10006(g) that calendar days are the appropriate measurement between stack tests, and corrected Table 3 in the final rule. The agency finds periodic stack testing based on a time period other than calendar days would be confusing for not only the owner or operator but also the agency and the public. Note that the cited table was intended to refer to the annual performance tune-up in the proposed rule. Under the final rule, this has been clarified and the periodic frequency for conducting the tune-up has been modified. See discussion in the preamble.

19. Opposition to the EPA regulation.

Comment 48: Commenter 17768 states that citing the justification for an emissions averaging decision that was provided in a 16-year old rulemaking is insufficient.

Comment 49: Commenter 18477 states that Hawaii's RPS has two significant ramifications for commenter's ability to comply with the proposed rule: first, modification of a large percentage of commenter's generation fleet to use renewable fuel sources has the potential to substantially reduce HAP emissions, but these modifications will not be completed prior to the EGU MACT compliance date. Second, states the commenter, compliance with both the Hawaii RPS and the EGU MACT will require massive capital investments, and it would be unfair to require commenter and its customers to invest in both, particularly when current resource plans indicate the retirement of at least four EGUs with relatively low capacity factors within eight to ten years. According to the commenter, installation of costly control technology on these units to comply with the EGU MACT for the relatively short time frame before retirement would also represent significant economic inefficiency. Commenter estimates that installation of emission control equipment for Hg, HCl, HF, and PM would cost at least $696 million, based on preliminary quotes provided by engineering consultants and equipment vendors. According to the commenter, to date, no control equipment vendor will provide performance guarantees, so this cost estimate does not address the risk associated with failure to comply with the proposed HAP emission limits. The commenter states that it is extremely difficult for companies to develop a cost-effective compliance plan without control equipment vendor guarantees. Vendor guarantees allow companies to plan for prudent capital investments in control technology. Without these guarantees, Commenter is facing the untenable possibility that it will not be able to comply with the proposed standards despite the Company's best efforts and significant capital investments. Accordingly, Commenter urges the EPA to exercise its discretion and establish work practice standards for non-continental liquid oil-fired units.

Comment 50: Commenter 17805 states that it is inappropriate for the EPA to require utilities to expand energy efficiency and demand response programs as an alternative to replacing retired generation when retrofits are uneconomical. The commenter states that based on their resource modeling, the effectiveness and long-term viability of these programs are ultimately dependent on customer participation. According to the commenter, demand response and energy efficiency programs are typically more suited to be replacements for peaking type generation resources than traditional base load generation.

Response to Comment 48 - 50: The EPA disagrees that established precedent, can and should not be used as justification for actions within this rulemaking. As noted elsewhere in this document, we have established a subcategory for non-continental liquid oil-fired EGUs in the final rule. Responses to comments related to the compliance date and emissions averaging are provided in the preamble to the final rule and elsewhere in the final rule record.

CHAPTER 6: IMPACTS AND COST ANALYSIS

6A – Impacts/Costs: Emission Impacts

Commenters: 17174, 17385, 17620, 17689, 17768, 18932

Comment 1: Commenter 17174 asks that the EPA take into consideration the effect of the proposed rule on non-HAP pollutants and the overall air quality and public health improvement to avoid exacerbating air quality issues.

Response to Comment 1: The EPA has determined that the proposed rule will lead to reductions of criteria and HAP responsible for significant adverse health effects and that such reductions will produce substantial public health benefits. Accounting for ancillary impacts is standard practice in benefit-cost assessment since these benefits are a consequence of the rule, regardless of the rule's intended purpose. This rule is expected to achieve substantial $PM_{2.5}$ health benefits resulting from primary PM and SO_2 emission reductions, and these co-benefits have been included in the regulatory impact assessment.

Comment 2: Commenter 17385 asks that the EPA perform additional energy efficiency sensitivity analyses incorporating additional policies. The commenter is pleased with the Integrated Planning Model (IPM) analysis of demand-side energy efficiency impacts on moderating electricity demand and reducing compliance costs. The IPM performed for the proposed rule included only federal appliance standards and utility demand side management programs. The commenter points out that there are other efficiency programs that could be factored in, such as building codes, tax incentives, state and local programs.

Response to Comment 2: The EPA recognizes that the energy efficiency sensitivity conducted does not represent the full array of ongoing policies in this area. The scenario does, however, illustrate in detail the impacts of two of the more significant policy types that are leading to increased investment in end-use efficiency: ratepayer-funded programs and federal appliance standards. These policies are not otherwise represented, for the most part, in the baseline electricity demand forecast from EIA that is used in the EPA's modeling. Building codes and tax incentives may be accounted for to a greater degree in the EIA forecast.

Comment 3: Commenter 17620 argues that although the proposed rule would reduce Hg emissions so that on average the remaining emissions could be approximately 45 lb/unit, emissions of 22 lb/yr/unit cannot be considered trivial or "de mimimis."

Response to Comment 3: The EPA disagrees with the commenter's notion that the goal of the technology-based phase of regulation under CAA section 112 is to reduce emissions to levels that can be considered trivial or "*de minimis*." In fact, there is no such goal described in all of CAA section 112 and today's rule complies with the requirements of section 112(d) to establish technological standards based on what has been achieved in practice by the best performing sources in the category. If the commenter is actually commenting on whether the proposed regulation will adequately protect public health or not, under the requirements of CAA section 112(f), within 8 years after promulgation of this rule, the EPA will determine whether additional regulations are necessary to further limit HAP emissions from EGUs to protect public health with an ample margin of safety.

Comment 4: Commenter 17689 reports that generating and transmission cooperatives provide 41% of all distribution cooperative electric generation needs, of which 80% is coal-fired. The commenter also states that 50% of this coal-fired equipment was constructed under CAA NSPS and more than 60% has FGD or scrubbers to control SO_2 emissions. Also, more than 6,000 MW of the generating capacity has been retrofit with NO_X controls, and SCR. Nearly all of the equipment has low NO_X burner technology, making the aggregate cooperative coal-fired generation newer and better controlled than the overall electric utility sector.

Response to Comment 4: Existing pollution control technologies are available for EGUs to comply with MATS, including controls that reduce Hg, non-Hg metal and and particulates, and acid gas HAP, including HCl.

Comment 5: Commenter 17768 states that the rule is justified based on the co-benefits that stem largely from PM reductions which represent the majority of total quantified and monetized benefits. The commenter argues that is important to account for such co-benefits or ancillary benefits because they are just as significant as countervailing risks and they help to justify the cost-benefit analysis for the regulation.

Response to Comment 5: The EPA agrees that it is valuable to quantify the $PM_{2.5}$ health co-benefits of this rule. Accounting for ancillary benefits is standard practice in benefit-cost assessment since these benefits are a consequence of the rule, regardless of the rule's intended purpose. The EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible, for the purpose of determining the likely impacts, not to justify an action. This rule is expected to achieve substantial $PM_{2.5}$ health benefits resulting from primary PM and SO_2 emission reductions, and these co-benefits are thus an important category to quantify.

Comment 6: Commenter 18932 cites that in 2005 EGUs were responsible for 47% of anthropogenic cobalt emissions in the US. The commenter then cites the negative health impacts of cobalt emissions.

Response to Comment 6: Cobalt emissions will be regulated under the provisions of this rule. Under the requirements of CAA section 112, within 8 years after promulgation of this rule, the EPA will determine whether additional regulations are necessary to further limit emissions of cobalt (or any other HAP) to protect public health with an ample margin of safety.

Comment 7: Commenter 17627 states that the 2005 base year did not include emission reductions that have already occurred as a result of many enforceable federal and state programs. Additionally, the 2016 emissions are predicated off the IPM related NODA dated October 2010 and do not include results from two subsequent NODAs. If the emission estimates were corrected the benefits would not be overstated and it is possible that the rule could not be justified on cost considerations.

Response to Comment 7: The EPA disagrees with the commenter's assertion that the benefits are overstated based on a 2005 base year. The benefits of the rule are computed based on differences between the 2016 baseline and the 2016 policy case, and not the differences from 2005. Therefore, to achieve reasonably accurate estimates of benefits, the most important feature of the EPA's approach is having an accurate projection from 2005 to 2016, so that the emissions reductions and economic downturn referenced by the commenter are included in the future base and therefore not included as part of the benefits of the rule. These impacts are included in both the 2016 baseline and the 2016 policy case and therefore are not captured as benefits of the rule. The EPA diligently included the emissions reductions that have occurred from 2005 to present and the final modeling done for the RIA for this rule is the best available national information to reflect reductions in emissions that have occurred from 2005 to present. The data used at proposal were updated to reflect the comment process on the Cross-State Air

Pollution Rule (CSAPR), for which number eastern states provided detailed updates to the EPA's emissions projection assumptions for EGU, non-EGU point, stationary area, and non-road mobile sources. All of these comments were included in the projections used for this final rule. Furthermore, the comment process for this rule provided an opportunity to make the EPA aware of any other projection changes that were needed for improving our benefits estimates. In the rare instances where such specific comments were made for this rule, the EPA included those reductions in the final 2016 projections. The EPA used the best economic forecasts available at the time the datasets were created. This included the use of Annual Energy Outlook (AEO) of 2010 data in the EGU projections. Other updates to point sources included the incorporation of all known controls in the 2016 baseline, and the inclusion of non-EGU plant closures, federally enforceable emissions reductions, and consent decrees that have happened since 2005. Finally, while the EPA has attempted to provide the most reliable and accurate assessment of the costs and benefits expected to result from implementation of the rule, the commenter incorrectly assumes that the rule must be justified on the basis of cost.

6B – Impacts/Costs: Emission Reductions

Commenters: 17716, 17807, 17884, 17916, 18037, 18425, 18428, 18434

Comment 1: Commenter17716 expresses concern that the EPA's real objectives of imposing the proposed rules is to retire "some of the oldest, least efficient, least controlled units" from further generation and virtually dictates that these units be retired. The commenter states that the EPA's claim that compliance options to reduce criteria pollutants would not have HAP reductions lacks evidentiary foundation. Further, HAP emissions by EGUs have yet to be linked to a cognizable hazard.

Response to Comment 1: The EPA disagrees with the commenter's assertions regarding the motives underlying MATS and the lack of a linkage between HAP emissions by EGUs and public health hazards. The EPA's full statement found in the preamble to the proposed rule does not imply that the EPA encourages or requires EGUs to retire rather than install control equipment but, rather, simply observes that if companies choose to retire the units, it is unlikely to have notable impacts on electricity grid reliability (as shown by EPA analysis). EPA did not state that compliance options for criteria pollutants will not reduce HAP emissions as commenter suggest, only that there may be compliance options (e.g. purchasing allowances in a trading program) which may not lead to HAP emission reductions. We direct the commenter to Section III of the preamble to the final rule for a discussion of the hazards to public health and the environment attributable to EGUs.

Comment 2: Commenter17904 suggests the EPA account for reductions in emissions that have occurred since 2000, and for other expected continuing reductions driven by state and other CAA requirements. The commenter discusses the 26% reduction in annual SO_2 emissions and 62% in NO_X emissions from Texas EGUs from 1995 to 2009 and the fact that nearly 50% of the coal-fired capacity in Texas has FGD systems. The commenter also points out that national concentrations of $PM_{2.5}$ and PM_{10} have dropped 27-30%.

Response to Comment 2: As discussed in the preambles to the proposed and final rules, the EPA agrees that it is appropriate to account for emission reductions achieved by other requirements of the CAA, and the EPA has done so in the technical analyses accompanying this final rule. As documented in multiple technical support documents supporting the final rule, the EPA acknowledges that emissions from U.S. EGUs and other sources would be less than previous years due to controls applied to comply with other EPA regulations. It is standard practice for the EPA to include these emission reductions achieved through promulgated regulations, settlements, consent decrees, and closures in the baseline for future year analyses. Because the CSAPR has significant impacts on emissions from U.S. EGUs, the EPA specifically accounted for CSAPR in the baseline. As such, the EPA has accounted for emissions reductions since 2000 in the analyses supporting the "Appropriate and Necessary" finding, as the commenter suggests. Future year emissions modeling conducted for the final RIA was updated to reflect the most recently available information, and incorporates comments submitted to the docket in response to the proposed rule.

Comment 3: The U.S. relies on coal-fired generation for about half of its electricity. It should be taken into account that the U.S. power sector has reduced air emissions substantially under existing programs. The industry has cut SO_2 and NO_X emissions by 57% since 1980. Mercury has been cut by 40%. This has occurred while electricity use has increased by 85% and electricity from coal generating facilities has tripled. The industry has made significant strides to reduce emissions. Derailing such efforts by piling on additional regulations that many coal- and oil-fired facilities are not able to comply with undermines all this hard work. Not only does the proposed Utility MACT rule in its current form threaten existing generating facilities, it threatens future development of an integral part of our energy portfolio. Please withdraw this proposal.

Response to Comment 3: This regulation does not conflict or interfere with efforts cited by the commenter, but rather builds on them by requiring that coal-fired power plants control highly toxic HAP emissions to a level that is currently being achieved by the best performing EGUs. These levels of control can be achieved with the application of widely available cost effective pollution control equipment and practices. Doing so will save thousands of lives and avoid hundreds of thousands of cases of illnesses including asthma attacks and other respiratory symptoms in children.

Comment 4: Commenter 18037 believes the use of base year 2005 overstates emission reductions from the proposed rule because it ignores the additional reductions realized between 2005 and the present. The commenter also suggests the future emissions are erroneous because they are based on 2010 NODA that have since been updated. Finally, the commenter states that the economic downturn that began in 2008 further reduces actual emissions, making the benefits of the proposed rule less than predicted.

Response to Comment 4: The EPA disagrees with the commenter's assertion that the benefits are overstated based on a 2005 base year. The benefits of the rule are computed based on differences between the 2016 baseline and the 2016 policy case, and not the differences from 2005. Therefore, to achieve reasonably accurate estimates of benefits, the most important feature of the EPA's approach is having an accurate projection from 2005 to 2016, so that the emissions reductions and economic downturn referenced by the commenter are included in the future base and therefore not included as part of the benefits of the rule. These impacts are included in both the 2016 baseline and the 2016 policy case and therefore are not captured as benefits of the rule.

As discussed in the preamble to today's rule and supporting materials, the EPA diligently included the emissions reductions that have occurred from 2005 to present and the final modeling done for the RIA for this rule is the best available national information to reflect reductions in emissions that have occurred from 2005 to present. The data used at proposal were updated to reflect the comment process on the CSAPR, for which number eastern states provided detailed updates to the EPA's emissions projection assumptions for EGU, non-EGU point, stationary area, and non-road mobile sources. All of these comments were included in the projections used for this final rule.

The EPA used the best economic forecasts available at the time the datasets were created. This included the use of AEO of 2010 data in the EGU projections. Other updates to point sources included the incorporation of all known controls in the 2016 baseline, and the inclusion of non-EGU plant closures, federally enforceable emissions reductions, and consent decrees that have happened since 2005. Benefits of the rule are based on emissions reductions projected by IPM modeling to occur in 2016. These projections are based on demand assumptions in 2016 consistent with AEO 2010. The EPA thus disagrees with commenter, and maintains that benefits are not overstated as a result of the economic downturn. See IPM documentation Chapter 3 for further details on electricity demand.

Comment 5: Commenter 18428 discusses well-controlled facilities which have installed control technology that reduces their emissions to area source levels. The commenter believes that applying generally achievable control technology (GACT) to these facilities recognizes the investment already made.

Response to Comment 5: The EPA has addressed comments relating to area sources elsewhere in the preamble to today's rule as well as other portions of this document.

Comment 6: Commenter 18434 states that the proposed rule's output-based emissions limits appear to consider only electrical output, which fails to account for thermal energy produced and used by cogeneration units. The commenter points out that combined heat and power (CHP) and waste heat recovery (WHR) units provide emission-free electricity and efficient heat, making a CHP twice as efficient as traditional power generation and WHR able to produce emission-free power from heat that would have been vented. The commenter provides a figure showing that as much as 63% of total energy inputs are lost as wasted heat with conventional generation so the rule should incentivize CHP and WHR projects by modifying the output-based emissions limits to account for both thermal and electric generation.

Response to Comment 6: The final rule provides 75% credit for thermal output in the definition of "gross output" (this is the value that was proposed). This value has been increased in the NSPS from the original 50% credit a few years ago to recognize the environmental benefit of CHP and has been carried over to the NESHAP.

Comment 7: Commenter 17807 disagrees with the EPA's projection that Polk Power Station Unit 1 CA and Unit 1 CT, which use the IGCC process, would require installation of fabric filters as a result of the proposed rule. The commenter claims that the IGCC process is extremely effective for the removal of PM and that the fabric filter would not be warranted. The commenter requests that the EPA perform an additional review of the modeling process and consider that fabric filters are not feasible technology for the IGCC process and that the technology will not result in emission reductions.

Response to Comment 7: The EPA agrees that fabric filters are not a feasible technology for the IGCC process. Final IPM modeling does not reflect the addition of a fabric filter to IGCC units.

Comment 8: Commenter 17916 supports the proposed rule because it will result in reductions of Hg and other air toxics and criteria air pollutants that cross the national boarder into Ontario. The commenter also cites negative health impacts of such transboundary air pollution.

Response to Comment 8: The EPA thanks the commenter for their support.

Comment 9: Commenter 18425 supports the compliance schedule of the proposed rule because reductions in Hg emissions from Wisconsin's largest utility WE Energies will reduce health impacts to the state's residences.

Response to Comment 9: The EPA thanks the commenter for their support.

Comment 10: Commenter 17884 agrees with the National Mining Association comments and points out that even the EPA's own RIA shows that most of the benefit of the proposed rule will come from reducing SO_2 emissions, and ambient $PM_{2.5}$, rather than HAP. The commenter also believes that the EPA exaggerates the $PM_{2.5}$ emissions, which are already addressed under other CAA programs.

Response to Comment 10: The EPA disagrees with this commenter that $PM_{2.5}$ health co-benefits should be excluded in the estimation of benefits expected by MATS. Accounting for ancillary benefits is standard practice in benefit-cost assessment since these benefits are a consequence of the rule, regardless of the rule's intended purpose (as noted also by Commenter 17768). As such, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible, for the purpose of determining the likely impacts, not to justify an action. This rule is expected to achieve substantial $PM_{2.5}$ health benefits resulting from primary PM and SO_2 emission reductions, and these co-benefits are thus an important category to quantify.

Consideration of ancillary benefits in benefit-cost analysis is directed by OMB Circular A-4 (p. 26, available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/):

> "Your analysis should look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks. An ancillary benefit is a favorable impact of the rule that is typically unrelated or secondary to the statutory purpose of the rulemaking (e.g., reduced refinery emissions due to more stringent fuel economy standards for light trucks) while a countervailing risk is an adverse economic, health, safety, or environmental consequence that occurs due to a rule and is not already accounted for in the direct cost of the rule (e.g., adverse safety impacts from more stringent fuel-economy standards for light trucks)."

It is also directed by the EPA's Guidelines for Preparation of Economic Analyses (p. 11-2, available at: http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html):

> "An economic analysis of regulatory or policy options should present all identifiable costs and benefits that are incremental to the regulation or policy under consideration. These should include directly intended effects and associated costs, as well as ancillary (or co-) benefits and costs."

In line with this guidance, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible. We further note that we were unable to monetize other important benefits, including health benefits of ozone reductions, additional $PM_{2.5}$ health benefits, and direct health benefits of reducing SO_2. If we were able to fully monetize these benefits, the benefits would exceed the costs by an even greater amount than we currently estimate.

The EPA disagrees that the quantified $PM_{2.5}$ health benefits are double-counted with the health benefits achieved by other regulations. The EPA's standard practice for its rules is to estimate, to the extent data and time allow, all benefits of the emissions reductions achieved by a rule *beyond control requirements for other rules*. If this rule was duplicative with other rules, then there would be no additional costs or benefits attributable to this rule.

When the EPA estimates the benefits for rules like MATS, the EPA includes other rules such as the CSAPR in the "baseline." Any emission changes expected as a result of MATS are additional emission reductions beyond those regulations (e.g., CSAPR) that were considered to be part of the baseline. Therefore, the benefits from particle reductions are not double counting – they are real additional health benefits from emissions reductions achieved by MATS alone.

Further, the $PM_{2.5}$ health benefits expected from this rule are not double-counted with benefits estimated in the NAAQS RIAs. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that states may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions.

However, some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in the illustrative $PM_{2.5}$ NAAQS RIA.

In implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ below the PM NAAQS in some areas. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations based on the scientific literature available at the time the standard is set. Although benefits occurring below the standard may be less certain than those occurring above the standard, the EPA considers them to be legitimate components of the total benefits estimate.

6C – Impacts/Costs: Energy Impacts

Comments are addressed elsewhere in this document.

6D – Secondary Impacts

Commenters: 15002, 17810, 17833, 17852, 17868, 17928, 18447, 18477

Comment 1: Commenter 15002 states that while health benefits are the main reason for supporting the proposed rule, they also recognize secondary impacts including improved quality-of-life due to positive effects on crops, plant life, and visibility.

Response to Comment 1: The EPA welcomes this comment and concurs that, although not quantified for this regulation, agricultural, ecological, and visibility benefits are a likely outcome of any action that results in reduced emissions of Hg, $PM_{2.5}$, or other pollutants.

Comment 2: Commenter 17868 notes the possibility of unintended consequences of the proposed rule. For instance, utilities using eastern coal varieties may not be able to meet the requirements and will become more reliant on rail transportation to move western coal to more power plants. Some customers are captive rail customers who must rely on a single railroad to deliver their products. These customers tend to need bulk commodities such as coal, grain or lumber moved, which cannot be moved effectively on-road. The commenter references a study by the Surface Transportation Board (STB) that showed 44% of all tonnage shipped by freight rail is captive, which allows the railroad industry to charge rates 500 to 700% above cost and refusing to provide adequate service to shippers who are captive to one railroad. The commenter provided the following site for more information: http://www.railcure.org/about/about_customer.asp. These increased transportation costs resulting from fuel switching from eastern to western coals may be a reasonable secondary impact that has not been considered.

Response to Comment 2: The EPA modeling fully accounts for the cost of rail transportation, including a consideration of rail competition. This is reflected in the results presented in the RIA. In recent years, railroads have increased coal transportation rates in real terms wherever they have the opportunity. However, rail rates at plants captive to a single rail carrier are now close to the maximum levels prescribed by the STB, which limits the potential for further real increases in these rates. Moreover, between 2004 and 2008, the differential between rates at captive plants and rates at competitively-served plants narrowed. For further information, please see IPM Documentation Chapter 9.3 ("Coal Transportation").

Comment 3: Commenters 17810 and 17852 recognize that the EPA can include non-air quality health and environmental impacts in evaluating beyond-the-floor options, but could not find any reference in the preamble or docket addressing the uncertainties meant in the preamble wording, "[a]s discussed above, the uncertainties associated with non-air quality health and environmental impacts also argue against determining that fuel switching is a reasonable beyond-the-floor option." The commenters note that strong regulatory programs exist at the federal and state levels to protect against non-air quality health and environmental impacts from the production, transport and use of natural gas. Commenter 17852 states that natural gas does not involve issues as complex as those associated with nuclear waste disposal or the risks associated with nuclear accidents, the environmental damage from mountaintop coal, the technical complexity of offshore deep water oil drilling or the need for new high-voltage, long-distance transmission or large land footprints needed for utility-scale renewable energy. This commenter goes on to say that the EPA's record shows that non-air issues apparently do not provide a reasonable basis to discourage fuel switching from coal to natural gas.

Response to Comment 3: The primary basis for EPA's rejection of fuel switching to natural gas was that the switch would not be cost effective, not because of the non-air quality health and environmental impacts. We do note, however, that natural gas extraction through hydraulic fracking is a relatively new process and, while it can be safely undertaken, there remains some level of uncertainty about the level of expertise available to do so in all instances.

Comment 4: Commenter 17833 expresses concern that the proposed rule may impair the reuse of coal combustion residuals (CCR) such as flue gas desulfurization gypsum (FGD gypsum). The commenter urges the EPA to achieve emissions reductions without affecting the FGD gypsum market and points out that ignoring the implications of the proposed rule on CCR, the cost/benefit analysis is incomplete and cannot be properly evaluated. The commenter explains that the use of FGD gypsum to manufacture wallboard rose dramatically since 1995 in part because of the >$1.5 billion expansions and retrofittings done in 1999 to wallboard plants. That investment turned over 85 million short tons of FGD gypsum into building material, and kept it out of landfills. In order to be used by most wallboard plants, FGD gypsum must be formed in a multistage process to precise specifications by the electric utilities. Converting operations to handle a different gypsum material requires plant closure and expensive re-commissioning of the plant, as well as additional costs for transporting natural gypsum, which can approach the cost of the final product. The commenter discusses the 30 years the FGD gypsum industry has spent reviewing literature and performing their own studies to be sure the it does not present human health or environmental concerns and provided the following references: Jessica Sanderson *et al.*, "Fate of Mercury in Synthetic Gypsum Used for Wallboard Production," USG Corp. Report for U.S. Department of Energy (Aug. 2005); Lisa Yost *et al.*, "Lack of Complete Expansive Pathways for Metals in Natural and FGD Gypsum," 16 *Human & Ecological Risk Assessment* 317-39 (2010); Scott Shock *et al.*, "Evaluation of Potential for Mercury Volatilization from Natural and FGD Gypsum Using Flux Chamber Tests," 43 *Envtl. Science & Technology* 2282-87 (Feb. 2009). Gypsum Association's November 19, 2010 comments on EPA's proposed coal ash waste rule: "Hazardous and Solid Management System: Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, Comments Submitted by the Gypsum Association." The commenter states that the loss of FGD gypsum in the manufacture of wallboard would reverse the economic benefits of the last 10 to 15 years and would trigger major market disruption, job loss and price increases at a time when construction industry is vulnerable and reverse the proven environmental benefit of FGD gypsum wallboard.

Response to Comment 4: The EPA does not expect a significant impact on the availability of FGD gypsum due to MATS. IPM analysis shows a potential 6 GW reduction in wet FGD operations, not all of which produce gypsum. This is a small fraction of the total 180 GW of wet FGD projected to operate in the base case, and should have an insignificant impact on the availability of FGD gypsum.

Comment 5: Commenter 17833 sees a lack of information on the potential environmental and economic impacts of these emission limits on the materials and waste streams that would be generated by EGUs to achieve regulatory compliance to be problematic. Without such information the commenter believes the EPA has not performed an appropriate cost-benefit analysis. In particular, the commenter points out that the proposed rule may affect metal levels in EGU wastewater and waste streams. Such downstream impacts must be addressed to adequately assess the costs and benefits of the proposed rule. The commenter believes the narrow scope of each separate media review prevents the EPA from properly assessing the costs-benefit ratio and the proposed rule's potential to complicate or compromise the effectiveness of other proposed rules, and asks that the rules be considered in aggregate.

Response to Comment 5: Waste streams associated with conventional emission controls for NO_X, SO_2, and PM are already well regulated, and the costs of compliance with those regulations were considered as part of the promulgation of those rules. MATS may increase the number of waste streams that will have to be properly managed from two MATS-specific controls: ACI for Hg control, and trona DSI for HCl control. The EPA's IPM modeling for MATS includes additional solid waste landfill disposal cost allowances as part of the variable O&M expenses associated with these controls. The EPA believes that adequate additional waste stream related costs were assigned in the IPM modeling, and, therefore, in the benefit/cost assessment of the MATS rule as well. The EPA is not aware of, and commenter has not provided any information about, any waste streams associated with potential future regulations that cannot be properly evaluated as physically distinct systems, not complicated or compromised by the waste streams already considered for MATS and other existing rules.

Comment 6: Commenter 18447 states that the proposed rule has the potential to force their city to find an expensive landfill solution for its municipal solid waste as an alternative to burning it.

Response to Comment 6: There are multiple options for controlling HAP to the levels required by the final rule and the final regulation does not preclude the use of refuse-derived fuel, nor does the regulation require conversion from coal to gas. Each EGU is able to employ the control strategy that is best suited for that EGU, and there are various pollution controls that can be utilized to reduce emissions without requiring a new fuel source.

Comment 7: Commenter 17928 argues that the higher the level of Trona injection the more CO_2 is produced from reactions with flue gases. The commenter states that, as will the forced oxidation wet limestone FGD operations, the use of Trona may result in the need for additional air permits, and urges the EPA to review and develop permitting procedures to assist in streamlining any permitting delays.

Response to Comment 7: The EPA is aware of the concern that installation of dry sorbent injection (using trona) or some other FGD technologies will result in increased hourly emissions of CO_2. The EPA is currently designing emission guidelines for fossil-fired electric generating units and is taking this into consideration.

Comment 8: Commenter 18477 discusses the Hawaiian RPS laws that may be undermined by the numeric limits in the proposed rule. The commenter explains that Hawaii is moving toward having 70% of its energy use come from clean energy sources by 2030. The commenter explains that the proposed rule will cause Hawaii to prioritize installing controls over investments to increase clean power sources. The commenter describes the Hawaii Clean Energy Initiative designed to implement a fundamental and sustained transformation in the way renewable energy and energy efficiency resources are planned and used in the state. The states RPS law requires that utility sales consist of 15% renewable energy by 2015, 25% by 2020 and 40% by 2030. A main part of the state's strategy to achieve these goals, the commenter explains, is the use of liquid biofuel from renewable sources, which also leads to a substantial reduction in emissions. The commenter asks the EPA to establish work practice standards so that Hawaii has the flexibility to incorporate biofuels and biofuel blends into its power plant operations.

The commenter explains that Hawaiian Electric is a regulated entity that serves an isolated grid, so it does not have economic resources like those available to a merchant generator which can sell power to the highest bidder. The commenter believes the capital investment into control technologies that may not be enough to achieve compliance will impact the ability to continue to implement the biofuels plan and will undermine the environmental benefits of the current plans.

Response to Comment 8: As explained elsewhere in the preamble to today's rule and in this document, based on comments received, the EPA is finalizing a non-continental subcategory for liquid oil-fired EGUs. We believe that this will help address the concerns noted by commenter. The EPA is finalizing emission limitations for this subcategory because it does not believe that work practice standards are applicable in this case as emission testing is feasible and, thus, the provisions of CAA section 112 (h) are not met.

6E - Impacts/Costs: Compliance Costs

Commenters: 16705, 16850, 17003, 17055, 17055, 17174, 17254, 17297, 17400, 17403, 17408, 17627, 17629, 17638, 17648, 17681, 17689, 17697, 17701, 17702, 17707, 17716, 17718, 17731, 17732, 17743, 17751, 17752, 17753, 17758, 17761, 17765, 17775, 17791, 17797, 17810, 17813, 17815, 17816, 17824, 17834, 17842, 17843, 17848, 17857, 17868, 17883, 17884, 17887, 17901, 17911, 17912, 17919, 17929, 18015, 18016, 18021, 18033, 18037, 18038, 18421, 18423, 18424, 18428, 18433, 18434, 18437, 18486, 18497, 18500, 18575, 19114, 19121, 19199, 19212, 19213, 19653, 18023

1. Impacts analyses are flawed.

Comment 1: Many commenters (16705, 17003, 17254, 17400, 17627, 17638, 17681, 17697, 17701, 17731, 17732, 17815, 17824, 17848, 17845, 17868, 17901, 17912, 17919, 18016, 18033, 18038, 18428, 18433, 18437, 18486, 18497, 18575, 19114, 19212, 19213, 18023) question the accuracy of the economic and reliability analysis in the proposed rule because it does not take into account the other major expenditures that will need to be undertaken by the utilities sector in the next 5 to 8 years to comply with up to 8 other regulations. Commenters ask that the rules be considered together, or at least that the Transport rule (CSAPR) be considered in conjunction with the proposed rule. Commenter 17701 encourages multi-pollutant solutions through a robust analysis of all the rules and guidance on cost-effective multi-pollutant responses. Commenter 17815 asks that the EPA especially consider impacts on regions such as Texas which rely more heavily on coal as a major fuel source, and commenter 17919 made a similar request in honor of the nation's "industrial heartland." Commenter 18428 believes the EPA should evaluate the effects of regulations together, as industry does, to plan for compliance in the most cost-effective manner possible. Commenter 18433 also explains that military buildup in Guam will strain resources there, allowing insufficient capital to meet all these requirements. Commenter 18497 states that the industry decisions pertaining to adding needed generation capacity are being exacerbated by the number of new or pending rules and requests a thorough analysis of the combined impacts.

Response to Comment 1: The final CSAPR was included in the baseline analysis for MATS and other finalized air rules and regulations. As explained in the preamble to today's rule, the EPA considered impacts on regional bases as part of its overall analyses, and these are discussed in the RIA and other technical supporting materials.

The Agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: 1) the various EO requirements that the Agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation.

Comment 2: Several **c**ommenters (16705, 17884, 19741) state that the RIA is flawed and underestimates the real impact. Commenter 16705 sees no regional additional impacts in several states and references the White Paper, *EPA's Utility MACT Proposal: High Risk to the Economy and No Incremental Benefit***,** March 15, 2011. Commenter 19741 states that contrary to the retirement assumptions made for the agency's RIA, the NGS is scheduled to operate for a period of time beyond

2015. The commenter is concerned that other faulty assumptions have been made in the RIA, including negative economic impacts.

Response to Comment 2: The EPA recognizes its obligations under EO 13563 to use the best available techniques to accurately quantify both present and future costs and benefits as well as to ensure the objectivity of scientific and technological information and processes used in its analysis. As such, the EPA relies upon guidance from its independent scientific and economic review panels and employs peer reviewed processes and technical literature in completing its analyses. The methodology and assumptions made for the analysis of the rule were included in the RIA that accompanied the proposal.

EPA modeling and projections are intended to be a reflection of possible compliance using specific tools, assumptions, and methodologies that the agency believes to reflect the best and most current information related to the power sector. It is not intended to reflect actual compliance decisions, since those will be made individually be the affected industry based on what makes most sense using existing technologies or other, more cost-effective strategies.

The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis provides a rich characterization of regional issues, and reflects the differences in the power sector composition across those regions. The impact of the rule will vary across regions, and the EPA has presented some of those impacts in the RIA. Overall, coal-fired generation is not expected to change significantly since sources are anticipated to install pollution controls. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 3: Commenter 17629 requests that the calculation and assumptions used to justify the proposed rule be reviewed in detail.

Response to Comment 3: The EPA recognizes its obligations under EO 13563 to use the best available techniques to accurately quantify both present and future costs and benefits as well as to ensure the objectivity of scientific and technological information and processes used in its analysis. As such, the EPA relies upon guidance from its independent scientific and economic review panels and employs peer reviewed processes and technical literature in completing its analyses. The methodology and assumptions made for the analysis of the rule were included in the RIA that accompanied the proposal.

EPA modeling and projections are intended to be a reflection of possible compliance using specific tools, assumptions, and methodologies that the agency believes to reflect the best and most current information related to the power sector. It is not intended to reflect actual compliance decisions, since those will be made individually be the affected industry based on what makes most sense using existing technologies or other, more cost-effective strategies.

The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis provides a rich characterization of regional issues, and reflects the differences in the power sector composition across those regions. The impact of the rule will vary across regions, and the EPA has presented some of those impacts in the RIA. Overall, coal-fired generation is not expected to change significantly since sources are anticipated to install pollution controls. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

2. General support for the proposed rule.

Comment 4: Commenter 16850 commends the EPA for allowing utilities to deploy various control technologies in order to meet the proposed rule's air emissions standards.

Response to Comment 4: The EPA thanks the commenter for their observations.

3. Flexibility in compliance.

Comment 5: Multiple commenters (16850, 16859, 17701, 17732, 17753, 17758, 17797, 17887, 17919, 18033, 18428, 19199, 19653) ask that the EPA avoid one-size-fits-all mandates and minimize costs by allowing flexibility to choose compliance options that best fit the utility's system and customer base. Some of these commenters cite EO 12866 and/or 13563 specifically in asking that the EPA allow more flexibility and consider all rules associated with utilities together. Commenters 17701 and 18428 ask that there be a continued dialogue with federal and state utility and environmental regulators to ensure compliance does not hinder system reliability and minimizes cost impacts on consumers. Commenter 17701 includes the National Association of Regulatory Utility Commissioners resolutions as an attachment. (Attachments - See DCN**:** EPA-HQ-OAR-2009-0234-17701-A1.pdf.)

Response to Comment 5: The EPA has attempted to provide the maximum flexibility to choose compliance options that are permitted by the statute. The EPA does not endorse any specific pollution control technology. The MACT standard is a technology-based standard that is established by considering the maximum emission reductions currently achieved by the best performing EGUs in the category. Individual facilities are free to use whatever technologies, processes, or other means they wish in order to achieve this standard. The MACT standard encourages innovation by spurring companies to develop more effective and efficient methods for achieving the necessary emission reductions.

The EPA has also attempted to provide flexibility for compliance by including, among other things, variability in setting emission standards; provisions allowing emissions averaging among existing sources in the same subcategory to demonstrate compliance; use of surrogates to determine compliance; choice for existing sources to comply with input-based or output-based limits; and guidance on appropriate use of the 1-year extension to comply with the proposed rule if additional time is needed for installation of controls.

Comment 6: Commenter 17648 states that the EPA has appropriately incorporated provisions in the proposed rule to provide regulated EGUs with flexibility to reduce emissions to achieve compliance in the most cost-effective and efficient manner for that particular EGU. The commenter gives the examples of these provisions as being:

1. Work practice standards for dioxin/furan**s** and non-dioxin/furan organic HAP
2. EPA's treatment of variability in setting emission standards
3. Provisions allowing emissions averaging to demonstrate compliance
4. Use of surrogates to determine compliance,
5. Choice for existing sources to comply with input-based or output-based limits
6. Statutory eligibility for a one-year extension to comply with the proposed rule if additional time is needed for installation of controls
7. Provision of affirmative defense to any malfunction.

The commenter calls on the EPA to resist calls to make the proposed rule less stringent on the grounds that it will unnecessarily harm the industry.

Response to Comment 6: The EPA thanks the commenter for these observations.

4. Proposed rule does not properly account for all compliance costs.

Comment 7: Commenter 17758 discusses units that operate and dispatch primarily during times of peak load/peak demand or in emergency situations, times of natural gas curtailment, etc. The commenter explains that the levelized cost of generation for these units is higher than most other forms of electricity generation and would increase with retrofitting with an ESP while offering very little environmental benefit.

Response to Comment 7: The EPA does not believe there will be a significant impact on peaking units as a result of the rule for several reasons. For example, the rule only effects oil/gas steam units and does not cover gas combustion turbine or combined cycle units. Also, the EPA estimated that many oil/gas units will convert, or have already converted, to natural gas. The rule contains "limited use" provisions that will mitigate the impacts on many oil-fired facilities used for peaking and/or reliability purposes. For those units that are expected to continue firing residual oil, many already have existing air pollution control technologies (e.g., electrostatic precipitators) necessary to achieve the emission standards and the remaining units that are not capable of converting to another fuel (e.g., subject to natural gas curtailment) are expected to install cost-effective air pollution control technologies.

Comment 8: Commenter 17055 mentions that their initial assessment did not consider impacts the RICE regulations may have on the potential loss of small units relied upon by many municipalities. Elimination of these units could, the commenter believes, lead to local congestion and require transmission expansion and local programs to meet demand. The commenter believes that working with the industry to institute these changes will help preserve reliable system operations and also allow for a more gradual integration of the costs of compliance that could significantly mitigate reliability issues and sudden increases in consumer electricity prices. The commenter discusses an evaluation of costs due to potential environmental control installations required for a specific group of units if the owners determine that the units require retrofitted controls instead of closure. The estimate of $8.5 billion would be required as initial investments for installation of the necessary controls, a number that may make funding difficult and which will impact the consumer bills.

Response to Comment 8: The agency has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load after retirements are factored in, and industry has also shown that it can build new capacity quickly in response to demand. The EPA believes it has appropriately assessed the potential impacts of this rule, but also recognizes that individual plant retirement decisions for compliance with the rule are made based on individual plant circumstances, and these decisions will require evaluation of local market and transmission issues. The EPA will work with relevant authorities to ensure a smooth transition with this rule. The final rule provides greater flexibility to deal with timing when additional time is needed to address transmission issues arising from reliability issues related to plant retirements. (See the preamble for the final rule.) In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 9: Several commenters (17403, 18016, 18033, 18497) quote the National Economic Research Associates analysis results showing the combined impacts of the proposed rule and the Clean Air Transport Rule. The analysis shows the proposed rule is responsible for the majority of economic impacts that utilities will need to consider when planning for compliance. The commenters present an estimation of compliance costs from this analysis of $17.8 billion in annualized compliance costs and a total cost of $184 billion for 2011-2030, with estimated price increases from 12 to 23% in certain regions.

Response to Comment 9: The EPA modeling of the final rule projects lower price impacts than noted by commenter, and the analyses and results are fully documented in the supporting materials found in the docket for today's rule (See RIA Chapter 3). The EPA has designed a rule that is intended to offer flexibility, to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices. The report cited by the commenter is not transparent with regards to several key criteria, making it impossible for the EPA to fully assess its value as a critique of the RIA.

Comment 10: Commenter 17638 states that the evidence shows that the EPA underestimated the impact of compliance costs of the proposed rule including the following impacts:

1. Electric grid reliability, including transmission
2. The number of coal fired units retired in response to the proposed rule
3. Increases in natural gas prices
4. Increases in electricity rates
5. The impact on national, regional and local economies.

The commenter requests that the EPA respond to the EIA**,** EEI**,** NERC**,** NERA, Credit Suisse, ICF, and Burns & McDonnell and explain how its approach as directed by EO 13563 utilized the best available techniques to quantify anticipated present and future benefits and costs…" The commenter further states that the EPA does not consider the cumulative impacts of all its rules, as shown by wording on page 25058 of the proposed rule that it has yet to consider these cumulative impacts.

Response to Comment 10: The agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: 1) the various EO requirements that the agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, the EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation.

This does not, however, mean the EPA has failed to consider cumulative impacts of the regulation. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the agency does reflect on the broader cumulative impacts of our regulations. In March 2011, the EPA issued the Second Clean Air Act Prospective Report which assessed at the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html.

The direct benefits of the 1990 CAA Amendments and associated programs significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits exceed costs combined with extensive uncertainty analysis suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. This conclusion is likely to also be attributable to this rule as shown in the RIA.

Comment 11: Commenter 17702 questions the solitary estimate for cost of compliance as opposed to the range of monetized benefits for the proposed rule. The commenter believes that the EPA should provide a range of costs based on best and worst case scenarios from the EPA's estimate of 11.1 GW of coal-fired generation being shut-down, to other industry estimates of up to 48 GWs shutdown. The commenter especially questions the EPA's assumption that new natural gas from shale formations will provide sufficient gas to allow fuel switching from coal to gas, despite a recent New York Times article indicating that the amount of gas may be overestimated. (New York Times article June 26, 20 II "Insiders Sound an Alarm Amid a Natural Gas Rush")

Response to Comment 11: The EPA agrees that providing a range of estimates can be one way to present the results of analyses, but it is certainly not the only way, and the EPA is not required by E.O. 13563 to present a range of impact estimates. The EPA has conducted sensitivity analyses that explore key parameters in order to ensure its analyses are as accurate and reliable as reasonably possible, and the corresponding impacts (including cost) can be found in Chapter 3 of the RIA for the rule. To the extent that the background information on which news media relied for their reports is not in the record, we are not able to comment on their veracity. The EPA recognizes its obligations under EO 13563 to use the best available techniques to accurately quantify both present and future costs and benefits as well as to ensure the objectivity of scientific and technological information and processes used in its analysis. As such, the EPA relies upon guidance from its independent scientific and economic review panels and employs peer reviewed processes and technical literature in completing its analyses. The methodology and assumptions made for the analysis of the rule were included in the RIA that accompanied the proposal.

Comment 12: Commenter 17718 states that the EPA's cost-benefit analysis underestimates compliance costs for the commenter's subsidiaries in Kentucky. The commenter cites the costs of over $1.7 billion in retrofits for the subsidiary to comply with the proposed rule, which is expected to translate into a 12.2% to 19.2% rate increase for customers in Kentucky by 2016, depending on their provider. The commenter says that these rate increases do not include costs associated with retiring or replacing units when they become uneconomical in 2016. The commenter states that costs of this magnitude for a utility system with under 8,000 MW of coal-fired capacity shows that the overall compliance costs of less than $11 billion are greatly underestimated. The commenter includes the following reference in a footnote:

> *In the Matter of: Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge***,** KPSC Case No. 2011-00161, Application of Kentucky

Utilities Company (filed June 1, 2011); *In the Matter of: Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan*

Response to Comment 12: The commenter has not provided the necessary information to enable the EPA to evaluate commenter's assertions. The EPA has conducted a detailed national impact analysis of the rule, which includes estimates of impacts to retail electricity prices that the EPA believes, in the absence of contradictory evidence, is reasonable. Moreover, industry has shown in the past that it can install significant pollution controls more cost-effectively than the EPA can sometimes anticipate.

Comment 13: Commenter 17743 states that the proposed rule's standards will apply to all power plants in Oklahoma and is expected to involve widespread installation of new emission control technologies at great compliance cost.

Response to Comment 13: The standards do not cover all power plants in Oklahoma. Rather, the standards apply to coal- and oil-fired EGUs of greater than 25 MW. The EPA has conducted a detailed national impact analysis of the rule, which includes estimates of impacts to retail electricity prices that the EPA believes, in the absence of contradictory evidence, is reasonable. Moreover, industry has shown in the past that it can install significant pollution controls more cost-effectively than the EPA can sometimes anticipate.

Comment 14: Multiple commenters (17281, 17299, 17305, 17306, 17849, 19041, 19123, 19209) express concern that proposed rule may affect the affordability and reliability of their electrical services, and ask for more flexibility.

Commenter 17753 believes that the EPA's estimate of $10.9 billion in annual incremental compliance costs in 2015 are underestimated by half. The commenter asks the EPA to carefully analyze the cost estimates and impact on grid reliability and energy costs and revise the final rule appropriately, or withdraw the rule entirely since it can't be justified technically or economically.

Response to Comment 14: The agency prepared a resource adequacy analysis for the proposed rule and has revised that analysis for the final rule. The agency is also working with FERC regarding the reliability impacts of this rule. The EPA has outlined the various flexibilities associated with the rule, to the extent permitted by the CAA, and the approaches to reliability issues in the preamble. The commenter has not provided evidence demonstrating that the cost estimates are underestimated. The RIA for this rule estimates the annual compliance costs for this rule and the results of these analyses are contained in the RIA documents, in various TSDs prepared for this rule, and the results are summarized in the preamble for this rule. Results of these analyses are available in various level of detail in the RIA and the TSDs, and the detailed results can be found in the docket for this rulemaking and through the official web site for this rule.

Comment 15: Commenter 17761 believes the EPA compliance cost estimation is too low. The commenter cites the $17,000 incremental cost for burner inspection and states that their experience with such inspections gives a very different number.

Response to Comment 15: The EPA is sensitive to the concerns raised by the commenter about the costs of a complete burner inspection requiring a unit outage and internal boiler scaffolding and so we are adjusting the time period between burner inspections not to exceed 36 months. Additionally, a unit that employs neural net combustion optimization software during all periods of normal operation may not exceed 48 months between burner inspections. This allows the burner inspection to be combined with other critical work projects that require internal access to the unit, and reduces the overall cost burden of the work.

Comment 16: Commenter 17765 reports the cost of complying with just the acid gas standard of the proposed rule could easily be over three times higher than the EPA's projection and total almost $12 billion per year. This is already more than the EPA's estimate of $10.9 billion annually for compliance. The commenter goes on to state that private sector estimates of unit retirement are much higher than the EPA's estimate, ranging from 50 to as high as 100 GW in retirements, as opposed to the EPA's estimate of 10 GW.

Response to Comment 16: The EPA disagrees with commenter's assertion that the EPA's cost projection is understated, and maintains that the EPA's incremental cost and retirement projections are reasonable. The EPA also notes that the estimates commenter refers to do not necessarily project impacts based on an identical policy. The EPA has conducted detailed impact analysis of the rule, which shows reasonable cost impacts. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate.

Comment 17: Commenter 17775 reports that a comparison of a Hg-only MACT rule to an all-HAP MACT rule leads to an additional $30 billion in overnight capital expenditures for additional pollution control equipment and an additional $13 billion in overnight capital expenditures for new capacity additions. The commenter mentions that an all-HAP rule results in 5 GW of additional plant retirements when compared to a Hg-only rule.

Response to Comment 17: The EPA disagrees with commenter's characterization of the additional costs associated with today's rule as "overnight capital expenditures," as existing affected sources have up to 3 years to comply with the rule (including the potential for an additional year for the installation of controls), and capital costs are typically amortized over an extended period of time. Comparing the estimated costs of complying with today's rule with those of a Hg-only rule is inappropriate, as the EPA is establishing standards for all HAP emitted from EGUs consistent with CAA section 112. The preamble provides further discussion of the legal requirements that the EPA has sought to comply with in adopting today's rule. The EPA believes, in the absence of contradictory evidence, that the costs imposed by the rule are reasonable. Moreover, industry has shown in the past that it can install significant pollution controls more cost-effectively than the EPA can sometimes anticipate.

Comment 18: Commenter 17813 points out that fabric filters were not included in costs for beyond-the-floor limits, but should be included since it is still unknown if ESPs can meet the PM standard.

Response to Comment 18: The EPA has conducted detailed impact analysis of the rule and includes cost of fabric filters, ESPs, and ESP upgrades. The cost results can be found in the RIA of the rule, and EPA has also included additional information documentation for the Integrated Planning Model.

Comment 19: Commenter 17824 questions the proposed limits on the disposal of coal residuals or ash, which will cost up to $20 billion over the next 50 years.

Commenters 17868 and 17911 express concern that coal ash may be designated as hazardous waste under RCRA (Subtitle C), causing state and municipal governments to feel compelled to remove and remediate the coal ash fill from under buildings, at landfills, and under highways. These costs are not considered in the estimated cost for the proposed rule. The commenter estimates coal ash disposal costs as hazardous waste to range from 5% to 24% of a municipal government's revenues.

Response to Comment 19: These comments are not within the scope of this rulemaking and, thus, the EPA is not providing a response. The EPA is addressing issues related to coal combustion residuals in a separate rulemaking.

Comment 20: Commenter 17824 discusses the proposed ozone limits being lowered from 0.075 ppm to 0.060-0.070 ppm**.** The commenter states that a limit of 0.060 ppm will change 13 of Alabama's 14 monitored counties to non-attainment status and move 85% of monitored counties nationwide to non-attainment status, leading to a cost of $20-$90 billion annually and potentially costs up to 7 million jobs by 2020 and close many of these counties to new business.

Response to Comment 20: This comment is not within the scope of this rulemaking and, thus, the EPA is not providing a response. The EPA is addressing issues related to the NAAQS for Ozone in a separate rulemaking.

Comment 21: Commenter 17824 discusses the regulation of three utilities operating 12 EGUs affected by the proposed rule. Between them the utilities estimate compliance costs of $116.2 million in capital costs, and an expectation that the proposed rule would contribute to the retirement of 2 of the units for a loss of 253 MW. More of these units may be retired, depending on the final rules promulgated for the interrelated regulations currently targeting utilities.

Response to Comment 21: The EPA has designed the rule to mitigate the impacts to the extent possible and finds that a very small amount of the coal fleet could retire in response to the final rule requirements (less than 2% of the coal fleet). Sources have a wide variety of compliance options by modifying operation or installing pollution control technologies and it is unclear whether the commenters have undertaken a rigorous effort to identify and evaluate such alternatives in the course of their analysis.

Comment 22: Commenter 17686 asks that the EPA acknowledge the price increase per MW for compliance as the size of the unit decreases. Commenter 18021 agrees with this additional strain on smaller units, due to the economy of scale. The commenter believes that the EPA did not consider the disproportionately large cost of compliance for small communities, many of which are also suffering economic hardship from falling tax revenue. The commenter cites the Bernstein and EPRI data analysis which chose coal plant retrofits for SO_X control technologies to cost approximately 3 times more per MW for small units. (The commenter includes the following references : U.S**.** Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?, Bernstein Research, 2010., "The Hidden State Financial Crisis," Wall Street Journal online publication, May 18, 2011.)

Response to Comment 22: The EPA's analysis includes scaling factors for pollution controls, depending upon the size of a particular unit. See documentation for the IPM for more detail.

Comment 23: Commenter 17883 owns and operates several coal-fired facilities subject to the proposed rule and sees the proposed Hg limits as difficult to achieve without costly modifications while other facilities will require modifications to meet HCl limits. The costs are estimated to be $60 million for one facility.

Response to Comment 23: The EPA recognizes that the final rule will obligate source owners to install additional controls and has attempted both to minimize unnecessary additional costs and to accurately estimate the costs to the industry. The EPA cannot verify commenter's assertions with regard to any particular unit or facility.

Comment 24: Commenter 18425 expresses concern about the compliance costs of the acid gas controls, which the commenter believes will have a large impact on Indiana coal industry. The commenter considers the conclusion that regulating acid gases is necessary to be incorrect and creates costs greater than what is necessary to protect public health.

Response to Comment 24: The EPA disagrees with the commenter for the reasons set forth in the proposed rule and this final action. The commenter provides no information that causes the EPA to reconsider our conclusions. The EPA has conducted detailed impact analysis of the rule, which shows reasonable cost impacts. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. Comments concerning the necessary finding and section 112(d)(4) standards are addressed elsewhere in the final rule record.

Comment 25: Commenter 19121 considers the EPA's estimated compliance costs to be underestimated since forced retirements and fuel switching are not properly attributed.

Response to Comment 25: The EPA disagrees with commenter's assertion that compliance costs are underestimated or that there is anything in the rule that requires a unit to retire, since retirements are the products of economic business decisions left to the owner. Commenter does not provide detailed information on the "forced retirements and fuel switching" that commenter alleges are not properly attributed.

Comment 26: Commenter 18433 explains the costs for units in Guam and references cost estimates in the Edison Electric Institute report on average retrofit capital cost for ESPs and DSI technology. The commenter references a table created for the 4 units which will be subject to the proposed rule. [See Table 2 in EPA-HQ-OAR-2009-0234-18433-A3**]**

Response to Comment 26: The EPA has included a separate category for non-continental liquid oil-fired EGUs (see preamble).

5. Proposed rule does not properly account for all other impacts.

Comment 27: Commenter 17408 considers the proposed rule and other new or proposed rules focused on the coal industry. The commenter points out that hundreds of thousands of people make a living from coal and cites a Penn State study that showed there to be up to 11 jobs created for every one coal job. The commenter also states that millions of people rely on the electricity that coal provides.

Response to Comment 27: The EPA has conducted detailed impact analysis of the rule, which shows impacts that the EPA judges to be reasonable. The EPA has designed the rule to mitigate the impacts to the extent possible and finds that a very small amount of the coal fleet could retire in response to the final rule requirements (less than 2% of the coal fleet). In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). The EPA has also conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 28: Commenter 17707 discusses the Alabama Power installation of $2.6 billion worth of emission control technologies, including SCRs and scrubbers with reduced emissions from their coal-fired units approximately 65% since 1996. The commenter considers the EPA's new standards to be unreasonable because any benefits would be incremental and outweighed by the costs of compliance. The commenter states that small coal-fired units will not be able to afford upgrades and the proposed rule will result in lost jobs and revenue due to high compliance costs.

Response to Comment 28: The benefits of this rule encompass the benefits of Hg reductions and co-benefits to health achieved via $PM_{2.5}$ reductions. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impacts of the rule on the regulated sector are small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. The EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period if the source needs that time to install controls. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 29: Several commenters (17716, 17731, 17797, 17810, 18929) discuss the assertion that energy efficiency policies reduce the total cost of implementing the proposed rule. Commenters 17716 and 17731 point out that the proposed rule has no effect on whether efficiency savings are realized and these savings do not serve as offsets to the higher compliance costs imposed by the proposed rule. Commenters believe energy efficiency had only a modest, indirect effect in later years and references Table 23, lines 3 and 4 on page 25074 of the proposed rule, which shows incremental annual compliance costs with and without energy efficiencies. The compliance cost is the same for both options in 2015, and changes only from $9 billion (with) to $10 billion (without) in years 2020 and 2030. The commenters also disagree with claims that energy efficiencies will offset rate hikes. The commenters believe changes in the amount of energy used are more likely to be due to the economic necessity of using less energy to save money following price increases, rather than due to energy efficiency improvements.

Response to Comment 29: The EPA has designed a rule with considerable flexibility in accordance with the requirements of CAA section 112. Within the limitations established by the rule, the final choice of methods for reducing emissions remains at the discretion of the owner or operator. However, the EPA believes energy efficiency measures can be a complement to this rule, and can be an important tool in helping address emissions. The EPA has not included all the likely additional energy efficiency measures that may occur by 2015, but will continue to pursue energy efficiency improvements throughout the economy, along with other Federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements.

Comment 30: Several commenters (17791, 18421, 18434) acknowledge that the proposed rule recognizes the role of energy efficiency in reducing compliance costs and notes that the EPA cannot mandate energy efficiency policies. The commenters quote the EPA estimate that energy efficiency could reduce costs of the proposed rule by $2 billion in 2015, $6 billion in 2020 and $11 billion in 2030. Commenter 18434 believes that since energy-efficiency investments are concentrated in densely populated areas with highest demand, even limited policies in the existing sensitivity analysis are likely to have greater benefits than estimated. This commenter also states that both state and federal policymakers are making progress in the area of energy efficiency, making the potential for fuel savings through efficiency greater than that estimated. The commenter urges the EPA to modify the analysis to reflect the State Energy Efficiency Action Network recommendations. The commenter understands that the EPA cannot mandate efficiency programs, but it can urge state regulators to view compliance extension requests more favorably from facilities making efforts to advance efficiency.

Response to Comment 30: The EPA agrees that energy efficiency measures can be a complement to this rule and can be an important tool in helping address emissions. The EPA has not included all the likely additional energy efficiency measures that may occur by 2015, but will continue to pursue energy efficiency improvements throughout the economy, along with other federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements.

The final rule provides 75% credit for thermal output in the definition of "gross output" (this is the value that was proposed). This value has been increased in the NSPS from the original 50% credit a few years ago to recognize the environmental benefit of CHP and has been carried over to the NESHAP.

Comment 31: Some commenters (17689, 17824, 17887, 17912, 18021, 18037, 18500, 19212, **18023**) express concern about the combination of multiple regulations currently proposed and the limited timeframe for compliance with these proposed rules. Commenter 17689 mentions the NSR and permitting requirements for the installation of control technology, and the fact that this process can take over a year. This would be likely to create a backlog at state agencies, making it nearly impossible to meet the compliance timeline. Commenters 17824 and 18023 in particular cite the EEI study that found 50% of the U.S. coal fleet may be unavailable by 2015 as a result. Commenter 17887 points out that many generators will need the same equipment and specialized labor, leading to price pressure and equipment shortages due to the tight timeline. Commenters 17912 and 17689 question the need for outages to install equipment for multiple rules during the same timeframe, which will require more time than is allowed under these rules. The commenter sees this as particularly problematic for IPPs, because they typically do not have enough EGUs to avoid reliability issues with such outages and will have to pay to replace the capacity. Commenter 18037 explains the difficulties for planning without time to consider economies of scale, or co-benefits that could be realized by the installation of one type of equipment as opposed to several. Also, this commenter discusses the physical space constraints for some plants looking to retro-fit control equipment. To remain competitive, facilities must add control equipment as it is needed, and adding equipment before it is necessary is financially imprudent.

Response to Comment 31: One of the purposes of developing the NSPS and MATS rules in tandem was to facilitate more cost-effective compliance planning by affected source owners and, while the EPA acknowledges concerns expressed by the commenters, it continues to believe that it has sought to minimize any hardships associated with compliance. As part of the analysis supporting the rule, the EPA has included a TSD on feasibility of installing pollution controls, and additional detail on timing can be found in the preamble.

Comment 32: Commenter 18015 believes as an owner/operator of three large coal-fired power plants that the proposed rule will have significant impacts on the company's operations.

Response to Comment 32: The EPA has conducted detailed impact analysis of the rule, which shows impacts the EPA has judged to be reasonable. The EPA has designed the rule to mitigate the impacts to the extent possible. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 33: Commenter 18486 urges the EPA to discontinue the regulation of power plants until it has studied the combined impact of current and pending rules on natural gas rules and how those impacts affect agriculture.

Response to Comment 33: The EPA is subject to a Consent Decree in the matter of *American Nurses Ass'n v. EPA*, 08-2198 (D.D.C.). That decree requires the EPA to sign the final MATS rule by December 16, 2011.

Comment 34: Commenter 18023 reports that the roughly 400 GW of capacity affected by the proposed rule and other pending or new regulations are vital to adequate electricity supply and provide substantial generator-supplied frequency control capability to the bulk power system. The commenter states that the aggregate impact of these rules will require unprecedented levels of generation and transmission construction in a short time period and could force industry to operate in uncertain conditions. System changes in the electricity industry must be evaluated in advance so the system can be planned and operated such that the causes and effects can be understood, and costs and problems minimized.

Response to Comment 34: The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) and that coal-fired generation will not change significantly. The agency has also assessed resource adequacy, and has determined that there is sufficient excess capacity in existence that will help serve load. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues.

6. Coordination of rules regulating similar pollutants.

Comment 35: Commenter 17627 states that NSPS requirements in the proposed rule have the potential to retire coal generation without an economical replacement, increasing costs to the public. The commenter asks that the proposed rules that deal with the same pollutants be coordinated so that one is implemented and given time to realize benefits before another program controlling the same pollutants are implemented. The commenter believes this approach would produce the desired environmental and human health benefits while maintaining system reliability and minimizing costs.

Response to Comment 35: To the extent possible, the EPA has coordinated the rulemakings. However, CAA section 112 provides statutory compliance times which preclude doing much of what commenter seeks. Other comments on the compliance time issue are responded to elsewhere in the final rule record.

Comment 36: Commenters 17681 and 17901 state that the EPA's initiatives will each have an impact on electricity cost and transmission and together the compliance costs could disproportionately impact the elderly, minorities and low-income citizens. The commenters consider the prominent rules at issue to include:

(a) 2010 NAAQS for NO_2**;**
(b) 2010 NAAQS for SO_2**;**
(c) 2011 NAAQS for ozone;
(d) 2011 NAAQS for $PM_{2.5}$;
(e) 2011 Cross State Air Pollution Rule (CSAPR);

(f) 2012 Revisions to the CSAPR;
(g) 2011 Industrial Boiler MACT;
(h) Regional Haze Rule;
(i) GHG PSD and Title V permitting;
(j) GHG NSPS;
(k) 2010 revisions to 40 CFR Part 63, subpart ZZZZ;
(l) 316(b) cooling water intake structures;
(m) Steam Electric Effluent Guidelines;
(n) Numeric nutrient criteria;
(o) Total Maximum Daily Load rules; and
(p) Coal Combustion Residuals.

The commenters also ask that the EPA honor EO 13563 by considering these rules together. Commenter 17901 estimates that the combined rules will directly impact approximately 400,000 MW or oil- and coal-fired generation, or 40 to 50% of national electricity generation.

Response to Comment 36: The EPA acknowledges that elderly, minority and low-income populations are overrepresented among those persons who live in close proximity to coal-fired power plants. For that reason, the EPA expects that elderly, minority, and low-income population groups would benefit disproportionately from the reduced emissions that will result from the rulemaking. The agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: 1) the various EO requirements that the agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, the EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation.

This does not, however, mean EPA has failed to consider cumulative impacts of the regulation. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the broader cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed at the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html.

The direct benefits of the 1990 Clean Air Act Amendments and associated programs significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits exceed costs combined with extensive uncertainty analysis suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. This conclusion is likely to also be attributable to this rule as shown in the RIA.

Comment 37: Commenter 17751 quotes EO 13563 and EO 13576 about overlapping, redundant or inconsistent requirements as well as doing everything in the Government's power to stop wasteful practices. The commenter questions the EPA's choice to impose several regulations instead of one. The commenter quotes the EPA study that states implementation of the 1997 NAAQS for ozone and PM may lead to Hg reductions, but went on to say that the reductions could not be sufficiently quantified. The commenter questions the validity of the statement and asks the EPA to develop and implement a procedure to provide reasonable upper and lower bound estimates of PM reductions likely to be achieved through state SIP programs. The commenter acknowledges that the estimates may not be completely accurate, but believes providing an estimate would be more helpful than not including one. The commenter believes that by not making a prediction, the EPA is essentially assuming the benefits of the state SIP programs on Hg will be zero, which is not credible and leads to inflated benefit estimates of the proposed rule.

Response to Comment 37: Where the opportunity is presented, the EPA seeks to coordinate efforts to comply with multiple CAA requirements. In implementing rules such as the MATS, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the NAAQS for PM and ozone in some areas and assist other areas with attaining these NAAQS. Although both RIAs calculate PM and ozone costs and benefits, it is important to note that there are key differences in the design and analytical objectives of a NAAQS RIA and one for a rule such as MATS. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that states may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. Some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in the illustrative $PM_{2.5}$ and ozone NAAQS RIA, but these effects are only counted once when considering cumulative costs and benefits.

Comment 38: Commenter 18033 addresses the EPA's decision to wait until the NSPS for GHG emissions rulemaking before considering coordinated control strategies for EGUs. The commenter considers this approach to be too late, since many utilities much begin complying with CSAPR within the next few months and will have only 3 years to comply with the proposed rule once it is finalized. The commenter states that the EPA is obligated to help the regulated community plan for all interrelated regulations and cumulatively assess the societal impacts of these regulations, which has not been done in this instance. The commenter sees the combined regulations impacting American competitiveness as increased prices undermine businesses ability to compete and sending businesses and jobs overseas.

Response to Comment 38: The EPA believes that by proceeding with the rules being adopted today, which were developed with explicit consideration of the impacts of CSAPR, it is striking a reasonable balance between seeking necessary protections of public health and coordinating efforts for the NSPS and MATS to minimize unnecessary costs to industry. Rules under development for GHG emissions will fully consider requirements adopted in today's regulations and seek to minimize or eliminate disruptive impacts on compliance planning and implementation.

7. Impacts on tribal nations.

Comment 39: Commenter 17732, as a tribal nation and small government landlord of affected EGUs, states that the EPA is obligated to consult with the commenter and analyze the economic impacts to the commenter in promulgating the proposed rule. The commenter further states that EPA is required to tailor the proposed rule so that the costs of compliance for plants on the commenter are achievable within a reasonable timeframe, while taking into account the unique challenges of the plants for this and future rulemakings. The commenter explains that compliance costs to meet BART have the potential to impact the commenter's economy significantly. The commenter is concerned that the proposed rule will create a recurring threat of severe reductions in the revenue received from the power plants and their supplying mines. The commenter explains that FCPP and NGS are subject to proposed BART determinations and that EPA, Region IX, proposed an Alternative Emission Control Strategy ("AECS"), a better-than-BART determination for FCPP. The AECS takes into account the FCPP proposal to shutdown Units 1, 2 and 3. The loss of this total net capacity of 560 MW by 2014 would result in 100% control of NOx, $S0_2$, PM, Hg and other hazardous pollutants from these EGUs, which would significantly reduce emissions from FCPP. Currently, the EPA, Region IX, has delayed proposing BART for NGS until at least December, 2011, pending consultations with stakeholder tribes. After publication of the ANPRM for BART, the commenter recommended a phased approach to emissions controls for FCPP and NGS, and suggested that the EPA consider the multiple interests at stake, including the significant economic interests of the commenter. The commenter asks that the EPA analyze the impacts from these rulemakings and provide flexibility for compliance scheduling so that FCPP and NGS, upon which the commenter relies, can continue operations.

Response to Comment 39: Landlords of affected facilities are not included in the definition of an affected small entity and, thus, were not included in the EPA's analysis of small entity impacts. The EPA conducted multiple consultations with the tribes, including the Navajo Nation and has sought to be responsive to concerns raised in those consultations. As to comments about an obligation to tailor the rule to the Navajo Nation's economy, the CAA imposes certain specific requirements and the EPA does not believe that it permits tailoring to the extent that appears to be requested by the commenters.

With respect to compliance, the EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their title V permitting authority if the source needs that time to install controls. CAA section 112(i)(3)(B).

8. Methodology and assumptions in calculations.

Comment 40: Commenter 17810 recognizes that the EPA can consider costs as part of the beyond-the-floor analysis, but asks that the EPA clarify the methodology and assumptions used and expand the analysis to include potential cost effectiveness of repowering coal-fired units as natural gas combined cycle units. The commenter provides recommendations on the technologies used in combusting natural gas, fuel costs and pipeline costs. (Insert included in original letter 17810-A1_Table2Page17.doc.) The commenter questions the pipeline construction costs for converting existing coal units to natural gas since they do not accurately reflect the costs a unit owner would face in repowering to natural gas. The commenter cites an example case in Oklahoma for which the EPA's methods result in cost estimates 20 times greater than a more site-specific estimate. The commenter offers a table showing two example coal-to-gas repowered units for which the EPA estimate is approximately $375 million while the total costs using Navigant estimates are $52 million. The number of pipeline laterals seems to create the largest estimate differences. The commenter notes that the EPA estimates seem to show laterals cannot draw more than 10% of the mainline capacity, but the reason for this assumption is not shown.

Commenter 17810 also requests clarification on the "Incremental Fixed Costs" equation and any assumptions made about plant life. The commenter questions whether the manner in which the EPA evaluated these costs is scientifically sound, since the report only includes costs associated with retrofitting a 303 MW unit at static technology, pipeline and fuel costs. The commenter notes that no information on why the EPA chose to estimate costs for only one unit or chose a 303 MW unit. Since these costs can vary greatly depending on the unit size, the commenter suggests that the EPA conduct a sensitivity analysis showing the costs of retrofit options for different size units and fuel price points.

Commenter 17810 suggests the EPA analyze the costs of retiring existing coal units and creating new capacity on sites closer to pipelines. The commenter asks that the EPA include an evaluation of repowering to natural gas combined cycle units in the evaluation of the cost of control options since there are efficiency advantages over boiler-based technologies.

Response to Comment 40: The EPA disagrees with commenter's assertion that NGCC repowering and coal-to-gas (CTG) switching at existing coal plants were not adequately evaluated. The EPA's IPM modeling inherently considers new NGCC capacity as an alternative to continued operation of existing coal units, with and without retrofit air emission controls. The EPA's IPM modeling for MATS also offers a CTG option for existing coal units, wherein the CTG capital cost is properly scaled to the existing unit size. The EPA's TSD discussion of CTG used an average unit size of about 300 MW only to illustrate the approximate average economics of alternative (and collective) control options, including CTG. The EPA has fully documented its peer-reviewed methodology and assumptions for assessing the impacts of this rule, which can be found in the documentation for IPM (http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html). The documentation includes generation technology assumptions, pollution control cost assumptions, fuel supply assumptions, and financial assumptions governing the power sector.

9. Energy efficiency reduces compliance costs and emissions.

Comment 41: Commenter 17843 appreciates the Energy Efficiency Scenario that illustrates how the costs of the proposed rule can be lowered through energy efficiency investments instead of retrofitting pollution controls or building new generation units. The commenter points out that energy efficiency also enhances reliability as it encourages retirement of the least efficient units as demand decreases. The commenter points out that some states are pursuing aggressive programs and directing investments for energy efficiency with proven results. The commenter cites the following article: Regional Greenhouse Gas Initiative, Inc. (RGGI, Inc.). "Investment of Proceeds from RGGICO2 Allowances."RGGI, Inc. (February 2011), at http://www.rggi.org/docs/Investment_of_RGGI_Allowance_Proceeds.pdf (accessed July 8, 2011).

Response to Comment 41: The benefits of energy efficiency policies are discussed in the preamble. These impacts include reduced need for construction of new generating capacity as well as reduced need for construction of emissions controls such as FGDs. The EPA has designed a rule with considerable flexibility in accordance with the requirements of CAA section 112. The EPA believes energy efficiency measures can be a complement to this rule, and can be an important tool in helping address emissions. The EPA has not included all the likely additional energy efficiency measures that are likely to occur by 2015, but will continue to pursue energy efficiency improvements throughout the economy, along with other Federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements.

Comment 42: Commenter 17929 states that new boilers can reduce emissions by incorporating energy-efficient designs that allow them to use less coal to produce the same amount of electricity. The commenter points out that a boiler operating at 40% efficiency will use 10% less coal to produce the same amount of power than if it is operated at 36% efficiency.

Response to Comment 42: The EPA generally agrees and thanks the commenter for their observation.

Comment 43: Commenter 18421 discusses the role of energy efficiency in reducing costs and preserving reliability. The commenter cites studies by McKinsey and Company, MIT's Innovations, U.S**.** DOE and others that see benefits to more efficient processes and improved demand-side energy efficiency programs. The commenter compares the Toxics Rule Case without energy efficiency to the Toxics Rule Case with energy efficiency and found that the efficiency policies reduce the need for new capacity by 0.3 GW in 2015, by 8.5 GW in 2020, and by 39.8 GW in 2030. The commenter also notes that the reductions lower annual average electricity demand growth. The commenter cites a 2009 study by the American Council for an Energy-Efficient Economy which found by looking at programs in 14 states that efficiency programs by the utility sector cost one-third less than investing in new generation of any type. A report by Synapse Energy Economics reinforced the finding and showed that the highest cost per kWh saved through energy efficiency was 3 cents, compared to the national average of 9 cents per kWh of delivered electricity. (The commenter provided the following references as footnotes: RIA8.13 Illustrative End-use Energy Efficiency Policy Sensitivity RIA8 Appendix D. For example, McKinsey& Company, "Unlocking Energy Efficiency in the U.S**.** Economy," (July 2009), Hannah ChoiGranade, Jon Creyts, Anton Derkach, Philip Farese, Scott Nyquist, and Ken Ostrowski **(**http://www.mckinsey.com/clientservice/electricpowernaturalgas/downloads/us_energy_efficiency_full_report.pdf) and Electric Power Research Institute, "Assessment of Achievable Potential of Energy Efficiency and Demand Response Programs in the **U.S**. (2010-2030)," (January 2009), **(**http://www.edisonfoundation.net/iee/reports/EPRI_SummaryAssessmentAchievableEEPotential0109.pdf).American Council for an Energy-Efficient Economy, *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs*, September 2009. 105 States evaluated are: California, Connecticut, Iowa, Massachusetts, Minnesota, Nevada, New Mexico, New Jersey, New York, Oregon, Rhode Island, Texas, Vermont, and Wisconsin Synapse Energy Economics, Inc, *No Need to Wait: Using Energy Efficiency and Offsets to Meet Early Electric Sector Greenhouse Gas Targets*, May 2009.)

Response to Comment 43: The studies cited provide information on the cost-effectiveness of energy efficiency policies that are generally consistent with the sources cited for the EPA analysis.

10. Fuel switching.

Comment 44: Commenter 18423 questions the EPA's statements and calculations pertaining to fuel switching as a regulatory option. The commenter questions the lack of consideration for new gas units to replace coal units and the rejection of fuel switching as an option due to the lack of supply/availability of natural gas and the cost. The commenter reviews the capital costs calculated by the EPA and concludes that the ratio of cost of fuel switching from coal to gas is 18-53% higher than the alternative, rather than 4 to 22 times the cost of the alternatives. The commenter sees an error in the EPA's calculations because it does not consider that fuel switching to natural gas removes the expense of coal for retrofitted units. The commenter refers to the "Base and Incremental Fuel Costs" table created by the EPA in which it appears the cost of coal at $22.4/MWh is not included in the control technology refit scenario comparisons.

Response to Comment 44: The EPA disagrees with commenter's assertion that EPA calculations comparing the coal-to-gas (CTG) boiler conversion option to other retrofit control options incorrectly included the base cost of coal fuel (as well as gas fuel) in the CTG incremental fuel cost. The EPA incremental cost calculations are correct. Furthermore, EPA's IPM analysis has fully considered and included the multitude of compliance options available to sources. The IPM analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) and that coal-fired generation will not change significantly. The agency has also assessed resource adequacy, and has determined that there is sufficient excess capacity in existence that will help serve load. The EPA modeling fully reflects the costs of competing fuels, and the results can be found in Chapter 3 of the RIA. The EPA responds to comments associated with requiring units to switch to natural gas in response to comments on the beyond the floor analysis elsewhere in the final rule record.

11. Miscellaneous.

Comment 45: Commenter 17752 expresses concern about the risk of noncompliance for early action. The commenter explains that if controls are installed based on the proposed rule do not achieve the reductions required by the final rule, the unit owner faces enforcement penalties because there is not market in which to buy allowances to cover the compliance shortfall. The commenter also notes that utilities contemplating retrofits to units in rate-regulated states run a risk of non-recovery if they make capital commitments before the final rule is issued.

Response to Comment 45: The EPA is allowing a 3-year compliance timeframe for existing sources affected by the rule, and there are also conditions under which extensions could be granted (see preamble for additional discussion on timing.

Comment 46: Commenter 19114 questions the lack of documentation to support conclusions about the amount to capacity that would or would not need to add fabric filters to meet the proposed PM limits. The commenter requests full emission data and projections along with details on which technologies, controls and units are likely to meet the HAP standards with or without the use of a fabric filter.

Response to Comment 46: See Documentation Supplement for EPA Base Case v.4.10_MATS – Updates for Final Mercury and Air Toxics Standards (MATS) Rule for a detailed description of the assumptions used by EPA regarding fabric filter retrofits in the modeling done in support of the final rule.

Comment 47: Commenter 17701 points out that their organization members have a history of supporting cost-effective energy efficiency measures and are leaders in reducing emissions, increasing energy efficiency and promoting renewable and clean energy sources.

Response to Comment 47: The EPA thanks the commenter.

Comment 48: Commenter 18424 points out that the estimates of cost of compliance show much of the cost is associated with acid gas controls, which the commenter believes will have a strong impact on Indiana coal industry. The commenter considers the decision to regulate acid gas to be incorrect because the costs are more than what is necessary to protect public health.

Response to Comment 48: The EPA's response to comments concerning the regulation of all HAP emitted from EGUs is addressed elsewhere in the final rule record.

6F – Control Technology Cost Assumptions

Commenters: 16469, 16705, 16826, 16849, 17296, 17386, 17400, 17408, 17620, 17621, 17622, 17623, 17627, 17648, 17655, 17682, 17702, 17721, 17731, 17734, 17736, 17754, 17756, 17757, 17758, 17761, 17765, 17770, 17775, 17790, 17796, 17807, 17810, 17821, 17840, 17842, 17868, 17869, 17881, 17885, 17904, 17911, 17912, 18017, 18033, 18037, 18421, 18433, 18437, 18447, 18484, 18500, 18575, 19114, 19122, 19213, 19536/19537/19538, 18023

1. Coal ash/coal combustion residuals.

Comment 1: Many commenters (16705, 17702, 17400, 17754, 17758, 17770, 17775, 17821, 17868, 17881, 18437, 18500, 18575, 19213) question the assumption that facilities will be able to sell or trade coal ash/coal combustion residuals despite possible changes that could occur in the sodium content of the ash due to new emission control technologies being required. Increased sodium could render the ash unable to be sold and lead to coal ash management costs in addition to lost revenue. Commenter 18500 points out the EPA identified 93 GW of capacity that it expects to utilize ACI to meet the proposed requirements. This commenter states that the beneficial reuse market for fly ash tops $2 billion annually, so the use of ACI would risk eliminating the market and forcing landfilling of these residuals at a dramatic increase of operating cost. The commenters believe these considerations should be included in the costs.

Comment 2: Commenter 17754 states the limitations placed by the proposed rule on the sale of coal ash potentially interferes with broader environmental considerations because they may impede the continued beneficial use of coal ash for the reclamation of abandoned mining lands.

Comment 3: Multiple commenters (17621, 17758, 17754, 17775, 17821, 17868, 17881) discuss the use of sodium-based DSI and the impact it could have on marketability and beneficial use of fly ash in concrete, wallboard, asphalt products, bridge construction and mine reclamation. The commenters state that around 134 million tons of coal combustion residuals are currently generated every year and 56 million of these are recycled in these applications. The loss of these uses, the commenters say, will cause the coal ash/coal combustion residuals to be disposed of instead of used beneficially, causing economic, operational and environmental burdens. Coal-based facilities will need to expand existing disposal units or construct new ones, which can take several years and cost millions of dollars per unit not accounted for in current cost estimates.

Comment 4: Some commenters (17758, 17775, 17821, 17868, 17911) explain that fly ash must meet product specifications to be used in certain applications to assure high-quality products, such as an appropriate alkali limit for use in concrete to avoid expansion and cracking. The commenters explain that the sodium-based sorbent injection technologies cause fly ash to exceed the appropriate alkali criteria, exceed necessary carbon content, and are soluble, making it unsuitable for use in ready-mix concrete. The commenters go on to explain that solubility is also increased, making it unsuitable for other established uses, such as mine reclamation. The commenters point out the previous testimony by the EPA about beneficial uses of coal ash/coal combustion residuals saving virgin resources and reducing energy consumption, reducing GHG emissions and the need for land disposal and ask that the forfeiture of environmental benefits of coal ash/coal combustion residuals be assessed and considered in overall policy evaluation. **Comment 5:** Commenter 17821 reports that 3 million tons of coal ash/coal combustion residuals is beneficially reused by their organization annually, but this will end if they must install sodium-based DSI or ACI. This will lead to loss of jobs and an economic impact on the utility plant and end users of the coal ash/coal combustion residuals.

Response to Comments 1 - 5: Multiple commenters declare that DSI and ACI controls contaminate coal ash/coal combustion residuals, thereby rendering the co-mingled material unmarketable. The EPA notes (from the comments submitted) markets purchased 56 million tons of the 134 million tons of coal ash/coal combustion residuals – a fraction of the total coal ash/coal combustion residuals generated. Removal of this entire quantity due to contamination from the marketplace can be adequately satisfied by the remaining coal ash/coal combustion residuals produced. By the comments submitted, not all coal ash/coal combustion residuals generated is sold; rather a sizable portion (58 percent) is disposed. Moreover, the coal ash/coal combustion residuals marketplace sets specifications for allowable contaminate levels; depending upon ACI and DSI flow rates, this may or may not render ash unmarketable. The EPA concludes negligible impacts to downstream coal ash/coal combustion residuals end-users market.

As for coal ash/coal combustion residuals producers, only 42 percent of ash sells to the market (56 million tons of 136 million tons) thereby making it a minor revenue stream for an EGU. As mentioned before, depending upon ACI and DSI flow rates in conjunction with coal ash/coal combustion residuals buyer's specification, the ash may retain marketability. As for contaminated ash, a station's owner may install a secondary particulate capture device dedicated to removal of DSI absorbents or activated carbon downstream of existing PM equipment. This second PM device preserves coal ash/coal combustion residuals ash sales while reducing waste volume generated. Finally, for those EGU's electing to dispose of the contaminated ash, the EPA models this cost at $50 per ton for disposal costs. The EPA believes multiple options exist for EGU owners to implement the most economical compliance action for adhering to MATS regulation.

Several commenters are concerned that sorbent injected by DSI and ACI controls will contaminate CCR, particularly fly ash, to such an extent that the co-mingled material is unmarketable. The EPA has modeled DSI and ACI in a manner that includes the cost of an additional secondary PM collection device, a fabric filter (FF), dedicated to the collection of injected sorbent downstream of the existing PM collection device. This modeling assumption incurs the additional cost of a FF on most DSI retrofits and on many ACI retrofits, in order to allow uncontaminated fly ash captured in the existing PM collection device to remain marketable. Given that DSI and ACI remain economic for many units even with this conservative cost assumption, the EPA concludes that there will likely be minimal impacts to the downstream CCR end-user market. Furthermore, although the EPA based the costs and performance estimates of DSI on use of Trona, the use of other reagents can mitigate or even avoid this problem altogether. Sodium bicarbonate has been shown to be more effective than Trona, which would reduce the sodium content of ash considerably. Activated lime hydrate is another alternative to Trona that would avoid the concern about sodium solubility altogether. The CCR marketplace sets specifications for allowable contaminate levels and these specifications vary based upon the ultimate purpose of the fly ash. Depending upon ACI and DSI flow rates, the fly ash may or may not be rendered unmarketable. In some cases the fly ash will remain acceptable for the original purpose; in some cases it may no longer be acceptable for the original purpose, but it will be suitable for other purposes. Regarding any lost revenue due to contaminated ash issues, the EPA observes that almost all of an EGU's revenues are derived from electricity sales, with ash sales representing a very minor income stream at risk to demand forces within the downstream market. Avoided disposal costs are often more significant than any CCR revenues, and if the fly ash can be repurposed for a less valuable purpose, the financial impact to the facility would still be small. Finally, and in any case, the EPA's modeling indicates that the majority of DSI installations will likely be on smaller units because many larger units are already scrubbed for SO_2 control and have no need for DSI. For further discussion on IPM modeling assumptions, see the IPM documentation. Also see the preamble for the final rule for additional discussion of DSI.

As for activated carbon contamination issues, proper location of the injection point will prevent contaminating salable by-products; note an additional PM capture device may be required for collecting Hg-laden activated carbon downstream. An SCR with WFGD configuration burning fuels with sufficient halogen content will oxidize Hg in the SCR followed by capture in the downstream WFGD thereby eliminating the need for ACI. The dissolved water-soluble Hg species is easily separated in the gypsum dewatering/washing process

Comment 6: Commenters 17868 and 17911 express concern that coal ash may be designated as hazardous waste under RCRA (Subtitle C), causing state and municipal governments to feel compelled to remove and remediate the coal ash fill from under buildings, at landfill, and under highways. These costs are not considered in the estimated cost for the proposed rule. The commenters estimate coal ash disposal costs as hazardous waste to range from 5% to 24% of a municipal government's revenues. Commenter 17408 expresses concern about increasingly toxic fly ash as a result of using carbon injection to comply with the rule.

Response to Comment 6: Federal statute limits MATS to stationary source emissions (see the preamble for the final rule for applicability). As for contaminated ash, a station's owner may install a secondary particulate capture device dedicated to removal of DSI absorbents or activated carbon downstream of existing PM equipment. Issues regarding CCR remediation from prior utilization or disposal are not within the scope of the MATS rule.

2. Dry sorbent injection.

Comment 7: Multiple commenters (17623, 17765, 17770, 17775, 17781, 17840, 18033, 18023) explain that the estimated compliance cost and retirement rate is likely to be low because the assumption that DSI and a baghouse will enable a bituminous coal burning source to meet the HCl limit which may not be realistic. Wet scrubbers are likely to be necessary and will increase compliance costs and the number of plants to retire since they cannot afford compliance. Some commenters (17765, 18033, 19114) state that the EPA needs to examine what portion of the estimated 56 GW of the existing fleet expected to install DSI instead of scrubbers may realistically do so to more accurately estimate costs because the commenter believes that cost of complying with just the acid gas standard could easily be almost $12 billion annually. Commenter 17770 reports findings from a testing program that shows DSI is able to control acid gas HAP only from units burning low rank western coals. The commenter asks the EPA to reconsider its projections regarding DSI to control acid gases based on data available from DOE-NETL and others. Commenter 17775 refers to modeling that shows the proposed rule will result in tens of billions of additional dollars for compliance due to standards for non-Hg HAPS that will require more control than can be achieved with DSI alone and no measurable health benefits. Commenter 19114 states that few coal-fired units use DSI for any purpose and none have been identified that employ DSI for HCl control. Given the lack of practical experience in the industry, the commenter believes the EPA should revisit the application and performance attributes of the technology or risk understating the potential costs and number of induced unit retirements.

Response to Comment 7: DSI is commercially proven for acid gas control as vouched by Babcock & Wilcox Company, one of the largest suppliers of air emission control systems in the world. According to B&W (http://www.babcock.com/library/pdf/ps-451.pdf):

> "Dry sorbent injection (DSI) for acid gas control is not a new technology. DSI systems have been in service for more than 20 years as an effective tool to reduce acid gas levels. SO2 and HCl emissions are typically controlled together. In some industrial applications, HCl may need to be controlled

separately. Current and impending legislation are the drivers in determining the required emissions levels. DSI is a cost-effective solution to control these emissions."

As discussed in the preamble, the EPA has used very conservative assumptions in modeling the projected use of DSI technology. See the preamble for the final rule for a more detailed discussion of DSI.

Comment 8: Commenter 17758 agrees that DSI can be used for compliance at many units cost effectively, but strongly disagrees with the assumption underlying the proposal that DSI and dry scrubbers will be the compliance method for acid gas control at all units because DSI has not been widely demonstrated in practice. The commenter notes that out of 131 units that define the HCl floor, only 15 units currently use DSI, and only five of those units use DSI without FGD.

Response to Comment 8: The EPA does not believe that DSI and dry scrubbers will be the only compliance options for control of acid gases, and utilities will choose compliance pathways based on a variety of considerations and available technologies. DSI is a commercially available technology and the EPA believes it will play an important role for achieving compliance. See preamble for further discussion on DSI and other compliance options.

Comment 9: Commenter 16469 explains that DSI is applicable to smaller units burning low-sulfur subbituminous coal. The commenter states that operational performance systems using sodium bicarbonate indicate SO_2 removal rates in the range of 20-60%, which is below the >90% SO_2 removal typically associated with wet scrubbers. The commenter includes a table showing removal rates for HCl and SO_2 at increasing bicarbonate flow rates in the range of 75-95% for HCl and 20-60% for SO_2. The commenter reports that analysts believe that DSI is likely to be used by smaller units, with larger unit installing scrubbers. The commenter also believes that additional controls may be needed to address future regulations which could entail retrofit scrubbers and SCRs to achieve SO_2 and NO_X control. Commenter 19114, on the other hand, states that they have installed over 10,000 MW of coal-fired units and has experience with the operation of DSI and sees the quantities of Trona required for the needed removal efficiencies to be too expensive and logistically cumbersome to maintain for smaller units.

Response to Comment 9: See the preamble for the final rule for a discussion of DSI.

Comment 10: Commenters 17620 and 17648 report that the ACI and DSI technology required to comply with the proposed rule have existed for many years. Commenter 17620 states that these technologies require little capital for construction and normally involve installation schedules of less than 12 and 24 months, respectively while FGD and SCR technologies require longer schedules. The commenter states that industry has demonstrated its ability to add the controls by the deadline, pointing out that applicable compliance was achieved following past regulations being passed. The commenter mentions the 26 GW of new SCR controls that came on line in 2003 to meet the NO_X SIP, while approximately 70 GW of SCR and 10 GW of FGD capacity were installed in 2000-2004. The commenter cites IPM modeling estimates that show 83 GW of new scrubbing and 65 GW of DSI added to the existing 145 GW of capacity that has scrubbing. Also, the estimates add 98 GW of ACI and 26 GW of new SCR for NO_X control. Commenter 17648 confirms that ACI is a feasible control technology for Hg emissions, regardless of the control technologies presently used to control for PM, SO_2 or NO_X and gives examples of how this can be done. The commenter also points out that regulation often drives development of cheaper, more efficient controls. The commenter confirms that technologies exist to achieve the reductions called for by the proposed rule. The commenter believes that sources can reasonably expect to be able to alter source fuels or select and install suitable controls to achieve the proposed emissions limits.

Response to Comment 10: The EPA thanks the commenter for the information provided in support of the proposed rule.

Comment 11: Commenter 17648 disagrees with criticism that the EPA's analysis underestimates the number of units that will need to install wet or dry FGD controls to meet the proposed acid gas limits. The commenter says that DSI is a mature technology that is well suited for units that burn fuels with lower or mid-level sulfur contents and is among the viable options for a number of sources to achieve the proposed HCl limits. The commenter points out that 73% of the sources with HCl emission data in the ICR database already achieve the proposed HCl limit and several of them do so using DSI. The commenter goes on to list coal-fired units that control SO_2 using DSI.

Response to Comment 11: The EPA thanks the commenter for the information provided in support of the proposed rule.

Comment 12: Commenter 17702 acknowledges that they have compliance options to meet the proposed requirements, such as adding carbon injection or switching to a wet scrubber. However, the commenter feels this will add additional costs and defeat the environmental objectives that led to the selection of their air pollution control system, such as conserving water with a dry scrubber as opposed to a wet scrubber and finding a way to use the calcium byproducts. However, the proposed emission limits will require ACI, which will interfere with the ability to sell the byproduct.

Response to Comment 12: Although wet scrubbers (WFGD) use considerable amounts of water, approximately 90 weight percent of the water can be recovered in a gypsum slurry dewatering process and returned to the system. Water used for quenching incoming flue gas to the wet scrubber, can be minimized by lowering flue gas temperatures to the minimum permitted by design.

As noted above, for activated carbon contamination issues, proper location of the injection point will prevent contaminating salable by-products; note an additional PM capture device may be required for collecting Hg-laden activated carbon downstream. An SCR with WFGD configuration burning fuels with sufficient halogen content will oxidize Hg in the SCR followed by capture in the downstream WFGD thereby eliminating the need for ACI. The dissolved water-soluble Hg species is easily separated in the gypsum dewatering/washing process.

Current scrubbing technology captures MATS acid gases with superior effectiveness relative to SO_2;[20] as a result, the EPA does not anticipate scrubber retrofits for MATS compliance on units equipped with a wet or dry scrubber.[21] The EPA expects that a dry scrubber with a fabric filter is a control configuration where no additional controls may be required in some cases.[22] Where additional controls are needed, the EPA believes that units with dry scrubbers with fabric filters may choose ACI, but they may also find other approaches effective. In many cases, especially bituminous coal units, high co-

[20] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" March 31, 2011, pp. 11-12, 21
[21] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS Corporation, April 5, 2011; p.7, Table 2-1
[22] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" March 31, 2011, p. 20

benefit capture occurs without the need for ACI. For low rank coals, capture can be enhanced with bromide addition. Experience has shown that addition of oxidizing agents (i.e., bromide) and/or the use of sorbents designed to mitigate or avoid the adverse effects of activated carbon on fly ash, including mineral-based sorbents, are available and effective.[23] As a result, the EPA believes that facilities with dry scrubbers are especially well suited to comply with the rule at relatively low expense.

Comment 13: Commenters 17736 and 19114 question the effectiveness of DSI to control acid gas emissions from coal-based EGUs and point out that no such units have been identified as employing DSI for HCl control. The commenters have experience installing Trona injection systems on coal-fired units and understand the shortcomings of DSI injection. As such, the commenters find SO_2 removal by DSI to be too costly and cumbersome to be practically applied. Specifically, the commenters find the nozzle pluggage and antagonistic effects on ESPs would make achieving HCl and PM limits difficult over a 30-day period. Commenter 19114 questions the EPA's "Documentation Supplement for EPA Base Case v4.10_PTox – Updates for Proposed Toxics Rule" which quotes a DSI test done by a company specializing in this technology using Trona and other sodium-based sorbents to remove SO_X and other acid gases and will substantially benefit from regulation requiring DSI technology. The commenter points out that the document referenced by the EPA is a simple slide presentation about a single test, and lacks technical specifics that allow the data to be extrapolated to such a broad range of units as those in the utility industry. The commenter expresses concern that the EPA allows for the use of DSI in conjunction with existing ESP systems without regard to size or performance, as this is not supported by available data. The commenter also questions the assumed SO_2 removal of 50-70% with DSI, as it is not supported by the indicated data. The commenter also worries that there could be potential cost premiums for affected units if they are all forced to rely on a single vendor for the required technology and points out that the testing reports used by the EPA do not evaluate potential operations concerns. The commenter also states that the costs associated with maintaining a DSI system due to pluggage and antagonistic effects on ESPs would make achieving both the HCl and PM limits very difficult to achieve over a 30-day operating period. The commenter calls on the EPA to expand the quantity and quality of their review.

Response to Comment 13: The EPA has determined that DSI is an effective acid gas control technology since MATS acid gas removal exceeds SO_2 capture rates with this technology.[24] Despite comments claiming DSI as too costly or cumbersome, this control technology occupies less space and requires substantially less capital investment than a unit employing a wet or dry scrubber.[25] However, a DSI system's operating costs tend to exceed a wet or dry scrubber for high sulfur fuels. As a result, the EPA's IPM modeling limited the DSI retrofit option to units combusting fuel less than 2.0 lb SO_2/MMBtu. Pluggage issues result from poorly designed systems for powdered solids conveyance. A variety of causes can lead to blockage; for example, poorly designed piping systems, inappropriate storage practices, incorrect system operation, plus others. Similar problems arose and were solved in analogous industries of food processing (wheat flour, powdered sugar), concrete (dry Portland cement), and pharmaceuticals etc. regarding dry powder material transfer. The EPA has noted that there are commercially available solutions to address these issues.[26] Pluggage problems at a particular facility do

---

[23] Hizny, W., Magno, G., Yang, X., "BASF Mercury Sorbent ZX™ for Control of Coal-fired Power Plant Hg Emissions," Paper # 176, Power Plant Air Pollutant Control "MEGA" Symposium, August 30 – September 2, 2010, Baltimore, MD
[24] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" March 31, 2011, p. 22
[25] ibid, p. 13
[26] UCC web site; DSI FAQ #3 Plugging Issues. Web site: http://unitedconveyor.com/dsi.aspx

not disqualify DSI as a commercially available control technology. With regard to impact on ESP performance, DSI using sodium-based reagents has been shown to improve ESP performance; this has been a consistent phenomenon that is the result of the beneficial impact of sodium sorbent on fly ash resistivity. Also see the preamble for the final rule for a further discussion of DSI.

Comment 14: Commenters 17758 and 18033 discusses the EPA's acknowledgement that if DSI does not achieve the required HCl reductions, utilities will need dry or wet scrubbers to achieve compliance, which the commenters believe will prompt more unit retirements. Commenter 17758 also mentions that the cost for DSI varies from $4/MWh to $15/MWh and there are few suppliers of DSI technology, especially the Trona. Commenters 17758 and 17775 cite difficulties with the Trona supply with estimates of costs to deliver Trona to the eastern U.S. as high as $200/ton due to logistical difficulties. For instance, the special rail cars needed, the limited plant storage silo sizes and short shelf-life of the product al contribute to making increased Trona supply difficult to achieve. Finally, the commenters note that units using DSI or ACI often need PM control downstream, such as a baghouse or ESP and a baghouse typically takes 36 months to install and costs $200/KW. Overall, the commenters question the cost-effectiveness of DSI, quoting BPC as saying that, "…capital costs for an alternative, dry sorbent injection are significantly lower. On a levelized cost basis, however, the difference is far less significant…" Commenter 17781 agrees with this conclusion and says that while DSI can be economic with low sulfur fuels and/or operated over short time periods, many EGUs will need to install spray dryer adsorbers (SDAs) in lieu of using DSI, which means longer lead times for procurement and installation of at least a year.

Response to Comment 14: The EPA disagrees with the commenters and does not expect that scrubbers are necessary solely for acid gas control under the MATS rule. The EPA has analyzed the supply of Trona and sodium bicarbonate and determined that it is ample, as soda ash (a product of mined Trona) is already used extensively for other industries (such as glass manufacturing, detergents, etc.) that need a reliable supply. Trona is a very reactive substance, and relatively small amounts are required to control HCl. Trona DSI has also been shown to improve ESP performance, so that a fabric filter is generally not necessary unless otherwise needed for PM control. As discussed in the preamble, recent testing shows that trona DSI control of HCl with an ESP is very nearly as effective as with a FF. Facility owners may choose to install scrubbers for control of acid gas; however, this does not change the EPA's determination that other technologies are available and can be used to comply with the rule at reasonable cost and in the time frame of the rule. Also see the preamble for the final rule for a further discussion of DSI.

Comment 15: Commenters 17765 and 18033 report that private sector estimates of retirements are higher than the EPA's estimates because of the unproven effectiveness of DSI, the lack of reliability of the reagent supply chain, the lack of industry experience with the technology and the potential impact of dispatch. These concerns lead to retirement estimates of 50 to 100 GW. Commenter 17765 believes that without further testing to show that DSI technology can be relied on for compliance, few utilities will choose it. The commenter finds the EPA's compliance timeline makes it difficult for utilities to obtain information necessary to make decisions about control technologies or unit retirement. The commenter also points out that many of the 56 GW capacity units the EPA estimated would choose DSI will not have that option due to overlapping CAA rules.

Response to Comment 15: The EPA disagrees with the commenters' assumptions. There have been numerous private sector studies that examine retirements due to several EPA rules that have been proposed or finalized over the past 2 years. Many of these studies were based upon assumptions of what a rule might require prior to its proposal or finalization, and the assumed requirements were generally more stringent than the actual requirements proved to be. Although the EPA's modeling for MATS predicts that some units will choose DSI, the EPA recognizes that some of these units may not actually do so, for a variety of reasons that may involve owner preferences and site specific circumstances. Also see the preamble for the final rule for a further discussion of DSI.

Comment 16: Commenters 17775 and 18037 discuss various adverse consequences of DSI use, pointing out that it can hinder compliance with Hg and PM limits as the injected reagent adversely affects baghouses, and requires that three times the normal amount of ACI be used to achieve the same level of Hg control, as well as leading to the mission of a visible brown plume from the high sodium content.

Response to Comment 16: The EPA is aware that there is some data suggesting DSI can adversely impact ACI performance. In particular, the Presque Isle tests where this was observed were for SO_2 control, and the Trona treatment rate for those tests was therefore higher than would be necessary for control of HCl for PRB fuel. PRB fuel typically has low HCl emissions and likely will not need additional controls for HCl in most cases. On the other hand, DSI can improve ACI performance for bituminous units because of the reduction in SO_3, which interferes with ACI capture of Hg. DSI using sodium compounds (Trona, etc.) has actually been shown to improve ESP performance. Therefore, little or no adverse impact is expected with regard to PM. Improper DSI operation can adversely affects PM and Hg control. Insufficient bag house capacity or excessive sorbent injection rate can adversely affect PM control performance.[27] An improper operating temperature reduces activated carbon's ability to capture Hg[28] while high concentrations of SO_3 compete with mercury for capture.[29] DSI systems failing to remove sufficient SO_3 negatively impact ACI system performance.[30] Hg speciation exiting the furnace significantly impacts controls selection and performance, with multiple factors affecting speciation (e.g., fuel constituents, halogen presence, installed emissions controls, and temperature).[31,32] ESP performance typically improves with sodium based sorbents; on the other hand, a calcium based species tends to negatively impact operation.[33] The brown plume phenomenon apparently can occur under conditions of high treatment rates on units that do not have NO_X controls,[34] but this is not anticipated for HCl control due to the lower treatment rate needed for HCl removal. Formation of a brown plume appears to be an event too infrequent to disqualify DSI as a control scheme within the MATS. Represented by the Presque Isle tests, one system produced a brown plume; on the other hand,

---

[27] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS Corporation, April 5, 2011; p.A-10

[28] Ibid., p.A-8

[29] Ibid.

[30] Ibid.

[31] Solvay Chemicals publication "Mercury (Hg)"

[32] Tutorial: Mercury Chemistry in Boilers and Mercury Control Technology (Part 1) by C Senior, Reaction Engineering Intl., 30th International Technical Conference on Coal Utilization & Fuel Systems; April 17-21, 2005

[33] UCC web site; DSI FAQ #1 ESP Performance. Web site: http://unitedconveyor.com/dsi.aspx

[34] Sjostrom, S.,Senior, C., Durham, M., Bustard, J., "INTEGRATED MACT COMPLIANCE PLANNING," http://www.adaes.com/PDFs/presentations/AQVIII-Integrated%20MACT%20planning.pdf

over 30 other DSI systems did not generate a brown plume.[35] Also see the preamble for the final rule for a further discussion of DSI.

Comment 17: Commenter 17775 explains that the assumption that an adequate supply of dry sorbents will be available is not a good one. The commenter explains that sorbent production will need to increase by 10 to 20 times in order to meet the EPA's projected DSI demand. This is a problem, the commenter explains, because the industry is not going to spend hundreds of millions of dollars on plant expansions without a secure market, but until the utilities decide to install DSI, they will not know what the demand will be. Once a commitment is made, it will take more than 18 months to increase sorbent production to necessary levels to supply all the projected new DSI units.

Response to Comment 17: Multiple comments submitted claim insufficient absorbent (or sorbent) production capability exists to serve the DSI market. The agency researched this issue and determined that DSI utilizes the following absorbent materials for pollution control: Trona, sodium bicarbonate, sodium carbonate (common name: soda ash), calcium carbonate, and calcium bicarbonate - sodium based chemicals are favored over calcium based materials due to economics. Trona is mined in Wyoming as a naturally occurring ore by four companies with mining operations extracting 16.5 million tons in 2010.[36] Production peaked at 18.1 million tons in 2006.[37] In 2010, end consumers received 176,000 tons of Trona via direct shipment[38] while the balance was converted into soda ash and related chemicals. Note that soda ash is an acceptable absorbent for DSI pollution control. Exports claimed one-half of the 10 million tons of soda ash produced in 2010.[39] Currently, the industry (ANSAC) alleges unfair foreign practices negatively impacting domestic exports.[40] Considering the excess Trona mining capacity, the fact that nearly 50 percent of Trona-based derived soda ash is exported, and the fact that alleged foreign competition practices negatively impact exports - the agency concludes that Trona supply is not an issue.

The EPA disagrees with commenter's estimate and has concluded that current U.S. Trona production may already have adequate surplus capacity to meet projected DSI demand. See the preamble for the final rule for a further discussion of DSI.

Comment 18: Commenter 17790 explains that the EPA's analysis of emission reduction technologies required by their facilities to comply with the proposed rule is erroneous because it assumes they will install fabric filters on all coal-fired units. However, the commenter's analysis showed that DSI is only economical on units which are able to achieve compliance-level reductions of HCl using ESPs, and spending additional money on fabric filters is not economical for them.

Response to Comment 18: The EPA's IPM modeling for the MATS final rule now takes into consideration that there are less costly options than FF for PM compliance, particularly the upgrading of

---

[35] "Comparison of Sodium Bicarbonate and Trona for SO2 Mitigation at a Coal-Fired Plant" by Kong & Vysoky (Solvay Chemicals) Electric Power 2009 presentation, May 12-14, 2009.
ref: http://www.solvair.us/static/wma/pdf/1/5/8/4/0/SO2_Mitigation-Electric_Power_2009.pdf
[36] http://www.wma-minelife.com/trona/TronaPage2/trona_production.htm
[37] ibid
[38] http://www.onrr.gov/ONRRWebStats/StateAndOffshoreRegions.aspx?state=WY&yeartype=FY&year=2010&dateType=AY
[39] http://minerals.er.usgs.gov/minerals/pubs/commodity/soda_ash/mcs-2011-sodaa.pdf
[40] http://www.ansac.com/news/2011/06/01/

existing ESPs. Please see the documentation for IPMv4.10_MATS. In addition, Trona DSI has been shown to improve ESP performance, a benefit that the EPA's IPM analysis has conservatively has not incorporated. For these reasons, many units that were previously modeled as installing a FF may find that only the installation of DSI upstream of the existing ESP may be needed for MATS compliance. Also see the preamble for the final rule for a further discussion of DSI.

Comment 19: Commenter 18033 requests that the EPA address integrated planning after the proposed NSPS for GHS from EGUs are issued to create a cumulative cost analysis. The commenter states that neither a utility or public utility commission would permit the investment in DSI technology and sorbent storage facilities if a scrubber would be needed a few years later. The commenter went on to explain that not every coal type within the projected 56 GW expected to install DSI will be able to meet the compliance limits using that technology. The commenter refers to Sargent & Lundy report which states, "[t]he DSI technology should not be applied to fuels with a sulfur content of greater than 2 lb SO_2/MMBtu." (Footnote 57 to EPA-HQ-OAR-2009-0234-18033-A2 gives NMA revised cost estimates for DSI.)

Response to Comment 19: Issues regarding a NSPS for GHG from EGUs are not within the scope of the MATS rule, although the EPA does intend to seek to coordinate requirements under today's rules with those of the pending NSPS for GHG emissions. Also see the preamble for the final rule for a further discussion of DSI.

Comment 20: Commenter 18421 states that DSI can be used with a variety of sorbents to allow an approach tailored to the source and unit characteristics. The commenter quotes NESCAUM "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants," March 31, 2011, as estimating capital costs and storage silo costs for DSI at around $20/kW. The report also cites approximately 90 coal units currently using DSI, showing that it is effective at reduction HCl by more than 99% and works efficiently with a downstream fabric filter or ESP. The commenter also quotes SOLV Air, a Trona distributor, as refuting claims that Trona is likely to be unavailable by saying "hundreds of years of reserves of Trona are available." Commenter 17621 agrees with the idea of various options for sorbents used with DSI technology and explains the various pros and cons of some options. The commenter reports on a Trona injection test that resulted in a visible brown plume and degradation of Hg removal by ACI. The commenter explains that while hydrated lime injection would remove SO_3 without the adverse impacts of Trona, it is unknown if the hydrated lime could meet the proposed limit at any injection rate or if it would increase pressure drop across a baghouse to unacceptable levels. The commenter also mentions the practice of grinding sodium sorbent before introducing it to the feed system, then injecting the finer material upstream of the air preheater. This practice is believed to increase mixing and residence-time, providing greater SO_X and HCl reduction. However, the method can also lead to air preheater pluggage in some cases. The commenter describes a field test program in which Trona or sodium bicarbonate was used to achieve high HCl and SO_2 removal rates without pluggage problems. The commenter explains that the site has an atypical system including both hot- and cold-side ESP, and sorbent was injected upstream of the hot-side ESP which may have minimized pluggage and plumes. This commenter believes that further investigations are needed of DSI over a range of power plant designs, coal types and air pollution controls to fully evaluate HCl and SO_2 removal performance and impacts on balance-of-plant operations.

Response to Comment 20: The EPA thanks the commenter for the information provided in support of the proposed rule.

Comment 21: Commenter 18424 considers the EPA estimates for control technologies to be suspect since they may not be appropriate for use by many power plants, depending on the coal burned and the impacts DSI will have on PM and Hg emissions. The commenter questions the method of developing emission rules for each pollutant independently without considering how one control device may impact the control of other pollutants.

Response to Comment 21: The EPA disagrees with commenter. The EPA evaluated the effects of DSI on different fuels and considered the effects on Hg and PM emissions. See the documentation for IPMv4.10_MATS, and the preamble for the final rule for a discussion of DSI. It is important to note that the EPA established emission standards based on the best-performing sources in each subcategory for the different emitted HAP. The EPA is not specifying the use of a particular control device, leaving it to the discretion of the source owner or operator to select controls that will meet the applicable standards considering the characteristics of the particular source.

Comment 22: Commenter 18023 disagrees with the assumption that 56 GW of coal plants will not need a FGD system because DSI will suffice at a lower cost and shorter timeline for installation. The commenter states that even if DSI can achieve the HCl removal levels required to comply, it would not do so under all operating conditions. The commenter states that the EPA's model predicted that several of the commenter's power plants would not achieve continuous compliance with the proposed acid gas limit using DSI. (Commenter includes Figure 6 showing necessary technology to achieve compliance with proposed HCl limit.) Therefore, the commenter believes the costs and timeline on which the proposed rule is based are erroneously low. The commenter also disagrees with the assumption that wet scrubbers will not be widely required to meet the proposed emission limits since dry scrubbers are more appropriate for smaller units with lower sulfur fuels, which does not describe all units. The use of wet scrubbers will also drive up compliance costs so the commenter asks that the EPA update cost assumptions to account for these requirements.

Response to Comment 22: The EPA disagrees with the commenter. The EPA has determined that wet scrubbers, while beneficial for acid gas control, are not necessary for compliance with the MATS rule. Also see the preamble for the final rule for a further discussion of DSI.

Comment 23: Commenter 17775 states that the proposed rule will require large-scale installation of new control technologies to meet the Hg, HCl and total PM limits. The commenter restates the EPA estimates that the proposed standards will require the installation of 93 GW of ACI, 56 GW of DSI, 26 GW of wet FGDs and dry FGDs, 166 GW of FF and 5 GW of SCR, and that this $46 billion (in 2007 dollars) of control equipment can be installed in 3 years. The commenter considers the EPA's estimate to be unreasonable because it is based on incorrect assumptions about the efficacy of DSI.

Response to Comment 23: See the preamble for the final rule for a discussion of the efficacy of DSI. Also see the RIA for projected controls retrofits and costs as updated in EPAs analysis for the MATS final rule.

Comment 24: Commenter 17775 questions the EPA's conclusions about the effectiveness of DSI since they are based on limited information and incomplete analyses. The commenter points to ICR data from plants using DSI systems to see that only 11 of the 28 units using DSI do so to control SO_2 and only two of those 11 units report ICR emissions data that show compliance with the proposed existing source HCl limit. In fact, those two cases the units burn low chloride fuel and do not need to install DSI to meet the HCl limit. Therefore, the commenter states that there is no example of an EGU system that complies with the HCl limit as a result of having a DSI system. The commenter also explains that the Sargent &

Lundy report cited by the EPA to support its views on DSI are lacking information on how DSI may affect PM or Hg emissions. Also, the commenter says that the Solvay Chemicals case study to predict Trona feed rates for HCl and SO_2 removal was for sodium bicarbonate injection, not Trona, making the feed rates inaccurate. In addition, the commenter points out that the flue gas make-up in the case study was not representative of low sulfur coals.

Response to Comment 24: The EPA disagrees with commenter's conclusions. Also see the preamble for the final rule for a further discussion of DSI.

Comment 25: Commenter 18963 notes that there have been no commercially demonstrated applications of DSI for the control of HCl from coal refuse-fired CFB units. Further, even to the extent that it is technologically feasible to use sorbent injection to control HCl from coal refuse-fired CFB units, the use of different sorbents for this purpose may affect the quality of the ash residue. Such ash is currently used in the environmentally-beneficial step of reclaiming lands and protecting and enhancing streams damaged by acid mine drainage.

Response to Comment 25: See the preamble for the final rule for a further discussion of DSI.

Comment 26: Commenter 16849 states that even under revised averaging periods, Trona and DSI are not a viable option for Empire, as is incorrectly stated by the EPA ("IPM Parsed Results - Policy Case," Unplanned DSI Installations by 2015 includes Asbury: 2076_B_1).

Response to Comment 26: The EPA believes that DSI has the potential to be a useful and cost-effective control technology option for many units. We also understand that it is not an appropriate option for all facilities. Overall the EPA believes that the technology is most applicable for units burning lower-sulfur content coal (including, potentially, low-sulfur bituminous coal).

3. Electrostatic precipitators.

Comment 27: Commenter 17622 explains that ESPs are the primary particulate collection equipment for many utility units and are designed to have sufficient Specific Collecting Area (SCA) to meet the proposed total PM emission limits. The commenter considers it to be in the best interest of the industry to retain existing plant assets as much as possible while complying with the proposed rules. The commenter explains that ESPs can be upgraded by improved maintenance/repair, parts replacement, etc., or rebuilding to increase SCA. However, the commenter points out that the potential for upgrading existing ESP installations to meet the proposed limits depends on the age and design of the existing equipment. Not all equipment was designed to achieve 0.03 lb/MMBtu to begin with, and may not be able to comply with the proposed emission limits even after being rebuilt. Some equipment may require expanded collecting area, but not have the space to accomplish this. Another solution, where space is available is to add a polishing fabric filter after the ESP. Also, an existing ESP may be converted to a pulse jet fabric filter. The addition of a fabric filter or conversion from an ESP to a fabric filter would allow better utilization of Trona or lime for HCl and SO_3 control and allow the potential to include other reagents for Hg control. There is an impact on the ID fans and structure to convert to a fabric filter, but much of the existing support structure and ducts/casings could be used. The final solution suggested by the commenter is the addition of a wet ESP to an existing wet FGD to capture filterable and condensable particulate. The commenter offers the Dallman and HL Spurlock plants in the ICR PM database as examples of this approach and explains that this alternative has the advantage of using existing air pollution control equipment with low increase in pressure drop.

Response to Comment 27: The EPA thanks the submitter for the information provided in support of the proposed standard MATS and notes that this information corroborates the EPA's views about the availability of multiple compliance options for many affected sources.

4. Timeline.

Comment 28: Several commenters (17627, 17655, 17911, 19114) express concern over the compliance timeline of the proposed rule. In particular, the number of regulations focusing on the same pollutants in the same timeline is a concern because of the pressure likely to be placed on control equipment suppliers and skilled labor for installation will not allow all the units to acquire the needed equipment in the given time period. Commenter 17655 reports that an SCR originally estimated to cost $33 million actually cost them $61 million entirely due to the fact that all the CAIR-affected units were competing for the same design, material and labor pools during a compressed construction schedule to comply. The commenter expects the same thing to happen to a greater extent in response to the proposed rule.

Response to Comment 28: Commenters recalling price escalation during CAIR's implementation phase understandably convey concerns regarding the EPA's cost estimating; however, the present economic situation does not reflect current national or global conditions. During CAIR implementation, high global demand for construction commodities (especially from China) attributed to cost escalation. Presently, commodity prices are relaxed from their peak due to lower global economic activity. Considering the current economy, the EPA anticipates the first wave of retrofit controls orders to be less costly than recent historical prices since suppliers will compete for work to utilize idle resources. As an indicator, demand for power plant construction labor declined from its peak in 2008.[41] For example, Colorado Springs Utility plans to retrofit its 254 MW Martin Drake unit with a FGD for $113 million with projected construction completed by 2014.[42,43] Timeline compliance date attainment and available resources are addressed in the preamble for the final rule and Response to Comments section 5C01 "Compliance Dates."

Comment 29: Commenter 17627 explains that facilities must start now to assemble justification of supplier and construction constraints to receive an extension from state regulatory agencies. However, the commenter points out that this step is unreasonable before the final requirements are known and compliance plans are designed, and permitting authorities generally do not allow any construction preparation until permits are granted.

Response to Comment 29: The agency believes that the MATS proposal offered sufficient regulatory detail to inform prudent retrofit planning activities, some of which at least could be commenced without further delay. To cite an example, a station owner ordered two wet scrubbers (465 MW and 515 MW

---

[41] Staudt, J., E., Andover Technology Partners, "Labor Availability for the Installation of Air Pollution Control Systems at Coal-Fired Power Plants," www.AndoverTechnology.com, viewed November 6, 2011

[42] http://www.power-eng.com/articles/2011/10/coal-fired-power-plant-to-receive-emissions-control-system.html

[43] Colorado Springs Independent; Oct 4, 2011 "Update: Utility Strikes Deal on Emissions Control" by Pam Zubeck
Ref: http://www.csindy.com/IndyBlog/archives/2011/10/04/utilities-strikes-deal-on-emissions-control

units) with scheduled start dates of 2013 and 2015.[44] Timeline compliance and resource availability are discussed in the preamble for the final rule and Response to Comments section 5C01 "Compliance Dates."

Comment 30: Commenter 17758 states that compliance for many utilities, especially those burning eastern bituminous coals, may have to install a wet FGD which presents challenges in cost and installation time. The commenter estimates wet FGD will cost approximately $350/KW more than DSI, and the timeline for wet FGD installation will be around 60 months as opposed to 9-18 for DSI. This makes the EPA's assumptions about both the cost estimates and ability to comply within 3 years incorrect, the commenter believes.

Response to Comment 30: The EPA disagrees with comments warning wet scrubbers are necessary for units burning eastern bituminous coal. The EPA examined this issue and determined DSI adequately suffices for units burning low sulfur eastern bituminous coal. The EPA's IPM analysis for MATS limits DSI retrofit controls for compliance to fuels containing less than 2 lbm SO_2/MMBtu. Timeline, feasibility, and emissions control capability issues are discussed in the preamble for the final rule, and Response to Comments section 5C01 "Compliance Dates."

Comment 31: Commenters 17775 and 17904 discuss the many steps involved in adding controls to coal-fired EGUs, such as initial design, development of project specifications, procurement, identification of bidders, solicitation, review of bids and contract negotiations, permitting, landfill issues, obtaining financing, final design, mobilization of workforce, construction, process tie-ins and startup testing. Commenter 17775 includes a memo (J. Edward Cichanowicz, "Feasibility of Retrofitting Fabric Filter Particulate Matter Control Technology to the Electric Generating Unit Inventory as Projected by EPA" (July 2011) Attachement 12 of EPA-HQ-OAR-2009-0234-17775) showing estimates of 48 months to install a single scrubber for a large unit, 50 months for a single scrubber at a small unit, 51 months for installation of two scrubbers and 54 months to install three or more scrubbers at a single facility. The memo also estimates that not all existing EGUs that need a new fabric filter will be able to meet a 3-year compliance schedule, and even if given 4 years to comply, only 54% would be able to comply. The commenter also explains that time needed to obtain financing can vary greatly, with some regulated utilities needing to obtain approvals from their State PUCs to recover the costs, and some rural cooperatives needing to access the private market for funding. Commenter 17904 refers to *Davis Cnty. Solid Waste Mgmt. v. EPA*, 101 F.3d 1395, 1400 (D.C. Cir. 1996) wording that states the EPA's MACT floor would "impose significant retrofitting costs that [are] unreasonable given the limited additional pollution control that stricter standards would achieve." The commenter expresses concern over the high costs and short timeline for the necessary control retrofits.

Response to Comment 31: For discussion on the issues mentioned above, see the preamble for the final rule and Response to Comments section 5C01 "Compliance Dates."

Comment 32: Commenter 18039 questions the suggestion that existing units be allowed to run for an additional year while a replacement is constructed, without being subject to MACT standards for that year. The commenter agrees that this is a reasonable scenario for facilities that will use that year to construct a replacement unit with significant long-term emission reductions. However, the commenter is

[44] B&W press release June 29, 2011; "B&W to Design and Supply $54 Million Emissions Control System for Indiana Power Plant" ref: web site: http://www.babcock.com/news_and_events/2011/20110629a.html

concerned that a facility in the process of building replacement power may decide to operate a high-emitting unit for an additional year, specifically due to the extension. The commenter therefore objects to the extension for fear a large amount of pollutants will result. The commenter also asks that if construction replacement power lasts longer than the 1-year extension, the final rule wording make clear that the older unit is not permitted to avoid MACT compliance beyond that year, even if the replacement is not yet on-line.

Response to Comment 32: Issues regarding compliance dates, extensions, state programs regarding agreements, replacement power construction, etc., are discussed in the preamble for the final rule.

Comment 33: Commenter 18017 states that if the proposed rule and other pending rules require installation of new control equipment costing hundreds of millions of dollars, the potential result could be early closure of their plant because the owners will be required to comply before they know whether the approvals necessary to operate after 2019 can be obtained. The commenters concern is that the EPA may establish final emission limits governing NGS PM emissions that are so stringent that a new PM control device will be required with compliance dates before approvals can realistically be obtained. This would lead to high compliance costs and could jeopardize continued operation of the NGS facility with severe economic impacts on numerous Indian Tribes.

Response to Comment 33: The EPA will work closely with other regulatory authorities to support timely implementation of MATS.

5. One technology per pollutant.

Comment 34: Commenter 17682 considers the EPA estimate of compliance technologies to be suspect because of the proposal of adopting an untested compliance technology to reduce sulfur emissions, and which may impact PM and Hg emissions. The commenter asks that the EPA refrain from developing emission rules for each pollutant independently without considering how one compliance measure may impact the control of other units. The commenter believes this approach leads to cost estimates that do not adequately reflect the cost for other sources of energy that may be required to make up for lost coal-fired generation. The commenter would like to see cost estimates that adequately reflect the ultimate cost increases that individual home owners will need to pay.

Response to Comment 34: The agency reviewed all technologies presented within the proposal for adequacy and commercial availability; moreover, independent publications and trade organizations confirms their capability towards achieving MATS compliance.[45,46,47]

See the preamble to the proposed rule for a discussion of the pollutant-by-pollutant (or HAP-by-HAP) approach for establishing section 112(d) standards.

Average projected cost increases to the rate payer are addressed in the preamble for the final rule.

---

[45] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" March 31, 2011

[46] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS Corporation, April 5, 2011, http://www.supportcleanair.com/resources/studies/file/4-8-11-URSTechnologyReport.pdf

[47] EPA-HQ-OAR-2009-0234-17622

6. Dual liquid-powder sorbent technology.

Comment 35: Commenter 17721 discusses a multi-emission reduction technology called involving a dual liquid-powder sorbent (DLPS), which is particularly effective in removing Hg and other HAP by up to 98.7%, along with SO_2 and NO_X emissions from coal-fired EGUs without adding control equipment into the flue gas stream. The commenter suggests that the effectiveness of the DLPS system for high-sulfur coals makes it a valuable revision to the proposed rule as an available technology for achieving the emissions limits. The commenter also explains that limiting EGU MACT technology to ACI will limit innovation of new technologies and flexibility within the industry and asks that the proposed rule allow for a variety of Hg control systems.

Comment 36: Commenter 17721 considers the proposed rule vague on the point of demonstrating compliance with the Hg emissions limit using a Hg CEMS or a sorbent trap monitor without installing ACI or DSI. The commenter suggests revising the final rule to recognize DLPS technology as an available emission control technology for Hg and other HAP, or at least make it clear in the preamble that the use of a DLPS system instead of, or in combination with other technology, is permitted. The commenter describes three power companies operating eight generating stations that have DLPS technology installed, with results of up to 98.7% Hg reductions. The commenter points out that while it is not yet used as extensively, the DLPS technology is superior to ACI in that it has been shown to improve boiler efficiency in certain conditions, and fly ash from coal treated with DLPS has improved characteristics for reuse, unlike ACI. The commenter describes testing done between 2005 and 2008 and provides the results. (The commenter includes a table of "Full Scale Multi-Pollutant Test Results" in EPA-HQ-OAR-2009-0234-17721-A1.)

Comment 37: Commenter 17721 questions the proposed rule's focus on ACI technology, which works differently from DLPS technology because ACI and DSI involve injecting a sorbent into the flue gas stream upstream of a PM control device to react with acid gases and Hg in the exhaust stream. DLPS technology, the commenter explains, captures Hg, HAP metals, SO_2 and NO_X during combustion to keep them out of the exhaust stream. The commenter points out that DLPS technology offers effective Hg and other HAP metals control for high-sulfur coals without the assistance of additional SO_2 mitigation, making it a reasonable or superior choice compared to the DSI suggested in the proposed rule. The commenter asks that the proposed rule be amended to allow DLPS technology as an available control technology for Hg, HCl and other HAP metals, and allow units equipped with DLPS or DSI to qualify for SO_2 emissions limits as an alternative to the HCl emissions limit.

Comment 38: Commenter 17721 points out that the proposed rule focuses on controlling acid gas emissions in the exhaust stack, while DLPS allows acid gas control in the furnace. The commenter states that DLPS can achieve a 75% reduction in SO_2 emissions before the exhaust reaches the stack, where further emissions reductions could be achieved by a scrubber.

Response to Comments 35 - 38: Multiple comments were received advocating control technologies that were not represented in the EPA's compliance cost analysis of the MATS proposal. The agency notes that control technologies mentioned within the proposal are neither an exhaustive nor an exclusive list; rather, these listings demonstrate proven available technologies for industry sector compliance. The EPA is not selecting, nor precluding, any particular technologies in this rulemaking but is instead allowing each facility to determine its preferred means of compliance with the emission rate standards.

7. Retirements.

Comment 39: Commenter 17731 questions the EPA's view that utilities can easily retire and replace units that are unable to comply with the new emission limits. The commenter considers the option of replacing older units with more efficient units to be risky because the utility may spend the time and money to build new coal-fired units only to find out that the units cannot comply with the stringent new unit emission limits.

Response to Comment 39: This issue is discussed in the preamble for the final rule.

8. Activated carbon injection and alternatives.

Comment 40: Commenter 17734 discusses the use of amended silicates as an environmental and economical way to comply with existing and pending Hg regulations. The commenter describes amended silicates as a "drop-in" alternative that is often superior to partially activated carbon, at a cost competitive with ACI. The commenter explains that the amended silicates are added to the coal combustion gases upstream of PM control equipment to modify Hg into an inert and insoluble state. The commenter states that amended silicates have been designed to be compatible with concrete, allowing for preservation of fly ash value, and passes the EPA leachability tests. The materials have also been developed to avoid the sensitivity to SO_3, so a high rate of Hg capture is maintained in ESPs. The commenter requests that the EPA revise the proposed rule to clearly state that newly developed and commercially-available products besides powder activated carbon can achieve similar or better results under different or similar chemical mechanisms.

Response to Comment 40: Multiple comments were received advocating control technologies that were not represented in the EPA's compliance cost analysis of the MATS proposal. The agency notes that control technologies mentioned within the proposal are neither an exhaustive nor an exclusive list, rather, these listings demonstrate proven available technologies for industry sector compliance. The EPA is not selecting, or precluding, any particular technologies in this rulemaking but is instead allowing each facility to determine its preferred means of compliance with the emission rate standards.

Comment 41: Commenter 17761 reports a dramatic decrease in performance of an ACI system between the years of 2007 and 2009. Given this unexplained decline, the commenter feels it is necessary for the EPA to review the longer term operating performance of control equipment when setting a Hg standard.

Response to Comment 41: Like any air pollution control technology, numerous parameters impact ACI performance with possible causes due to operational changes, equipment degradation, etc. The owner retains responsibility to maintaining their emissions control system and understanding its operation to continuously achieve compliance. ACI is a proven technology for Hg removal with multiple successful installations.[48] This issue is addressed more fully elsewhere in the final rule record.

Comment 42: Commenters 17796 and 17869 indicate that the pollution control technology industry continues to develop new and more cost effective ways to reduce Hg emissions. Commenter 17796 discusses the DOE research on costs of applying activated carbon at various sites. The commenter states that this and other studies show a continued decrease in Hg control costs, with a decrease approaching 50% less for coal-fired EGUs than 1999 baseline estimates. Commenter 17869 quotes the OMB review of ACI technology which states; "the availability and development of ACI technology has shown that

[48] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" March 31, 2011

implementation can be done by a majority of utilities, and the competitive marketplace will continue to reduce the costs for these technologies."

Response to Comment 42: The EPA thanks the commenters for the comments supporting the standard.

Comment 43: Commenters 17813 and 17816 state that the EPA fails to provide complete cost-benefit analysis of beyond-the-floor limit. Commenter 17813 considers this to be an underestimate, in part because more units will be impacted than predicted. The commenter sees the benefit for lignite beyond-the-floor limits to be smaller than the annual benefits predicted for Hg reductions, since there are fewer lignite units and they already comply with the floor limit.

Comment 44: Commenter 17930 states that the EPA failed to provide the proper cost-benefit analysis given the disproportionally high cost of the beyond-the-floor limit compared to any potential gains. According to the commenter, the EPA's estimate of annual cost of implementing the beyond-the-floor limit ($86.7 million) is far greater than the possible benefits of the beyond-the-floor limit. The EPA predicts that the annual benefit of Hg reductions for the entire rule is merely $450,000 to $890,000 by 2016. (See Utility MACT Rule Proposal at 25078. Price estimate at a 7% discount rate. At a 3% discount, the estimated Hg-related benefits are $4.1 to $5.9 million.) The commenter adds that the benefit for the lignite beyond-the-floor limit must be much smaller given the proportion of lignite units compared to other coal- and oil-fired units and since lignite units would already be complying with a floor limit.

Comment 45: Commenter 17904 questions the EPA assumption that a unit equipped with ACI and a fabric filter can achieve the beyond-the-floor standard with no additional cost. The commenter explains that such systems have performance limitations and will not achieve the proposed limit consistently, so alternative and additional controls will need to be considered. The commenter agrees with the dismissal of fuel switching because the variable Hg content of lignite combined with captive mine mouth designs makes the economic impact a marker for establishing actual costs of compliance, which would be prohibitive.

Response to Comments 43 - 45: A quantitative analysis of costs was included in two beyond-the-floor TSDs to illustrate the feasibility of the beyond-the-floor standard for lignite. The EPA established the BTF limit since ample evidence for ACI and fabric filters consistently show high Hg removal rates with a wide range of coals. The BTF limit may be achievable through other means, such as a wet scrubber with bromide addition. In other cases, halogen addition to promote Hg oxidation and capture may be beneficial. ACI is a proven, mature technology for capturing Hg.[49] Comments claiming BTF Hg emission rates for lignite fuels as financially impractical and technically unattainable are unfounded. Commercial products exist to augment[50] Hg capture by ACI - such as Toxecon™ for hot side ESPs, halogen addition for PRB,[51] brominated sorbents for low chlorine fuels.[52] Sources may also blend fuels as part of a compliance approach.

[49] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" p. 19, March 31, 2011

[50] ICAC Report: "Enhancing Mercury Control on Coal-Fired Boilers with SCR, Oxidation Catalyst and FGD"

[51] NESCAUM report, op. cit., p.20

The EPA acknowledges lignite coal may contain increased Hg levels and display greater Hg variability than PRB or bituminous fuels; however, these two aspects do not make BTF emission rates unattainable or financially prohibitive. ACI selectively captures the oxidized form of Hg regardless of fuel source or rank.[53] Yet, the presence of SO_3 interferes with Hg capture and requires removal to avoid high activated carbon injection rates.[54] Furnaces discharging high concentrations of elemental Hg are indicative of low chlorine content fuels (like Texas lignite) and impede ACI performance; under these circumstances, chemical addition to promote oxidization (such as a halogen, as cited earlier) improves performance. Halogens can be inserted: pre-combustion (added to fuel), during combustion (furnace insertion), post combustion (gas stream injection) or through carbon impregnation.[55,56] Meanwhile, adjusting carbon injection rate will compensate for fuel Hg variability. Consequently, the EPA maintains current technology allows BTF Hg capture rates as proposed. See the preamble for the final rule for further discussion.

9. Coal rank/type.

Comment 46: Commenter 17757 explains that coal rank or type has an impact on the design and operation of boilers and associated control equipment. The commenter believes the EPA has not considered the costs of boiler modifications and control technology retrofits in the proposed rule with respect to the coal rank and related factors. The commenter believes these distinctions should be considered and points out that they were factored into the emission rates for the acid rain program and prior Hg proposals issued by the EPA.

Response to Comment 46: EPA notes that the statutory requirements for the Acid Rain Program are distinguishable from standards under CAA section 112. The EPA addresses subcategorization issues elsewhere in the final rule record.

Comment 47: Commenter 17796 states that the cost and degree of Hg reduction depends on coal type and additional costs to upgrade particulate pollution control to accommodate additional particle loading from ACI. The commenter references a DOE study finding that western coal with low chlorine levels emits higher amounts of elemental Hg, and is more readily controlled with ACI impregnated with bromine, with one example facility estimate of $26,200/lb of Hg controlled at 90% using halogenated activated carbon. The DOE estimated the beyond-the-floor option to be $22,496/lb of Hg removed. The most recent report cited states that “the ACI systems have the potential to remove more than 90% of the Hg in many applications based on results from NETL’s field testing program, at a cost estimated to dip below $10,000/lb of Hg removed. However while the results achieved during NETL’s field tests met or exceeded program goals, only through experience gained during long term continuous operation of these advanced technologies in a range of full-scale commercial applications will their actual costs and performance be determined.”

Response to Comment 47: The EPA thanks the commenter for the comments submitted.

---

[52] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS Corporation, April 5, 2011, http://www.supportcleanair.com/resources/studies/file/4-8-11-URSTechnologyReport.pdf
[53] NESCAUM Report, op. cit., pp.19-20
[54] Ibid. p.19
[55] Solvay Chemicals publication “Mercury (Hg)”
[56] ICAC Report, op. cit.

Comment 48: Commenter 17807 discusses the lower chloride coals ranging from 0.05 to 0.10% in the Illinois basin, but states that it would be difficult to obtain necessary chloride levels to achieve compliance with the proposed HCl emission limit. The commenter goes on to say that other facilities will be faced with similar issues and will need to consider other coal sources to achieve compliance with the HCl limit, which will increase demand and impact long term availability of these coals and decrease fuel procurement flexibility and reliability.

Response to Comment 48: The EPA determined further fuel subcategorization is unwarranted. The EPA addresses subcategorization elsewhere in the final rule record.

Comment 49: Commenter 18033 quotes the EPA position stated in CAMR, "[a]t some point in the future, the performance of control technologies on Hg emissions could advance to the point that the rank of coal being fired is irrelevant to the level of Hg control that can be achieved…." The commenter states that while controls for Hg emissions have arguably reached this point based on the proposed MACT standard, this is not the case for acid gas control for higher sulfur coals. If a well-controlled unit burning higher sulfur coals cannot meet the standard, the commenter believes the EPA needs to revise the proposed rule accordingly through further subcategorization to ensure that all coals are able to meet the applicable standards.

Response to Comment 49: The EPA determined further coal subcategorization is unnecessary for compliance since commercially available technologies for SO_2 control exhibit superior removal performance for MATS acid gases.[57] For scrubbed units firing high sulfur coals, sufficient MATS acid gas capture is expected for compliance.[58,59] The EPA addresses subcategorization issues elsewhere in the final rule record.

Comment 50: Commenter 17775 commissioned a consultant to conduct IPM modeling runs using control technology assumptions the commenter considers to be more realistic than those chosen by the EPA. The modeling involved three runs to evaluate the consequences of the EPA's decision to regulate all HAP, not just Hg. The commenter says the reference case was run assuming CAIR was implemented in 25 states and the District of Columbia, and one sensitivity run assuming that the proposed Transport Rule would be implemented with the proposed rule with only Hg emission limits. The final run was the same as the sensitivity run, except that the proposed rule was assumed to cover all HAP. The commenter states that the run results show that regulation of the non-Hg HAP adds approximately $10.5 billion to the total system costs in the first years of compliance and over $8 billion annually in following years with the 2030 compliance cost difference at over $9 billion annually. Together with the proposed rule, the Transport rule was estimated to add $22.2 billion to total system costs in 2015, $21.1 billion by 2020 and $25.7 billion annually by 2030.

Response to Comment 50: The EPA has updated its modeling in the final rule, compliance costs are found in the RIA and the preamble for the final rule.

The agency received numerous comments regarding independent modeling analysis performed by commercial entities to contest EPA's IPM results. The EPA contends these sources incorporate

---

[57] "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" by Lipinski, Leonard, Richardson; published by URS; April 5, 2011
[58] Ibid.
[59] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" p. 19, March 31, 2011

inaccuracies within their models which dramatically influence the basis of these comments. For a discussion addressing the limitations of industry performed modeling studies, see the preamble for the final rule.

Comment 51: Commenter 19114 feels revisions are needed for the inputs to the IPM model. The commenter gives the SCR cost estimates as an example, as they are below industry estimates for installed costs and should be increased by at least 20%. The commenter also states that it is unclear if the EPA is correctly accounting for allowance for funds used during construction (AFUDC) and owner's cost on fabric filter retrofits. The commenter also asks if ACI and DSI costs include transfer, handling and storage. The commenter gives the example of IPM model results for Northeastern unit 3-4, which showed they could comply with the proposed rule using DSI. However, the commenter states that in March 2011, the EPA issued a Federal Implementation Plan requiring FGDs to reduce SO_2, making the HAP scenario proposed by the EPA unrealistic. The commenter asks that the EPA reevaluate its modeling with correct inputs based on all current and proposed rules.

Response to Comment 51: IPM calculates fabric filter AFUDC correctly for a 2-year construction cycle; the typically anticipated cycle for a fabric filter.[60] The B2 calculation description (as illustrated on the spreadsheet view) is in error. The mathematical calculation actually performed is: B2 = 6% x (CECC+B1) {incorrectly typed as: 6% x CECC + B1}.

Both ACI and DSI estimated costs calculations include all equipment from unloading to injection.

Due to surrogacy co-benefit effects of controls, FGD controls capture HAP acid gasses more efficiently than SO_2.[61] Depending upon a unit's control configuration, equipment performance and fuel characteristics, ACI may be unnecessary.[62]

Comment 52: Commenter 19114 expresses concern that the gas supply curves in the IPM model are short on supply and inelastic in the near-term, based on comparison with data from EIA's 2011 Annual Energy Outlook. The commenter disagrees that gas prices have the most significant impact on unit retirements and considers the exposure of a coal unit to future environmental constraints and potential expenditures to be the biggest factor in retirements. As such, the commenter suggests the EPA include future regulatory constraints within the model or risk understating the impact of the rule being proposed.

Response to Comment 52: Besides retrofit controls, payroll, debt service, and maintenance, an EGU's largest fiscal expense is fuel procurement with market conditions determining operational viability of an EGU. The EPA approached gas supply market conditions conservatively. The agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier

---

[60] Sargent & Lundy, "IPM Model – Revisions to Cost and Performance for APC Technologies Particle Matter Control Cost Development Methodology FINAL," March 2011, Project 12301-009, Perrin Quarles Associates, Inc

[61] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" by Lipinski, Leonard, Richardson; published by URS; April 5, 2011

[62] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" March 31, 2011

natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters. Current and projected natural gas prices significantly impact anticipated coal-fired retirements. IPM Natural Gas (NG) modeling is discussed in the preamble for the final rule.

Comment 53: Several commenters (19536, 19537, 19538) discuss the EPA's documentation of IPM modeling that shows the EPA found that the costs of complying with a 0.0001 lb/MMBtu HCl MACT limit, which would be achieved through installation of scrubbers or scrubber upgrades, installation of baghouses at fluidized bed boilers, and/or DSI with baghouses to achieve SO_2 removal efficiencies of 92% to 96%, would be cost effective. The commenters point out that the EPA did not account for the fact that numerous units will have to achieve the required level of SO_2 controls soon under other state or federal regulation to meet ambient air quality standards. The commenter goes on to list additional findings by the EPA based on IPM modeling, and agrees with the EPA's assessment that the environmental and health benefits outweigh the costs, thanks to the cost-effective technologies and methodologies summarized.

Response to Comment 53: The EPA thanks the author for the comments submitted.

The EPA's IPM modeling of MATS accounts for all finalized state and federal regulations. See RIA chapter 3 and "Documentation Supplement for EPA Base Case v.4.10_MATS – Updates for Final Mercury and Air Toxics Standards (MATS) Rule" for additional discussion.

10. Difficulties with control technologies.

Comment 54: Commenter 17702 acknowledges that they have compliance options to meet the proposed emission reduction requirements, such as adding carbon injection or switching to a wet scrubber. However, the commenter points out that these options will increase cost and defeat the environmental objectives because they will increase water use and eliminate the sale of the byproduct material from a dry fabric filter.

Response to Comment 54: The EPA does not anticipate units with fabric filters necessarily increasing water consumption because scrubber retrofit becomes unnecessary with the DSI option for rule compliance. Depending upon treatment rate and reagent (sorbent) selected, ACI or DSI may impact fly ash sales; on the other hand, activated lime reagent effectively removes acid gases and should not adversely impact fly ash marketability. Mineral-based Hg sorbents are effective and commercially available for overcoming concerns with activated carbon. [63] Additionally, see response to comment 4 (above).

Comment 55: Multiple commenters (17868, 17912, 19213) state that the EPA did not address physical space and age-of-plant issues when setting BDT, MACT, and NSPS because it did not recognize that older coal-fired power plants have space constraints and may only be able to "build up" if they install a fabric filter. This means that smaller and older plants will not be able to comply with the proposed rule. Commenter 17868 considers the EPA's projection that only 3% of the industry's coal-fired capacity will

---

[63] Hizny, W., Magno, G., Yang, X., "BASF Mercury Sorbent ZX™ for Control of Coal-fired Power Plant Hg Emissions," Paper # 176, Power Plant Air Pollutant Control "MEGA" Symposium, August 30 – September 2, 2010, Baltimore, MD

become uneconomical due to the proposed rule to be flawed and also points out that the EPA did not identify how many of the public power units will implement control technologies under separate regulations or state implementation plan changes and revisions to effluent guidelines which may take power plants offline for weeks or months in the next 5 or more years. Commenter 17868 believes the EPA's estimates of the number of plants that will require additional controls, and these impacts will hit the upper and lower midwest, southeast, and southwest the hardest.

Response to Comment 55: For discussion on available space limitations, small stations, small companies and control equipment available, see Response to Comments section 5C01 "Compliance Dates" which discusses controls for congested sites and combing emissions from multiple units into a single control device. Additional discussion is provided in the preamble for the final rule.

The agency accounts for current state air emissions regulations in its IPM modeling platform; for detailed discussion, see RIA chapter 3 and "Documentation Supplement for EPA Base Case v.4.10_MATS – Updates for Final Mercury and Air Toxics Standards (MATS) Rule."

Comment 56: Commenter 18433 states that the suggested method of controlling PM emissions from oil-fired units is ESP because the PM is generally too "sticky" from organic content to be collected reliably in fabric filters due to plugging the pore holes in the bags.

Response to Comment 56: The EPA thanks the submitter for their input. The agency responded by creating a subcategory for liquid oil-fired, non-continental units (not including Alaska-based units) – see final rule. Additionally, the final regulation will change the PM standard from total PM to filterable PM. The EPA acknowledges oil-fired units typically control PM emissions with an ESP and believes the final MATS standard for oil-fired units can be met with a well-designed, well maintained ESP for maintaining PM control. The EPA does not select any specific technology for MATS compliance; rather the standard sets permissible emission rates which allow the owner flexibility in selecting controls and fuels for compliance. See the preamble for the final rule.

11. Natural gas prices.

Comment 57: Commenter 17810 does not believe that the EPA has adequately considered the best available data on natural gas prices and supply, and requests that the EPA perform additional analyses of control options using updated information.

Response to Comment 57: The agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters.

Comment 58: Commenter 18033 considers replacing coal with natural gas to be problematic given that the cost of natural gas is volatile and makes up over 70% of the levelized cost of electricity (LCOE). The commenter describes a price spike from $6/MMBtu to $13/MMBtu in 2005 and details some of the environmental issues recently created by harvesting shale reserves. The commenter asks the EPA to examine a constructive policy framework that removes this and other regulatory impediments and promotes the deployment of advanced coal technologies. The commenter states that replacing older U.S. coal plants with advanced supercritical generation could create $1.2 trillion in economic benefits and 6 million jobs during construction as well as avoiding the release of 440 million metric tons of CO_2.

Response to Comment 58: The agency fully documents its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters.

12. Fuel switching.

Comment 59: Commenters 18433 and 19213 disagree with the assumption that all coal and fuel-oil units can be used with available control technologies. The commenters state that such fuel switching from one fuel type to another or fuel blending can be expensive, and facilities in Guam are restricted in their fuel choices and must rely on oil currently.

Response to Comment 59: The difficulties American territories experience is acknowledged. The agency created a subcategory for oil-fired, non-continental units (excluding Alaska-based units) realizing the unique situation and limitations these units face – see final rule. The MATS standard allows the owner flexibility to select controls and fuels plus establishes alternatives for compliance. See the preamble for the final rule.

Comment 60: Commenter 19114 expresses concern with the IPM analysis suggesting that units will switch fuel to meet the beyond-the-floor standard. The commenter considers this unreasonable because fuel switching could change the subcategory of the unit, thus subjecting it to a more stringent Hg limit. Also, the commenter points out that fuel switching costs used by the EPA do not account for all required coal conversion activities or for projects such as new coal unloading and coal yard facilities to accommodate subbituminous coal which is often delivered by rail instead of truck or conveyor like lignite fuel generally is. Additional facility upgrades that the commenter would like to see in the EPA's estimate include dust collection, new coal conveyers, fire protection, ventilation, ESP performance and water cannons to handle new fuel, soot and ash characteristics.

Response to Comment 60: Compliance issues, subcategories, and beyond-the-floor (BTF) issues are discussed elsewhere in the final rule record.

The agency believes that the fuel switching costs used in IPM are accurate, as explained at proposal. That said, the final rule does not require fuel switching, instead we establish numeric emission standards and sources are required to comply in any manner they choose. The IPM modeling indicates that some sources may choose to switch fuels as a valid compliance option. If sources are unable or unwilling to employ fuel switching, they can comply through the installation of controls or other means available to reduce HAP emissions. We discuss fuel switching as a compliance option elsewhere in the final rule record.

Comment 61: Commenter 17621 notes that the following comment presents the commenter's observations and experience with this [EPA's] approach to reducing HCl at a site burning Powder River Basin (PRB) coal and another site burning an eastern bituminous coal. Both of these studies were short-term in nature, with the test period of several weeks, evaluating a number of different parameters each day. Thus these results are not able to provide any insight on the long-term performance and impacts of dry sorbent injection. The commenter is not aware of other demonstrations of this approach that have been conducted by independent, third parties. However, because of their citation in the technical supporting documents for the proposed MACT rule, we also discuss tests conducted by a sodium sorbent supplier.

The commenter participated as a technical advisor in the first commercial demonstration of the TOXECON(r) process at We Energies' Presque Isle Power Plant. The project was co-funded by DOE under the Clean Coal Power Initiative. The primary objective of the project was to demonstrate the TOXECON configuration-downstream of a hot-side ESP in this case-with ACI for Hg control. A secondary goal was to determine the ability of powdered Trona injection to reduce SO_2 by 70% and also to realize some NO_X emission reductions. These pollutant reductions were to be obtained while simultaneously injecting activated carbon for Hg control (ADA-ES, 2008). The tests showed that the Trona could reduce SO_2, but that it also converted enough nitrogen oxide (NO) to nitrogen dioxide (NO_2) to produce a visible brown plume. Trona injection also reduced Hg capture by ACI significantly. Without Trona injection, the Presque Isle unit was able to maintain 90% Hg reduction at ACI rates of 1 to 2 pounds per million actual cubic feet (lb/MMacf). During Trona testing, the unit was unable to achieve a 90% Hg removal over a short 1-hour test, even when the ACI rate was increased to 4.6 lb/MMacf.

As these tests were conducted before the EPA made known its intent to regulate acid gases from EGUs, the project did not measure HCl emissions-especially not as a function of activated carbon sorbent injection rate. Therefore, these tests do not inform us about the amount of Trona or sodium bicarbonate that would be needed to meet the proposed HCl limit, nor whether that amount would cause a brown plume and/or plugging, as well as impact Hg capture by ACI. Tests by Solvay Chemicals (a major supplier of Trona and sodium bicarbonate) at a low-sulfur eastern bituminous-fired power plant (reporting ~ 0.5-1% sulfur in the coal and 50-60 ppm HCl in the flue gas) may provide some clues. In this one test campaign, Solvay Chemicals reported 50% HCl removal at a sodium bicarbonate injection rate sufficient to capture 10% of the SO_2-i.e., a relatively low injection rate (Davidson, 2010).

Since brown plumes have been observed at plants using sodium sorbents for SO_2 control, but not at plants using these sorbents for SO_3 control, it is possible that low sodium injection levels may not produce brown plumes or plugging; this may apply for western bituminous coals with coal chloride concentration slightly greater than the proposed limit for HCl. However, this may not be possible for subbituminous coals with chloride concentration greater than about twice the proposed limit, where HCl removals up to 90% may be required. The situation for eastern bituminous coals, with their higher chlorine content, is discussed below. To go beyond a reliance on engineering judgment, it is important to determine-via independent tests fully open to public scrutiny-whether these single results obtained on an eastern bituminous coal are representative of results for the fleet of PRB-fired power plants. Only then will the public and the industry truly understand the ability of sodium sorbent injection combined with a fabric filter to reduce HCl emissions to the proposed limit at plants burning western coals, and to do so without impacting plume opacity and/or Hg emission reductions.

In 1996-97, the commenter conducted tests of both sodium bicarbonate and hydrated lime DSI upstream of a pilot baghouse at Hudson Generating Station owned by Public Service Electric and Gas (EPRI, 1998). This plant burned a coal that typically contained less than 1.0% sulfur and less than 0.1% chlorine; the corresponding flue gas HCl concentration at the pilot's inlet duct was 61-97 ppm. The results of these tests, presented in the document, show that HCl reductions up to 90% could be achieved, but only at sorbent-to HCl injection ratios of about 12. For a 500 MWe plant with 100 ppm HCl, a normalized stoichiometric ratio (NSR) of 12 is equivalent to increasing the ash loading by 50-60% or by 250-300 tons/day (normal ash loading is about 500 tons/day).

The Hudson site, with an HCl concentration in the mid-range for eastern bituminous coals, would have required 97-98% HCl removal to achieve the proposed MACT limit (equivalent to ~ 2 ppm). Plots of pollutant removal versus sorbent injection rate typically become very flat at high injection rates-i.e., increase very slowly if at all with increasing sorbent injection-so it is not clear from the available data if hydrated lime or sodium bicarbonate could routinely provide greater than 90% reductions at any injection rate.

Response to Comment 61: The EPA appreciates the commenter's observations. See the preamble for the final rule for more discussion on DSI technology.

13. Miscellaneous.

Comment 62: Commenter 18033 questions the EPA assumption that 50% or more of the current fleet have scrubbing technology installed and that the number will be nearly two-thirds by 2015. The commenter says that over half of the scrubbers mentioned will be at the end of their useful life by 2015, so cost will be associated with upgrading these scrubbers to achieve compliance. Also, the commenter points out that the scrubbers were only required to achieve 70% SO_2 removal when constructed. Bringing these scrubbers into compliance will require more than modifying spray heads and adding absorber trays and could double the projected upgrade costs for older units and increase retirements. This leads the commenter to conclude that approximately 25% of the current coal-fired fleet will retire early as a result. The commenter also mentions that as the MACT floor is set on the average of the top 12%, only 6% can be expected to meet the standard without modification.

Response to Comment 62: The agency has a different outlook regarding replacement of existing control equipment. The EGU sector continuously demonstrates the ability to operate equipment beyond its originally intended lifespan (typical design life of 30 years) through replacement or upgrade of worn components. For example, 592 units (59% of the coal fired fleet) exceed 40 years of age.[64] Consequently, the agency believes owners will operate emissions control equipment well beyond a 20-year period and shall attempt the more economically attractive option of upgrading equipment rather than replacement. Depending on scrubber age and current SO_2 removal rates, a wet scrubber can be upgraded for $5-$100 per kW of unit size.[65] Furthermore, for acid gas removal compliance, an owner's option includes augmenting existing controls by installing DSI.

[64] M.J. Bradley & Associates Report; "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," August 2010, p.16; Table 5 "Characteristics of U.S. Coal Plants." Ref:
http://www.mjbradley.com/sites/default/files/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf

[65] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" by Lipinski, Leonard, Richardson; published by URS; April 5, 2011

Comment 63: Commenter 18023 reports that many of their units have SCRs and scrubbers but will not be able to meet proposed emission limits in most cases and will need baghouses and CEMS installed at a cost of $8.5 billion to comply with the proposed limits and monitoring requirements. The commenter notes that this price could increase due to the large number of plants rushing to comply with all existing and proposed regulations which could drive up the costs of materials and skilled labor. The commenter also shows that the EPA's estimate for the same facilities gives a $4 billion cost, showing that the EPA's estimates are understated.

Response to Comment 63: The EPA disagrees with commenter's assertion that the EPA's cost projection is understated, and maintains that the EPA's incremental cost projections are reasonable. The RIA includes projected controls retrofits and costs as updated in the EPA's analysis for the MATS final rule. The EPA has provided the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues. For discussion on some of the issues mentioned above, see the preamble for the final rule and Response to Comments section 5C01 "Compliance Dates." In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 64: Commenters 16826 and 17386 consider the cost and logistic burdens to comply with the proposed rule a concern because they know of a unit containing a once-through circulating water system that must meet NPDES water discharge limits. The commenters say that these permit limits indirectly restrict the hours of operation and load, and request a "Limited Use" category to relieve this and other oil-fired facilities in a similar scenario.

Response to Comment 64: Based on the concerns submitted, the EPA established a "limited-use" subcategory for liquid oil-fired EGUs. For a detailed discussion, see the preamble to the final rule.

Comment 65: Commenter 16849 reports a compression of resources available between 2007 and 2008 that led to the price of SCR installation to jump from $31 million in 2007 to $58 million in 2008 at a neighboring, like-sized facility.

Response to Comment 65: Many factors influence retrofit cost besides locality;[66] a neighboring facility does not necessarily mean an "identical" facility. The present economic conditions differ drastically from the situation experienced in 2007-2008; retrofit controls cost models were determined during this time period and based on 2009 pricing. With excess resources currently available, the agency anticipates aggressive competition by suppliers to win project award subsequently resulting in price relaxation from pre-2009 levels.

Comment 66: Commenter 17296 provides information regarding the use of calcium bromide as a cost-effective way to reduce Hg emissions from coal-fired units. The commenter says that calcium bromide has been found to effectively oxidize elemental Hg so that it can be better controlled by traditional control devices. (The commenter provides a White Paper on Calcium Bromide Technology for Mercury Reductions (August 2010) as part of EPA-HQ_OAR-2009-0234-17296-A5 and additional research as -17296, -17296 and refers to NESCAUM report "Technologies for Control and Measurement of Mercury Emissions from Coal-Fired Power Plants in the United States: a 2010 Status Report" at http://www.nescaum.org/topics/mercury.)

[66] Steam, 41st Ed. 2005, Babcock & Wilcox Company

Response to Comment 66: The EPA thanks the submitter for the information provided in support of the proposed rule. Multiple comments were received advocating control technologies that were not represented in the EPA's compliance cost analysis of the MATS proposal. The agency notes that control technologies mentioned within the proposal are neither an exhaustive nor an exclusive list, rather, these listings demonstrate proven available technologies for industry sector compliance. The EPA is not selecting, or precluding, any particular technologies in this rulemaking but is instead allowing each facility to determine its preferred means of compliance with the emission rate standards.

Comment 67: Commenter 17807 discusses a new $1.2 billion project to upgrade environmental controls and repower a power station which led to an annual reduction of Hg, SO_2, NO_X and PM emissions in 2010 by 90%, 94%, 91% and 87%, respectively, below 1998 levels. The commenter says that the EPA's proposed emissions limits will likely require further optimization and adjustments and be difficult to implement despite these recent upgrades.

Response to Comment 67: The agency set emissions standards based on data collected (ICR) from existing EGUs within the domestic EGU fleet; thereby, demonstrating operational, existing control technologies for compliance. Owners have a multitude of options and may choose to: retrofit, optimize current controls, upgrade existing controls, fuel switch/blend, employ a combination of technologies, or retire and replace power. The EPA understands recently retrofitted units may require further upgrades for compliance; however, controls for SO_2 mitigation typically suffice for MATS acid gas capture while economical upgrades of existing controls or optimization may suffice for compliance.[67]

Comment 68: Commenter 17842 believes the implementation of a "total" PM limit in the proposed rule contributes largely to the rule's estimated costs as utilities will need to replace existing PM controls with more costly fabric filters.

Response to Comment 68: Although the EPA proposed a total PM standard, the EPA is finalizing MATS to include a filterable PM standard instead. See the preamble for the final rule. The EPA does not believe that MATS automatically necessitates replacing existing PM controls with fabric filters. Many older ESPs are oversized and suffer from inadequate maintenance resulting in degraded performance; simply restoring performance will improve capture rates. Upgrading with modern components (such as: modern power supplies, electrode replacement, additional fields) or enhancing air flow and rapping allows improvement beyond original performance metrics. In fact, many older ESPs have sufficient room for extension thereby increasing collecting area by 10-20 percent.[68] As another option, an EGU may consider retaining the old ESP and install a supplemental smaller-sized "polishing" baghouse[69] to augment particulate collection. In short, the EPA does not foresee ESPs becoming obsolete with promulgation of MATS.

Comment 69: Commenter 17885 states that many cooperative EGUs will be forced to retrofit with additional emission controls under the proposed rule and others will need to shut down because they will be unable to retrofit under the timelines or cost-effectively justify the retrofits. The commenter expresses

---

[67] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" by Lipinski, Leonard, Richardson; published by URS; April 5, 2011
[68] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" by Lipinski, Leonard, Richardson; published by URS; April 5, 2011
[69] NESCAUM report; "Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power plants" p. 19, March 31, 2011

concerns with the practical application of the proposed rule and the procedures used by the EPA in the rulemaking process.

Response to comment 69: The EPA believes that the flexibility of the rule permits a multitude of options for economical compliance. Flexibility, other regulations, and compliance date attainment are discussed in the preamble for the final rule, feasibility TSD, and in Response to Comments section 5C01 “Compliance Dates.”

Comment 70: Commenter 19122 describes the startup and shutdown process for their oil-fired unit, which requires bypassing of the fabric filters to prevent damage that would require replacement of bags after each startup. Requirements that include startup and shutdown episodes in PM emissions on a lb/MMBtu basis would lead to the need to use the fabric filter with temperatures well below the acid dew point, leading to bag binding and acid degradation. The commenter explains that this would involve using at least one casing out of three in service to handle flow during start up. One casing has 16 compartments with 396 bags each. The bags in the compartment that would need replacement cost $1.2 million, leading to an additional cost of $15 million per year.

Response to Comment 70: The EPA acknowledges start-up/shut down issues involving fabric filters (acid attack, blinding, etc.) during oil firing. The agency points out that the coal-fired boiler industry overcame this issue by installing chemically resistant bags[70] and/or pre-coating the bags[71] with an alkaline powder. Another option employs firing low sulfur fuels. Additionally, the EPA established requirements for PM control during start-up, shutdown and malfunction – see the preamble for the final rule.

[70] Neundorfer web site: http://www.neundorfer.com/knowledge_base/baghouse_fabric_filters.aspx ; Lesson #4, p.7 Table 4-1 [ref.: http://www.neundorfer.com/FileUploads/CMSFiles/Fabric%20Filter%20Material[0].pdf]

[71] CoalPower mag; May 1, 2007; “Coal Plant O&M: River Locks and Barges are an Aging Workforce, Too” ref.: web site: http://www.coalpowermag.com/plant_design/Coal-Plant-O-and-M-River-Locks-and-Barges-Are-an-Aging-Workforce-Too_36.html

6G - Impacts/Costs: Testing and Monitoring Cost Assumptions

Commenters: 17197, 17386, 17681, 17696, 17716, 17718, 17730, 17737, 17761, 17772, 17795, 17796, 17843, 17856, 17881, 17886, 18014, 18444, 18502, 18023

Comment 1: Commenter 17197 believes the 18 months burner inspection interval is unreasonable because it introduces substantial costs not reflected in the cost estimates shown in Table 14 of the proposed rule. The commenter reports costs for pre-boiler entry slag blasting for personnel safety costs approximately $10-12,000, scaffolding the boiler for burner access is about $80,000 and requires at least 6 weeks of pre-planning and post-outage boiler combustion testing and tuning costs around $50,000.

Response to Comment 1: The EPA generally agrees with the commenter and has altered the burner inspection interval to reduce the cost burden of this rule. Under the final rule, the inspection and tune-up must be conducted at each planned major outage and in no event less frequently than every 36 months, with an exception that if the unit employs a neural-network system for combustion optimization during hours of normal unit operation, the required frequency is a minimum of once every 48 months.

Comment 2: Commenter 17386 objects to the requirement to conduct monthly or bimonthly performance tests, as it is an economic burden, especially for smaller facilities. The commenter also states that such testing could result in increased annual HAP emissions exceeding any reduction in hourly emission rates achieved by the rule. The commenter points out that oil is a homogenous fuel for which metal concentrations are unlikely to fluctuate. The commenter goes on to say that since oil-fired EGUs are a minor source of HAP except for nickel, the frequent testing is unwarranted. The commenter states that the cost of such a testing program involves the ancillary cost of operating the EGU on a must-run basis for the testing, even on EGUs that operate intermittently. Such testing will interfere with the ability to meet regional electricity demands if the EGUs have a monthly circulating water flow limits as part of their NPDES permit. The commenter also notes a problem for dual-fired EGUs which often operate on natural gas during the ozone season. However, for testing purposes, the commenter will be required to fire the fuel with the capacity to generate the most HAP emissions, leading to emissions that would not have otherwise been released. The commenter requests that for these reasons, the EPA require only one performance test for oil-fired EGUs be conducted every 3 years.

Response to Comment 2: The EPA recognizes the cost burden of testing and we are relaxing the testing frequency to require that oil-fired EGU's be tested at least quarterly rather than monthly or bimonthly. The EPA generally agrees with the comment regarding oil-fired testing during the ozone season and is changing the rule language accordingly to require that testing be conducted on the fuel type fired during the operating quarter that is likely to result in the highest emission rate. In this manner, if there are no oil-fired operations during ozone season quarters, there is no requirement to test while firing oil.

Comment 3: Commenters 17386 and 17696 consider monthly or bimonthly stack testing for HCl to be wasteful due to high annual costs of around $78,000 for a single stack, $127,000 for two stacks and $176,000 for three stacks. The commenters believe that a more reasonable approach would be to perform an initial stack test for PM followed by the use of PM CEMS, and annual PM stack tests as long as the coal type or mixture of fuels did not change. The commenters state that a stack test vendor estimates that annual total PM and non-Hg metals stack testing plus non-Hg metals bimonthly stack testing would impose a cost of $67,000 for one stack, $115,000 for two stacks and $162,000 for three stacks, which would be unnecessary to assure compliance if the suggested approach were used.

Response to Comment 3: The EPA disagrees with the commenters' notion that PM is an appropriate surrogate for HCl emissions. HCl testing frequency has been reduced to a quarterly requirement and is required only if SO_2 controls and monitoring, or HCl monitoring (optional) are not employed. PM CEMS and PM CPMS options are being added to this rule to optionally reduce the burden of monthly or bimonthly stack testing.

Comment 4: Commenters 17716 and 18014 discuss linearity checks required under Appendix B. Commenter 17716 states that section 63.10010(e)(6)(iii) should define the term "nominally," and should not require the introduction of a calibration gas. The commenter points out that Part 75 requirements already assure an analyzer span that provides accurate data. Coupled with the Part 75 requirements, the three linearity gas concentrations are sufficient to determine that the analyzer is linear. Commenter 18014 states that the system will need to be modified to include an additional regulator, the data acquisition and handling system (DAHS) will need to be reprogrammed and costs will be incurred for a fourth calibration gas and monthly cylinder demurrage. Both commenters state that the section 63 requirements will increase SO_2 CEMS operating costs.

Response to Comment 4: The EPA agrees with the commenter that Part 75 requirements already provide for a linear instrument response that should, by definition, include the emissions limit level and beyond, and has removed this requirement from the final rule.

Comment 5: Commenter 17718 requests guidance from the EPA on what should be included in a site-specific test plan mentioned in the proposed rule (40 CFR 63.10007(a)) as the development of quality assurance programs with testing firms can be burdensome without clear guidance.

Response to Comment 5: Section 63.100007(a) points to section 63.7(c) which contains specific information about QA programs including test plans and internal and external QA programs. The EPA is a proponent of Data Quality Objectives (DQOs) as these are the pretest expectations of precision, accuracy, and completeness of data.

An example of a DQO requirement is:

"The sample volume must be sufficient to provide the required amount of analyte to meet both the MDL of the analytical method and the allowable stack emissions. It may be calculated using the following formula:

Sample Volume = A x 100/B x 100/C x 1/D

Where:

A = The analytical Method Detection Limit in ng

B = % (%) of the sample required per analytical run

C = Sample recovery (%)

D = Allowable stack emissions (ng/dscm)

Test contractors are experienced with developing and working with Test Plans, DQOs, and QA programs and the EPA feels this requirement should not present an undue burden to facilities.

Comment 6: Commenter 17730 and 18023 discuss the Hg compliance options. Commenter 17730 believes that the proposed Hg emission standards for existing units is not based on representative data and the limit will be difficult to achieve routinely and will eliminate new coal-fired units. However the commenter appreciates the EPA's providing of the alternative of conducting fuel analysis for ongoing compliance for existing low emitting electric generating units (LEEs), and urges the EPA to make it available to new units as well. Commenter 18023 questions the EPA's assumption that "most, if not all, of the units that were subject to CAMR purchased Hg CEMS and/or sorbent trap systems prior to the rule vacatur…" The commenter reports that while their facilities did install Hg CEMS, the systems will need extensive upgrades as they will require three more CEMS be installed to meet the proposed requirements. Also, full quality assurance measures have only been completed on a fraction of the previously installed CEMS. The commenter goes on to say that the Hg CEMS have required an unexpected degree of maintenance, which will increase with lowered emission limits and some Hg CEMS have been inexplicably unreliable. The commenter believes others in the industry are in a similar situation, which means that the EPA cost estimates underestimate the cost of new installations, expensive upgrades and additional maintenance required by the proposed rule. In addition to the equipment-related expenses, the commenter lists costs associated with modifying the data acquisition and reporting systems associated with the Hg CEMS to meet the new procedures and requirements. The commenter estimates that these changes will cost approximately $20 million upfront and another $2.5 million annually.

Response to Comment 6: The EPA generally agrees with the commenter that many Hg CEMS installations were not undertaken or fully implemented as a result of the CAMR vacatur, and we are increasing our estimated cost impacts accordingly. The EPA does not agree that existing mercury CEMS installations would need upgrades to comply with this rule and the commenter provided no information demonstrating the case.

Comment 7: Several commenters (17737, 17761, 17886, 18023) comment on the burden of outage intervals required to meet the proposed rule requirements. Commenter 17737 reports that in addition to the cost of the inspection and repair work, the facility may be required to purchase power during outages at higher prices that the electricity normally produced. This cost could exceed $1 million for a 3-week outage during peak season. By requiring a major outage every 18 months, the rule makes it difficult to schedule outages for off-peak seasons when demand for power drops and replacement power is less expensive. Commenter 17761 states that major maintenance outages are generally scheduled only every 4 or 5 years. The requirement to do burner inspections every 12 to 18 months is excessive because large companies multiply these outages across a fleet of 20-30 units, making the annual costs large, increasing electricity rates and interfering with system reliability. Commenter 17886 considers the requirement of an outage for burner inspection and repair more often than every 36 months to be excessive because of increased costs without actual benefit. Commenter 18023 estimates that the impact of shortening its outage interval by only 6 months would amount to approximately $140 million for 5 years across their system, taking into account the cost of replacement generation.

Response to Comment 7: The EPA acknowledges the concerns raised by the commenters and has altered the requirement for burner inspections to a schedule more likely to coincide with planned major outage schedules.

Comment 8: Commenter 17772 requests clarification on the proposed rule language that verifies no requirement to retrofit boilers with viewing ports where none previously existed. The commenter quotes section 63.100021(a)(16)(iii) and asks that the "as applicable" provision be clarified to show if it is intended to exclude observation of flame pattern in boilers that do not have viewing ports. The commenter considers the addition of view ports to units without them costly and of little benefit as flame pattern viewing can be subjective when trying to assess CO levels and tells little about NO_X levels.

Response to Comment 8: The EPA generally agrees with the commenter and has revised the rule language as suggested.

Comment 9: Commenter 17772 discusses the option of calibrating oxygen monitors instead of calibrating all other equipment to optimize total CO and NO_X emissions. The commenter recommends that oxygen monitors be calibrated annually instead of the air flow or fuel measurement devices, as proposed in section 63.100021(a)(16)(iii). The commenter reports that air-to-fuel ratios are usually fixed by the manufacturer at the time of installation and calibration is done as needed or during a planned outage. Some systems are difficult to adjust or unable to be adjusted. Therefore, the commenter considers CO and NO_X emissions to be dependent on oxygen, so monitoring oxygen levels is a better indication of optimal emissions. In addition, oxygen sensors are more easily monitored and calibrated, and their calibration would be a better requirement. The commenter also requests that the proposed language in section 63.100021(a)(16)(iv) be altered from "…optimization should be consistent with the manufacturer's specification." to "…optimization should be consistent with burner industry operating procedures." This wording change is important because the burners are set by the manufacturer at the time of installation, but the operator is responsible for adjustments based on future operational changes such as coal quality.

Response to Comment 9: The EPA generally agrees with the commenter in that not all parameter changes are applicable at all facilities and for all burner installations. We are modifying the rule language to clarify this requirement and allow for adjustment of burners that have had post-manufacturer modifications or adjustments for fuel quality or type.

Comment 10: Commenter 17795 requests that the facility averaging requirement to not exceed current emission levels be removed on the grounds that the current language penalizes units that have controls in place and are currently meeting the EPA's HAP standards, which is counterintuitive to how these units should be viewed. The commenter lists the following reasons for the requested change in the provision:

1. Facilities in many cases do not have CEMS installed (e.g., Hg and PM CEMS) and do not know the current rate being achieved at given unit.

2. There is too much variability in emissions data to set an arbitrary emissions ceiling that may not be reflective of the upper end of the normal range of emissions at a given facility.

3. To demonstrate that the control technology is no less effective is in essence requiring an initial compliance test shortly after the rule is finalized and again 3 years later when the compliance is required. Again this scenario places too much emphasis on emissions testing and fails to recognize the variability of those tests. The commenter includes a table which shows this potential variability and the wide spread of Hg emissions (all within EPA's proposed Hg standard) at one of GenOn's facilities in the first seven months of 2011. [EPA-HQ-OAR-2009-0234-17795-A1, 17795_2011_Hg_Emission_Data.doc]

Response to Comment 10: The EPA disagrees with the comments provided. The ICR testing requirements were designed with the goal of collecting data representative of the cross section of units. The UPL calculation performed on emissions test data takes variability into account in the effort to find levels where 99% of emissions test results will fall below the set limit. Performance testing conducted to assess control technology effectiveness are standard compliance procedure.

Comment 11: Commenter 17796 considers the option of stack testing with Method 5 or 201/202 monthly or bimonthly depending on PM control equipment to be burdensome for the source and the state agencies required to witness the tests and review the reports. The commenter also points out that the proposed testing does not assure additional public health benefits.

Response to Comment 11: The EPA has modified the requirement for monthly and bimonthly testing to a quarterly testing requirement. This requirement is an option and as such is not a necessary burden for the facility to bear. The proposed testing is in lieu of continuous monitoring and as such is meant to assure that public health benefits are akin to what would be shown by continuous monitoring of emissions.

Comment 12: Commenter 18023 reports that the cost to install and operate PM CEMS for compliance with the proposed rule will exceed $30 million initially and at least $0.6 million annually.

Response to Comment 12: The EPA recognizes the costs associated with PM CEMS compliance requirements and is modifying the rule language to reduce the cost burden while maintaining continuous monitoring using the technology as a continuous parameter monitor (PM CPMS).

Comment 13: Several commenters (17796, 17761, 17843, 17856, 18444) comment on the costs for state agencies required to observe or review emissions tests, read reports and protocols related to the proposed rule, and send the EPA summaries of the data. Commenter 17843 suggests that once the initial test is conducted for PM and non-Hg metals, and fuel sampling or operating parameters are established, fuel sampling would be a simpler and less costly approach than stack testing. The commenter mentions that having the EPA revise the monthly and bimonthly testing requirement to quarterly or biannual testing would be more reasonable. Commenter 17856 also discusses the need to modify each unit's Title V permit and the time required for state agencies to complete the extensive modifications to each unit's unique operational characteristics. The commenter sees these requirements as especially burdensome because they would be required to repeat the process every two months, indefinitely, and for every unit subject to the bimonthly performance tests. The commenter states that budgetary constraints mean the states simply do not have the resources to carry out these responsibilities, so the EPA should revise the rule to alleviate this burden. Commenter 1844 mentions that minimum sample volume of 4 dry standard cubic meters (dscm) means approximately 4-hour sample runs, which will increase workload. Also, the commenter points out that some rule sections with operating limits in need of establishment will require multiple load testing, which is another resource drain for state agencies.

Response to Comment 13: The EPA generally agrees with the comments and has dropped fuel sampling requirements for non-Hg metals since the detection levels are not low enough to show compliance with the limits. This removes the requirement to update Title V permits as the rule will also drop the control device operational limits. Now, source owners/operators would establish the milliamp value during successful Method 29 testing, and use just that value as an operating limit. The EPA has also modified the rule requirement to require testing on a quarterly basis rather than monthly or bimonthly. The EPA has undertaken an effort to better assess detection limits of test methods which may serve to reduce the 4 dscm requirement in the future.

Comment 14: Commenter 17881 requests a change to report a total for all metals, rather than reporting filterable and condensable values because the separate analysis will add costs without providing necessary information.

Response to Comment 14: The EPA disagrees with the comment and is not modifying the requirement. EPA Method 29 has always included the analysis of the impinger contents for all of the metals. For several of the metals such as selenium and arsenic there are specific reagents in the impingers which are designed to collect the metals that pass through the filter. Since digestion and analyses would be required for the filterable component and digestion of the impinger contents is required for those metals with special reagents, the additional cost is due to the analysis by the ICP instrument. Since this instrument analyzes all metals concurrently, there would be no or little reduction in the analysis cost for the impinger contents. In addition, for a few of the Method 29 tests conducted for the Phase III portion of the ICR, substantial percentages of the metals were in the impinger analysis. Eliminating the results of the impinger contents would introduce a significant negative bias into the results.

Commenter 15: Commenter 18502 discusses the increased cost for non-continental EGUs of emissions testing to document compliance with the proposed limits. The commenter explains that as a non-continental unit, they contract with emissions testing firms located in the continental U.S. and have higher costs per test despite having smaller units than is common in the continental U.S. The commenter also cites the requirement to test for individual metals rather than filterable PM as a cause of increased cost of compliance testing per megawatt of capacity to be significantly higher than for continental EGUs with little environmental benefit associated with frequent emissions testing.

Response to Comment 15: The EPA generally agrees with the commenter and has modified the testing requirements and monitoring options of this rule in an effort to decrease costs to affected units.

Comment 16: Commenter 17758 states that DSI will be a useful and cost-effective control tool for many units, but it is not a viable option for all coal-based units for compliance with the acid gas standard. In many circumstances, the EPA's analysis of DSI significantly underestimates the time needed for, as well as the cost of, compliance in many circumstances. First, DSI could have limited application as a compliance option due to operational impacts and cost considerations that the EPA has not taken into consideration. Second, the use of DSI could impact beneficial use of fly ash, resulting in increased disposal volumes, costs and loss of revenue. Third, DSI is not a viable option for eastern bituminous coals, which require the use of wet FGD; compared to DSI, wet FGD is more costly and takes more time to implement, leading to timing concerns for compliance. Many companies will need more than the 3 years and will spend more than the EPA estimates to achieve compliance.

Response to Comment 16: The EPA also believes that DSI has the potential to be a useful and cost-effective control technology option for many units. We also agree that it is not an appropriate option for many facilities. Overall the EPA believes that the technology is most applicable for units burning lower-sulfur content coal (including, potentially, low-sulfur bituminous coal). The EPA has considered operational impacts and cost considerations. In some cases the EPA has assumed that a "polishing" fabric filter will be installed downstream of the primary control device. This configuration (similar to the TOXECON(tm) configuration for Hg control) allows dry sorbent to be injected after the primary PM control device, thus keeping the ash and dry sorbent (both alkaline sorbent for acid gas control and activated carbon sorbent for Hg control) separate. This will help to preserve the salability of the fly ash and may reduce the costs of disposal if the ash and spent sorbents can be disposed of separately. However, the EPA did include an analysis evaluating the impact of increased disposal costs for ash residuals that contain sodium containing sorbents (such as Trona or sodium carbonate). The EPA's analysis of the final rule includes an IPM sensitivity case using a DSI waste disposal cost of $100/ton. The sensitivity case indicates that a 100% increase in assumed DSI waste disposal cost produces slightly less than a 1% increase in the projected cost of the rule. Regarding the compliance time - this is addressed elsewhere in response to comments.

Comment 17: Commenter 17681 questions whether the EPA factored in the cost of additional catwalks required due to the additional CMS and/or sorbent trap system equipment. According to the commenter some facilities cannot place additional CMS ports where the current catwalk is located due to a lack of physical space on the stack surface area at the elevation and such additional equipment may require additional catwalk levels. Commenter notes that the Lakeland coal unit does not appear to have sufficient room on its current elevation where the monitors are located at this time for an additional monitor without bringing the integrity of the stack into question (if additional stack ports must to be carved out). Lakeland's Unit 3 coal unit already has existing monitor equipment and the addition of a PM CEMS and/or Hg monitor/sorbent may require the installation of an additional catwalk.

Response to Comment 17: The Agency's analysis represents the average cost of purchasing, installing, operating, and maintaining emissions control equipment. Application of emissions control equipment at an individual site with unique circumstances may cost more or less than the average, depending on factors such as the owner or operator's ability to engineer effective approaches that ensure compliance with the rule's emissions limits.

Commenter 18: Commenter 16849 states that the EPA makes the assumption most units currently monitor moisture content. The commenter does not measure moisture content continuously and it is their understanding that the majority of units do not monitor moisture content. The commenter asserts that the EPA needs to remove this assumption from floor and cost calculations.

Response to Comment 18: The Agency finds the commenter's concern unfounded. No assumption regarding continuous moisture content monitoring has been made for this rule, even though the Agency is aware that owners or operators of many EGUs subject to the acid rain program choose to monitor stack moisture on a continuous basis.

6H - Impacts/Costs: Projection of New Units

Comments are addressed in Section 4 of this document.

6I - Impacts/Costs: Economic Impacts/Employment Impacts

Commenters: 12050, 15002, 16469, 16549, 16705, 16849, 16856, 16858, 16859, 17004, 17022, 17026, 17028, 17123, 17137, 17254, 17265, 17386, 17400, 17403, 17409, 17620, 17623, 17627, 17629, 17638, 17639, 17640, 17648, 17654, 17656, 17676, 17681, 17682, 17689, 17690, 17692, 17697, 17698, 17701, 17702, 17705, 17707, 17710, 17711, 17712, 17716, 17718, 17725, 17730, 17731, 17732, 17736, 17743, 17745, 17751, 17756, 17761, 17765, 17767, 17771, 17772, 17774, 17775, 17791, 17797, 17799, 17800, 17805, 17806, 17807, 17808, 17811, 17812, 17813, 17815, 17817, 17821, 17824, 17829, 17834, 17839, 17840, 17842, 17844, 17853, 17854, 17855, 17867, 17868, 17875, 17877, 17879, 17880, 17881, 17884, 17886, 17887, 17901, 17903, 17904, 17909, 17911, 17917, 17919, 17921, 17930, 17931, 18014, 18016, 18017, 18018, 18021, 18025, 18026, 18030, 18033, 18038, 18039, 18419, 18421, 18422, 18422, 18424, 18425, 18428, 18430, 18432, 18433, 18433, 18433, 18435, 18436, 18437, 18441, 18447, 18477, 18478, 18480, 18481, 18484, 18486, 18488, 18489, 18497, 18498, 18500, 18502, 18538, 18540, 18575, 18907, 18933, 18961, 19041, 19042, 19114, 19121, 19199, 19211, 19212, 19213, 19214, 19580, 19653, 19536, 19537, 19538, 19742, 18023

1. Job losses and economic impact/cost.

Comment 1: Multiple commenters (16549, 17137, 17656, 17736, 17840, 17887, 17901, 17931, 18488, 18023, 19742) believe the proposed rule will weaken industry, cause job losses and hurt power consumers. Commenter 16549 reports that the proposed rule will affect 1,350 coal- and oil-fired units at 525 power plants and that NERC reports that by 2018 nearly 50,000 MW of capacity will be retired by the proposed rule. This commenters compare the various cost estimates released in addition to the $10.9 billion cost estimated by the EPA. The EIA report of $358 billion and a Representative Upton and Senator Inholfe estimate of $300 billion by 2015 show that some believe the EPA’s cost estimates to be very low. The commenters express concern for the electricity price increases that are likely to be up to 24% in some regions as a result of the proposed rule. In addition to the economic difficulty the proposed rule could place on consumers, the commenters believe that many in the energy sector will lose their jobs due to coal-fired capacity losses. The commenters believe coal-fired plants in the southeast especially will mean the loss of high-paying, high-skilled jobs and drastic price increases in energy costs.

Response to Comment 1: The agency has estimated the annual costs of the rule in 2015 to be $9.6 billion in 2007 dollars. The estimate of early retirements of coal-fired units is 4.7 Gigawatts. Both of these estimates were prepared using the IPM, a model that has been extensively reviewed and has been utilized in several rulemakings affecting the power generation sector over the last 15 years. The agency’s analyses are credible and accurate to the extent possible. Limitations and caveats to these analyses can be found in the RIA for the rule. Retail electricity price impacts are estimated to increase by 3.1% in 2015.. The agency also found that the impact on employment nationally should be small on net, with about 46,000 job-years of one-time construction labor supported or created by this rule, and a loss of 15,000 to an increase of 30,000 jobs expected on an annual basis. The agency has used peer-reviewed studies in the preparation of the employment impact analyses. In addition, commenters are not comparing apples to apples. EIA has at no time provided an analysis of the costs of MATS as proposed or finalized, and other studies showing large negative impacts have many flaws. The primary weaknesses with these studies are the poor reflection of the actual rule requirements, inadequate inclusion of proven technologies, and speculation with regards to other policy, like climate policy.

Comment 2: Several commenters (16705, 17403, 17123, 17400, 17771, 17817, 17829, 17909, 18437, 18575) express concern that the proposed rule, if finalized in its current form, will significantly impact jobs and electricity rates, leading to closed businesses. Commenter 17123 also calls for a practical, affordable, achievable energy solution. Commenter 17771 expresses concern specifically about the burden of the proposed rule on New Mexico. Commenter 17909 believes the leveling of the national electricity price and modernization of the fleet is outside the scope of the EPA's regulatory authority. Commenter 18575 expresses concern for the impacts likely in South Dakota, Minnesota and Iowa.

Response to Comment 2: The agency has estimated that there could be employment impacts on the power sector of up to 46,000 job-years of construction labor supported or created from new pollution control equipment installed, and a range of annual employment impacts of a loss of 15,000 jobs to a gain of 30,000 jobs. Although the agency does not claim what the total employment impact will be of this rule, it is important to note that there will be some positive gains in certain sectors, and overall the impact is likely to be small. The EPA estimates that there will be an increase of 3.1% in retail electricity price on average nationwide in 2015 as an outcome of this rule, with the range of increases from 1.3 to 6.3% in regions throughout the U.S. These results are found in the RIA for the rule. The agency also examined the impact of the increases in electricity prices to industries outside of the electric power sector and found that changes in product price and output should be less than 1 % in 2015 for the many industries (100) included in the analysis. There may be impacts on a firm-level that could be higher than this, but these analysis results suggest that the economic impacts on average nationally should be modest.

Comment 3: Commenter 19212 urges the EPA to give state regulators the flexibility in implementation to allow consumer protection against massive utility rate increases.

Response to Comment 3: Utilities have discretion in how to meet the requirements of this rule, and EPA analysis indicates that the impact to electricity consumers will be reasonable given the large benefits,

Comment 4: Several commenters (16858, 17022, 17028) express concern that a 10 to 20% increase in electricity costs can lead to profit loss and job loss. The commenters believe that the most effective way to protect the environment is to ensure economic prosperity so that resources are available for improvements.

Comment 5: Several commenter (17004, 17022, 17026, 17028) report being advised by their utility provider that the proposed regulation could result in double-digit price increases for power.

Response to Comments 4 - 5: The agency's analysis in the RIA for the rule finds that retail electricity prices will increase by 1.3 to 6.3% in 2015. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the agency's analysis. In addition, the agency finds that sectors experiencing these electricity price increases will not experience increases in prices or decreases in output of more than 1 %. The agency believes the economic impact of this rule is modest in light of the benefits that will accrue to those who will now experience less pollution of HAP and other pollutants than previously.

Comment 6: Commenter 17842 questions the lack of consideration of the cumulative effects of interrelated rules, which may collectively lead to more retirements. The commenter states that local utilities have reported temporary job gains due to the replacement of retired generation, but a net decrease in full-time work. The commenter asks the EPA to reassess the costs and impacts of the proposed rule.

Commenter 18424 states that the EPA's conclusion that bituminous coal production will increase as a result of Utility MACT is based on two flawed assumptions. First, as discussed above, the EPA assesses the impacts of the Utility MACT as if it were the only regulatory driver affecting a company's compliance and economic decisions. The EPA analysis ignores the cumulative impact of all the new CAA regulatory requirements a utility will have to consider when it determines its compliance strategy. As a result of ignoring the cumulative impacts on decision making by utilities, the EPA projects approximately 10 GW of coal units will be retired because of Utility MACT. In contrast, the NERA analysis, which considers the impacts of both Utility MACT and CSAPR together, projects nearly 48 GW of coal unit retirements - most of which are smaller and older units burning bituminous coal. Other studies predict similar levels of coal unit retirements. This degree of retirements would have a devastating impact on Indiana's coal industry and consumers of electricity.

Response to Comment 6: The final CSAPR was included in the baseline analysis for MATS. The agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: 1) the various EO requirements that the agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low-benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, the EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation. The EPA analysis also indicates that there will be relatively modest amounts of retirements and installation of pollution controls will be a cost-effective compliance measure. In addition, many coal facilities have already invested in pollution controls, and they are well positioned to comply with this rule with modest changes to operations. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 7: Commenter 17824 reports that the majority of coal-fired units that do not have scrubbers are small units that may find the cost of upgrades too expensive and will shut down instead, leading to job loss and decreased local revenue.

Response to Comment 7: The requirements of the rule do not mandate a particular technology, and there are other options available to utilities that will assist with compliance. In addition, the EPA has included in its analyses various cost functions for pollution controls that reflect differences in cost across unit sizes, and the projected impacts reflect these effects.

Comment 8: Commenter 17639 encourages the Federal Government to implement cost benefit and job impact analyses before enactment of all rules and regulations. This commenter also states that the proposed rule compliance costs would make it challenging for older coal-fired units to comply and lead to retirement and energy cost increases of 17.6% in 2016. These increases would disproportionately affect economically vulnerable families.

Comment 9: Commenter 18502 believes there is a disjunction between the President's public policies and the proposed rules as they relate to job creation, public burden, and economic development. The commenter cites EO 13563, EO 13132, EO 12866, and EO 13211 as the Executive Orders of concern.

Response to Comments 8 - 9: The agency followed all requirements under Executive Orders 12866, 13563, 13132, 13175, 13045, 13211, 12898, and the Unfunded Mandates Reform Act in preparing this proposed rule. The analyses completed in adherence to these requirements can be found in the RIA and in various TSDs in the public docket for this rulemaking. The agency estimates a nationwide retail electricity price increase of 3.1% in 2015 in response to this rule. The agency is mindful of the potential impacts of retail electricity price increase in response to the rule, but state and local agencies are best equipped to develop rate structures that may mitigate these price increases. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. This is also consistent with the economic literature on this subject.

Comment 10: Commenters 17656 and 18023 quote an IHS/Global Insight estimate that every $1 billion spent on upgrades to comply with the proposed rule will put 16,000 jobs at risk and reduce gross domestic product (GDP) by as much as $1.2 billion.

Response to Comment 10: The agency's modeling of impacts for this rule is concentrated on effects to the electric power sector. Our analysis of employment impacts finds a short-term impact of 46,000 job-years supported or created, with a longer-term impact of between a loss of 15,000 jobs and a gain of 30,000 jobs annually. We do not include impacts of employment beyond the regulated sector. We do not provide an estimate of a change in GDP. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. This is also consistent with the economic literature.

Comment 11: Commenter 17840 considers the proposed rule to discourage technology improvements, raise electricity costs and harm the economic well-being of the country, so the EPA needs to rescind the proposed rule.

Response to Comment 11: The EPA has designed a rule that is intended to offer flexibility, to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA. History has shown that industry adapts to regulations and finds more cost-effective compliance approaches that the EPA can anticipate or predict, thus lowering the actual cost of its rule relative to what the EPA initially projected. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices.

Comment 12: Commenter 17839 questions the concerns expressed about increased costs for electricity consumers. The commenter states that public utility commissions in each state will determine a fair and reasonable rate structure. The commenter states that any increased cost to the utility caused by the proposed rule will be amortized as a capital expenditure over a number of years, reducing the rate impact. The commenter calls on utilities to substantiate their claims of increased costs and points out that it is not the EPA's responsibility to factor rate increases into the adoption of the proposed rule.

Response to Comment 12: The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 13: Commenter 17716 rejects the EPA's view that the proposed rule will encourage energy efficiency savings to offset higher electricity costs. The commenter points out that table 23 of 76 FR 25074 does not support this claim and shows only a slight reduction in compliance costs from 2015 to 2030.

Response to Comment 13: The EPA believes energy efficiency measures can be a complement to this rule, and can be an important tool in helping address emissions. The EPA has not included all the likely additional energy efficiency measures that are likely to occur by 2015, but will continue to pursue energy efficiency improvements throughout the economy, along with other federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. A reduction in compliance costs with the rule does take place over time, and so does a reduction in retail electricity price increases across the U.S. as seen in the RIA for the rule. Thus, while this reduction in impacts is modest, it does suggest that energy efficiency increases may somewhat mitigate the impacts of the rule.

Comment 14: Commenter 17868 refers to the American Coalition for Clean Coal Electricity (www.cleancoalusa.org) projecting net nationwide employment losses totaling 1.44 million job years by 2020 as a result of the proposed rule.

Response to Comment 14: The estimate of employment losses supplied by the commenter reflects a cumulative estimate of employment losses over the time period of 2012 to 2020 related to implementation of both the CSAPR and the MATS proposal, and has many weaknesses. Thus, this estimate is not for the proposed rule alone, and is not a transparent analysis whose assumptions and inputs can be verified. In addition, the report upon which this estimate is based (NERA report, September 2011) does not show what type of employment impacts are assessed (construction, operation, etc.). The Agency's estimates both short-term and long-term employment impacts specific to this rule, which can be found in the RIA for the rule. The updated employment analysis for the final rule shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. This is also consistent with the economic literature.

Comment 15: Commenter 19042 presents the results of an analysis by the EOP Foundation on the proposed rule. The commenter estimates that the proposed rule will increase federal outlays by $286 million annually due to electricity purchases and costs absorbed by federal agencies for boiler modifications. The analysis shows increased annual federal agency costs from $1 million to $17 million annually per region, or an increase of 1 to 5%.

Response to Comment 15: The agency has considered this data as part of its UMRA analysis for the final rule.

Comment 16: Commenter 18023 estimates that capital spending and fuel switching required for compliance with the proposed rule could increase electricity prices by 10 to 20% over the next 10 years in the south. The commenter also cites a NERA analysis showing a 10 to 25% increase in the same timeframe, with job losses of 250,000-500,000. These losses could result in financial difficulty for local governments dependent on tax revenues that have a short time period in which to implement budget cuts. The commenter estimates that there are 6 to 10 jobs at a coal-fired EGU for every job at a comparably sized NGCC EGU, and the jobs lost to coal-fired EGU closures are among the higher quality jobs. Also, jobs associated with mining and transportation of coal will be lost, creating a net loss of jobs for decades.

Response to Comment 16: The agency's analysis of impacts on retail electricity prices resulting from this rule shows that there is an average increase nationwide of 3.1% in 2015, with a range of increases from 1.3 to 6.3% in that same year. The employment impacts estimated by the agency include a short-term increase of 46,000 job-years of construction labor, and a range of impacts on long-term labor from a loss of 15,000 to an increase of 30,000 jobs annually nationwide. We disagree that the rule will cause the size of impacts that are presented in the NERA analysis, which actually estimates the impacts from four EPA power plant rules - not just from MATS, and has many flaws. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. This is also consistent with the economic literature.

Comment 17: Commenter 17761 expresses concern about the potential impacts on electricity rates and grid reliability problems created by the proposed rule and the cost of replacement generation alternatives. (The commenter shares the following link to the organizations resolutions concerning the proposed rule: See Resolutions ERE-5 and EL-3 at: http://summer.narucmeetings.org/2011SummerFinalResolutions.pdf and http://www.naruc.org/Resolutions/Resolution%20on%20the%20Role%20of%20State%20Regulatory%20Policies%20in%20Development%20of%20Fed%20Enviro%20Regs.pdf.)

Comment 18: Commenter 17877 urges the agency to include in its consideration the negative impacts of increased electric power costs as it finalizes the rule and believes that significant changes should be made to the proposed standards.

Comment 19: Many commenters (17829, 17830, 17831, 17889, 17892, 18480, 18481, 18924, 19564, 19565, 19574, 19581, 19601) express concerns about the negative impacts that the proposed rule could have on the economy and ask that the EPA reconsider the rule.

Response to Comments 17 - 19: The EPA has designed a rule that is intended to offer flexibility, to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA. History has shown that industry adapts to regulations and finds more cost-effective compliance approaches that the EPA can anticipate or predict, thus lowering the actual cost of its rule relative to what the EPA initially projected. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices.

Comment 20: Commenter 17919 discusses the impact on the Federal Budget Deficit. The commenter explains that the federal government is a major consumer of electricity, and the proposed rule is estimated to increase the federal outlays for electricity by a minimum of $286 million annually, plus embedded energy costs associated with good and services. States and municipalities will be likewise impacted.

Response to Comment 20: The UMRA analysis done by the agency covers impacts to states and municipalities and shows the results in aggregate in the RIA for the rule. We have considered the federal impacts presented by the commenter in the analyses for the final rule as well and found them to be reasonable in light of the expected benefits of the rule.

Comment 21: Multiple commenters (12050, 17844, 17854, 17875, 17880, 18025, 18421) support the EPA's impact analysis and dispute claims by other commenters that the projected rule will harm economic growth. Several commenters (12050, 17875, 18421) mention testimonials by power company CEOs stating that the proposed rule will not affect the economic health of the industry and a survey showing nearly 60% of the coal-fired units already comply with the EPA's proposed Hg standard, as well as several other meaningful quotes from utility executives. Commenters also point out that 17 states already require plants to address Hg pollution, with some imposing more stringent emission limits than the EPA proposes. Commenters believe that utilities use the threat of power plant closures and lost jobs to delay Hg reductions from coal-fired plants. Commenters 17875 and 18421 also believe that the rules will drive innovation and job creation as new technologies to reduce pollution are created. These commenters, along with commenter 18478, quote the Economic Policy Institute finding that the proposed rule will increase job growth by 28,000 to 158,000 jobs by 2015 (including approximately 56,000 direct jobs and 35,000 indirect jobs), the University of Massachusetts study that showed an increase in 1.4 million jobs in 5 years, and the Constellation Energy Group installation project that employed nearly 1,400 skilled workers. Commenters 17844 and 17854 also cite the University of Massachusetts study statement that a net gain of over 4200 long-term operation and maintenance jobs will result.

Response to Comment 21: The agency thanks the commenters for their comments. The agency's estimates of employment impacts, which are found in the RIA for the rule, are smaller than the commenters' though we use a different methodology that focuses on impacts to the electric power sector. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 22: Several commenters (17265, 17638, 17681, 18023) express concern about the impact of the proposed rule on electricity rates and Florida's economy and job loss. Commenters believe the EPA has underestimated the impact. Commenter 17265 reminds the EPA of the Presidential Order 13563 which calls for the EPA to exercise its authority to minimize burden, explore all other options and include discussion in the preamble of measures evaluated. Commenters 17681 and 18023 point out that by 2015 these impacts will disproportionately affect the elderly, minorities, and low income populations, resulting in:

1. Average electricity rate increase of nearly 25%
2. Gross State Product loss of nearly $18 billion (nearly 2.5%)
3. Annual job losses of 157,000
4. Unemployment rate of nearly 13%
5. Lost annual manufacturing output of $1.3 billion
6. Lost annual state and local government tax revenues of $2.1 billion
7. Additional costs for control and monitoring equipment, upgrading transmission capabilities and impacts to municipal generating utilities.

Response to Comment 22: The agency has estimated economic impacts to the extent possible and as accurately as possible. The agency is also mindful of EO 13563, and has included an extensive discussion in the preamble of measures and options evaluated in the course of designing this rule. The agency estimates an increase in average retail electricity price nationwide of 3.1% in 2015. The agency also estimates employment impacts of an increase nationally of 46,000 job-years due to construction of new pollution control equipment, and a range of a loss of 15,000 jobs to a gain of 30,000 jobs nationally for operating this equipment. We do not include employment estimates specific to individual states due to a lack of specific information to provide credible estimates. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 23: Commenter 19580 believes that if the EPA finalizes this rule it is only a matter of time before our strong manufacturing base moves overseas, taking high wage jobs. The commenter sees the proposed rule as an excessive regulation that will cost billions of dollars, lead to higher electricity prices and job losses as well as compromising reliability.

Response to Comment 23: The EPA has designed a rule that is intended to offer flexibility, to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA. History has shown that industry adapts to regulations and finds more cost-effective compliance approaches that the EPA can anticipate or predict, thus lowering the actual cost of its rule relative to what the EPA initially projected. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices. Based on the information provided in the RIA and supporting materials, the EPA does not agree that the impacts of this rule will transfer significant industrial production overseas.

Comment 24: Several commenters (19536, 19537, 19538) state that the EPA is obligated to impose lower HCl emission limits because the cost-benefit analysis did not quantify the improved reductions of other acid gases such as HF that should be achieved with HCl controls, and the EPA's cost-benefit analysis likely underestimates true benefits of a 0.0001 lb/MMBtu HCl limit. Also, commenters point out that the EPA analysis does not take into account the SO_2 controls required to meet other rules, so the costs are likely to be overstated.

Response to Comment 24: The agency has quantified the reductions in HF emissions as part of its analysis of the impacts of setting HAP emissions limits as part of the rule. We are unable to monetize the benefits of such emissions; this is also true of other acid gas HAP reductions that could occur as a result of this rule. Finally, the agency has included SO_2 controls in existence or planned that it is aware of for sources to be subject to this rule in the baseline for the analysis presented in the RIA.

Comment 25: Commenter 17648 believes the proposed rule will promote long-term economic health by encouraging investment in modern, efficient EGUs. The commenter cites upgrades to existing nuclear plants to improve zero-pollution nuclear generation by several gigawatts, investments in alternative, renewable technologies, co-generation, improved energy-efficient combined cycle gas-fired plants, modern coal-fired plants, coal gasification combined cycle plants and technology to recover domestic shale gas resources as potential opportunities.

Response to Comment 25: We thank the commenter for their comments and the data they have provided. The agency's employment impact analysis does not include estimation of impacts using this BLS data, but we think our analysis of employment was appropriate given our approach and the data available to the agency for the proposal. Investment in more modern power generation capacity and pollution control technology is a likely outcome of this rule. The agency does believe that retail electricity prices nationwide will be higher in 2015 as a result of the rule, though that increase is modest (3.1% on average in 2015, with a range of regional impacts from 1.3 to 6.3%).

Comment 26: Commenter 18419 cites the Edison Electric Institute study of impacts from the proposed rule and found that 50% of the U.S. coal fleet may be unavailable by 2015 due to insufficient time to acquire controls or find replacement generation. In addition, the commenter notes that the study shows that utility providers will spend up to $20 billion in the next 50 years disposing of coal ash, and the proposed ozone limits are also a concern if lowered to 0.060 ppm because 13 of 14 monitored counties in Alabama will become non-attainment areas. According to the commenter, nationwide, 85% of monitored counties will become non-attainment for ozone and the cost for coming into attainment will be $20-$90 billion annually.

Comment 27: Comment 18488 cites the ICF report that concludes the proposed rule will impose incremental capital costs on industry of $141-247 billion and will lead to significantly more retirements than the EPA predicts, leading to reliability issues and increases in costs.

Response to Comments 26 - 27: The EPA has designed a rule that is intended to offer flexibility, to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA. History has shown that industry adapts to regulations and finds more cost-effective compliance approaches that the EPA can anticipate or predict, thus lowering the actual cost of its rule relative to what the EPA initially projected. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. Studies done by industry have several flaws, including a poor reflection of the actual rule requirements, inadequate inclusion of proven technologies, and unsupported speculation with regard to other policy, like climate policy. Changes to the national ambient air quality standards for ozone are not a subject of this rulemaking.

Comment 28: Commenter 18023 states that the estimated costs do not include billions of lost economic productivity that may be incurred due to load shedding to manage the bulk power system.

Response to Comment 28: The EPA has designed a rule that is intended to offer flexibility, to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA. History has shown that industry adapts to regulations and finds more cost-effective compliance approaches that the EPA can anticipate or predict, thus lowering the actual cost of its rule relative to what the EPA initially projected. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices.In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand.

Comment 29: Commenter 17682 requests the EPA consider the added cost impacts for generation of electricity from coal, the cumulative impacts of new wind turbines and solar panels and new electrical distribution lines.

Response to Comment 29: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies, like wind and solar, and does not show that the rule will lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand.

Comment 30: Commenters 17702 and 18033 quote the proposed rule estimate of a 3.7% price increase for electricity in 2015, 2.6% in 2020 and 1.9% in 2030. Commenter 17702 believes this increase will impact areas with dependence on coal and oil generation more than other regions, and the prices there will increase more. The commenter encourages the EPA to work with state and federal energy and environmental regulators to craft solutions that will enable utilities to comply with the proposed rule and other EPA rules to minimize cost impacts to consumers.

Response to Comment 30: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 31: Commenter 18033 considers the low estimate of early retirements to be one reason the EPA's impacts are so much lower than other estimates. The commenter explains that the biases within the EPA's model are incorrect because the model assumes that regions with excess supply will absorb the capacity lost by retirements, making retirement decisions a product of geography rather than economic factors.

Response to Comment 31: The EPA has conducted detailed updated economic analysis of the rule, and believes that the impact on potential retirements to be driven by both economic and geographic (locational) considerations, which the EPA modeling fully reflects. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 32: Commenter 18961 cites a study done by a consortium of electric companies that found, "Industry data counter concerns that it will cost the industry too much to comply with EPA's proposed air regulations, that pollution controls cannot be installed soon enough, or that the EPA regulations will lead to the closure of otherwise economically healthy power plants." The commenter reports that the study also notes that the proven technologies for controlling Hg and other air toxics are commercially available, and adds that the coal-fired units that are most likely to be retired in the face of the new rule are smaller, 40- to-60-year old units that are already "economically challenged" and nearing the end of their design life expectancies. (Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability, M.J. Bradley & Associates LLC and Analysis Group. August 2010. http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf)

Response to Comment 32: The EPA agrees with the commenter. The EPA has conducted detailed updated economic analysis of the rule, and believes that the impacts to be reasonable given the large benefits.

Comment 33: Commenter 17761 states that the impact analysis conducted by the EPA is inaccurate and not comprehensive and needs to be revised to account for true costs and benefits of the rule on regulated entities and the general public.

Response to Comment 33: The EPA has conducted as detailed and comprehensive an updated economic analysis of the rule as reasonably possible to reflect the true costs and benefits, and commenter does not substantiate the claims made.

Comment 34: Multiple commenters (16549, 17114, 17639, 17698, 17782, 18033) ask that the EPA delay indefinitely its proposed Utility MACT rule until further study can be undertaken on the potential costs and negative incomes to industry, jobs, and consumers. Commenters state that the current compliance deadline of 3 years does not meet the tests of reasonability or realism.

Response to Comment 34: The EPA does not have the flexibility to delay the rule, which is governed by a consent decree and the requirements of the CAA. However, it has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. The EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls.

Comment 35: Several commenters (17811, 18436, 18478) offer support for the EPA's proposed rule, stating that many power plants currently utilize the technology required and the EPA is providing adequate flexibility in the requirements by allowing facility-wide averaging for all HAP emissions from existing units in the same subcategory, effectively providing for equivalent, less costly technology in achieving the proposed emission standards. Commenters 17811 and 18436 encourage the EPA to move forward with implementation, as the commenters feels it would be too costly to not regulate toxic air pollutants. The commenters provide information from the Jefferson County Health Dept. in Alabama that estimates 15 manufacturing businesses and roughly $5 billion in economic investments were lost in the Birmingham metro area due to non-attainment air quality status.

Response to Comment 35: We thank the commenters for these comments. The EPA notes that the rule does not require specific technology, but that the level of performance called for by the rule is currently being achieved by a number of sources using certain technologies. The agency will be flexible in allowing sources to comply with this rule consistent with the requirements of the CAA.

Comment 36: Commenter 17877 believes that finalization of the proposed rule will result in increased costs that non-profit cooperatives will need to pass on to consumers, which will negatively impact economic development and jobs.

Response to Comment 36: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 37: Commenter 18025 reports that their plants are among the cleanest, most environmentally responsible coal-fired plants in the nation due to the addition of more than $1 billion in control technologies and cleaner-burning generation. The commenter states that these installations were successfully coordinated with unit outages and position the facilities to comply with the proposed rule in advance of the deadlines.

Response to Comment 37: The EPA believes that coal units that have already installed pollution controls will be well situated to comply with this rule by taking relatively modest steps to ensure compliance. The EPA also believes that the pollution control installations can be managed by industry. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate.

Comment 38: Commenter 18033 quotes legislative intent in The House Report on Section 112 that states: "In the determination of MACT for new and existing sources, consideration of cost should be based on an evaluation of the cost of various control options. The Committee expects MACT to be meaningful, so that MACT will require substantial reductions in emissions from uncontrolled levels. *However, MACT is not intended to require unsafe control measure, or to drive sources to the brink of shutdown."* The commenter believes the EPA's proposed rule runs counter to this intent. Commenter 18500 also reminds the EPA of Congress's statement and states their belief that this is exactly what the proposed rule, in combination with other new or pending rules, will accomplish in addition to impairing electric reliability and increasing costs.

Response to Comment 38: The agency is not requiring the use of any unsafe control measure. Measures that could be applied by sources to meet the rule requirements are well-demonstrated and are already in use at a substantial number of utilities, as explained in the preamble to the rule. In addition, the agency has estimated that less than 2% of all coal-fired generating capacity may be uneconomic to maintain and removed form operation by 2015 in response to the rule, and this result is the product of business decisions rather than a specific requirement of the rule. This analysis has been updated for the final rule.

Comment 39: Commenter 18421 supports the EPA's proposed rule and explains that new standards are always met with claims of infeasibility and impracticality. Yet, the commenter states that history shows the reverse to be true. The commenter outlines proven benefit-to-cost ratios of up to 23 to 1 for EPA regulations from 2000 through 2010 and economic growth and benefits from public health. The commenter also outlines cost-benefit ratios for regulations from 1970-1990 that show a net benefit in present value over the period were $22 trillion and the benefits outweighed the costs by 40 to 1.

Response to Comment 39: The EPA generally agrees with commenter’s stated views. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. The rule will also result in benefits that are many times larger than the cost of compliance.

Comment 40: Commenter 18422 believes the proposed rule will negatively affect a significant portion of the industry and its customers since nearly half of electric generation is fueled by coal, making the proposed rule a threat to reliability and affordability. The Commenter requests that the EPA reconsider the regulating of acid gases as they are not required and will impose greater cost and difficulty.

Response to Comment 40: The EPA has designed a rule that is intended to offer flexibility, to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA. History has shown that industry adapts to regulations and finds more cost-effective compliance approaches that the EPA can anticipate or predict, thus lowering the actual cost of its rule relative to what the EPA initially projected. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices.

Comment 41: Commenter 18430 believes that job losses and cost burdens for consumers will outweigh any benefit from the proposed rule and asks that the EPA reconsider the rule in light of the public comment and withdraw the proposed rule until further impact studies can be done.

Response to Comment 41: The EPA does not have the flexibility to delay the rule, which is governed by a consent decree and the requirements of the CAA. However, it has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. The EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their title V permitting authority if the source needs that time to install controls.

Comment 42: Multiple commenters (17682, 17701, 17765, 17761, 17813, 18433, 17904, 17930, 18023, 18484) express concern that the rule will result in rate increases for consumers. Commenter 18023 notes that less affordable electricity prices would have other indirect consequences, such as the loss of energy-intensive manufacturing operations, the loss of U.S. manufacturing jobs, a decline in tax revenues, and risk to national security if military bases and key manufacturing and production operations do not have a steady and reliable supply of electricity. Commenter 17765 states that utilities are already requesting residential rate increases of up to 19% (see http:/ /www.courier-journal.com/article/20110525/BUSINESS/305250080/LG-E-seek-19-rateincrease) and points out that recent regulatory impact studies predict electricity prices will rise by as much as 25% in some regions of the country (see “Proposed CATR +

MACT," NERA Economic Consulting, Draft May 2011). Similarly, commenter 17904 cites research conducted by Bernstein that predicts costs in both the PJM and MISO RTOs are expected to go up significantly and remain volatile.

Commenter 18484 believes the proposed rule will cause irreparable harm to the economy and national security due to energy cost increases negatively affecting the ability to compete in the global market and increasing unemployment. The commenter believes increased energy costs will harm the development of mineral resources and the mining industry, resulting in fewer projects and jobs and increasing dependency on foreign resources. The commenter explains that coal currently provides around 50% of electricity in the U.S. and the nation has coal reserves to continue this for hundreds of years without even considering the massive coal reserves in Alaska. The commenter also says that coal resources have less environmental impact in many cases that alternative energy production since coal produces 100 to 1000 watts per square meter of land, while solar produces 4 to 9 watts/square meter, wind produces 0.5 to 1.5 w/sm and biomass produces 0.5 to 0.6 w/sm. The commenter states that the EPA needs to complete a cost-benefit analysis that reflects the cumulative impacts of using one compliance technology to control one pollutant on the ability of other technologies to control other pollutants and that reflects the cost for makeup energy for lost generation and the ultimate cost increases for consumers. The commenter asks the EPA to include the cost of the hundreds of thousands of new wind turbines, solar panels and electrical distribution lines and consider if citizens would prefer to subsidize uneconomic energy sources, such as wind, solar and bio-fuels or not implement the proposed rule. The commenter also explains that the proposed rule with cost the government more money for electricity as well, resulting in less money for basic services, including other environmental programs. The commenter requests that the EPA withdraw the proposal and develop a more balanced rule.

Response to Comment 42: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 43: Commenter 18489 believes the estimated compliance cost of $10.9 billion will impact the economy and jeopardize the recovery our nation needs.

Response to Comment 43: As discussed elsewhere in this document, the EPA has conducted detailed impact analysis of the rule, which does not show significant impacts to the economy, and the costs of the rule are greatly outweighed by the benefits.

Comment 44: Commenter 18907 foresees negative effects for smaller businesses, including retail gasoline outlets.

Response to Comment 44: The EPA does not anticipate a notable impact on retail gasoline outlets as a result of this rule, and its detailed economic analyses, discussed elsewhere in this document, show the impacts to businesses and consumers to be relatively small.

2. State/regional impacts, low income.

Comment 45: Commenter 17731 expresses concern that the EPA's overview of the price increases does not see the hardships that will be the reality of increased prices on low-income or fixed-income households or small businesses. The commenter reports increases of $90 million in capital costs, $11.4 million in annual operating costs and $6.4 million in annual debt service costs to achieve compliance, which will lead to a 13% increase in rates for the proposed rule, and a 41% increase for all proposed and new regulation compliance costs. The commenter argues against the EPA's view that energy efficiencies will offset rate increases, because low income customers will need to use less electricity due to economic necessity. The commenter also sees large price increases for customers if units are converted to natural gas, which is approximately 2.5 times more expensive than the coal that the commenter currently uses to generate electricity.

Response to Comment 45: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 46: Commenter 17743 expresses particular concern over the proposed rule's impacts on the Oklahoma economy, such as the potential increase of electricity rates and resulting economic impacts on residents and businesses.

Response to Comment 46: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 47: Commenter 17772 is a utility with a large percentage of coal-fired generation. As such, the commenter's concern is the ability to meet customer's needs for electricity if the proposed rule is finalized, since it will lead to unit closures.

Response to Comment 47: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 48: Commenter 19213 states that the proposed rule could result in the retirement of one or more units and increased electricity rates in Illinois, driving out businesses.

Response to Comment 48: The agency has estimated that less than 2% of all coal-fired generating capacity may be uneconomic to maintain and removed form operation by 2015 in response to the rule, and this result is the product of business decisions rather than a specific requirement of the rule. The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 49: Commenter 19214 believes the EPA should expand the quantity and quality of their review so that accurate, realistic and broadly-accepted expectations of the cost, development timeline and performance of emission control systems can be considered in the final rule.

Response to Comment 49: The EPA has revised the detailed impact analysis of the proposed rule for the final rule in a number of ways, and believes that the analysis presents an accurate and comprehensive evaluation of the rule's impacts. The analysis includes the specific operating parameters and variability of other technologies, and is unlikely to lead to extensive substitution away from coal-fired generation. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 50: Commenter 17911 questions the accuracy of the RIA and states that the EPA skipped a number of procedural steps in their effort to meet the rule deadline. The commenter questions the EPA's estimates as a result and calls into question the EPA's estimates of the following:

1. Impact of Rule on the National Economy
2. Increase in Electric Rates (commenter expects costs to increase by several percentage points)
3. Financing costs for emission retrofits
4. Loss of external revenue streams from sale of CCR
5. Increased costs for disposal of CCR
6. Loss of revenue from increased parasitic load at power plants
7. Decrease in Disposable Income
8. Increase in Cost of Operation for Small Political Subdivisions

The commenter requests that EPA conduct a more robust study of the economic impact of this rule.

Response to Comment 50: The EPA has analyzed many of these impacts, which can be found in the RIA of the rule. The EPA has not analyzed the impact of other regulations, which will be conducted in accordance with the relevant requirements for each individual rulemaking (like CCR).

Comment 51: Commenter 17774 discusses plant closures in South Carolina which are expected to occur in response to the proposed rule. The commenter disagrees with the EPA's prediction of job gains and believes job losses will be focused on coal-dependent regions like the southeast.

Response to Comment 51: The agency's employment impact analysis for the proposed rule shows some increase in short-term (i.e., by 2015) employment associated with the installation and operation of pollution control equipment. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule in the long-term, but overall expects the employment impact in the short-term and long-term to be relatively small in comparison to the affected sector and the overall economy. This is also consistent with the economic literature.

Comment 52: Commenters 18424 and 18425 believe the EPA has underestimated the impact of the proposed rule on EGUs burning bituminous coal and will severely impact the Indiana coal industry and Indiana jobs in general. The first commenter explains that Indiana produces bituminous coal and expects severe job losses in coal, mining and transportation industries, which will have a multiplier effect causing more job losses throughout the state. The commenter quotes an ICC study showing Indiana job losses at more than 12,000 due to the loss of coal production. The commenter also notes that the cost of compliance will increase electricity costs and erode the competitive advantage enjoyed by Indiana in manufacturing, leading to a total loss of 50,000 jobs in the state.

Response to Comment 52: The EPA's analysis of the rule shows that it is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. This is also consistent with the economic literature.

Comment 53: Commenter 16849 believes the proposed rule creates undue burden due to straying from the cohesive air quality program goals embracing multi-pollutant control strategies. The commenter also believes that midwest states will bear a disproportionate burden for compliance due to coal-fired generation utilization.

Response to Comment 53: The EPA analysis shows that industry can comply with the rule largely by installing pollution controls, and coal will continue to remain an important part of the generation mix. By addressing revisions to the NSPS and standards for emissions of mercury and other HAP, and by accounting for the multi-pollutant co-benefits of the rules, the EPA has sought to coordinate requirements for the control of multiple pollutants and thus is being responsive to the goal of multi-pollutant control strategies.

Comment 54: Commenter 19041 expresses concern that the proposed rule will have effects on the ability of their cooperative to provide affordable and reliable service to consumers in Ohio. The commenter reports that the cooperative has already installed SCR on coal-fired units, and has or is installing scrubbers all for around $1.8 billion but is concerned that it will not be enough to comply with the proposed rule.

Response to Comment 54: Utilities that have already installed pollution controls are likely to be well positioned to comply with this rule with modest modifications.

Comment 55: Commenters 19653 and 19199 state a concern that the proposed rule will have an impact on the price of electricity in Indiana. The commenter sees the price of energy to be a major cost of doing business, and worries that increases in energy costs will negatively impact businesses. Commenter 19653 especially expresses concern about the construction industry because the electricity cost impacts on construction could limit availability of affordable housing in Indiana. Also, disruptions in service as a result of the compressed timeline could delay progress on new construction and remodeling.

Response to Comment 55: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies and coal types, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA does not anticipate large impacts on the home construction industry, and is unable to see why the rule would impact availability of affordable housing since electricity prices are projected to increase only modestly.

Comment 56: Commenter 17805 has concerns about the potential economic and reliability impacts of the proposed rule on customers in Montana and the Dakotas.

Response to Comment 56: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies and coal types, and is unlikely to lead to extensive substitution away from coal-fired generation. Thus reliability issues are not expected to be significant. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand.

Comment 57: Commenter 18907 reports that a provider in the midwest has announced the shutdown of up to 25% of its coal-fired generating capacity, which will increase electricity rates. This price increase will impact businesses and create problems with remaining competitive for manufacturers.

Response to Comment 57: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies and coal types, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, many announced coal retirements are due to reasons not related to EPA actions, such as low natural gas prices and lower electricity demand. These units are typically the oldest and least efficient units in the coal fleet.

Comment 58: Commenter 18933 states that textile production in North and South Carolina and Georgia will suffer from an estimated increase of 11.5%. This expense is likely to make the industry less competitive with foreign businesses.

Response to Comment 58: Retail electricity prices are projected to increase roughly 3.1% in 2015 nationwide, based on the agency's analysis contained in the RIA for the rule. This increase, while not trivial, is not expected to yield significant impacts to manufacturers. The EPA's analysis indicates that coal-fired generation will maintain its large share of generation. In addition, industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies and coal types, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate.

Comment 59: Commenter 18502 expresses concerns about the impact the proposed rule will have on Puerto Rico when the costs of compliance are passed on to consumers. The commenter points out that the impacts of the proposed rule on the local economy will limit the economic recovery and increase electricity costs that are already twice those of the continental U.S. The commenter estimates that 70% of the electricity on the island is oil-fired generation and 70-75% of the consumers' costs are for fuel, so the proposed rule will strongly impact the system reliability and costs, despite having little benefit to an island with trade winds that produce excellent air quality. The commenter asks that the EPA reconsider controlling emissions from oil-fired units since the HAP emissions are much lower than from coal-fired units and the compliance costs are much higher.

Response to Comment 59: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies and coal types, and is unlikely to lead to extensive substitution away from coal-fired generation. In addition, separate standards are being finalized for non-continental oil-fired EGUs (see preamble).

Comment 60: Commenter 18538 states that the Texas economy and service reliability will be impacted by the proposed new rule. The commenter believes the proposed rule will negatively impact residential customers and energy-intensive business and the jobs they create. The commenter points out that environmental regulations in Europe have sent manufacturing businesses elsewhere. Commenters 18538 and 13526 state that because Texas generates more energy from coal than any other state (more than 60% greater than the next highest state) and almost 10% of the total amount for the U.S., the state's generation fleet will be disproportionately impacted and a large amount of retirements will occur, and the future of planned plants is in question. Commenters cite various studies and power plant closing announcements which show the likely retirement rate to be far beyond that estimated by the EPA. All of this makes reliability an issue in the state, with one study estimating a reserve margin of -8.6%. The commenter states that the EPA's impacts analyses are flawed and asks that they be revised to consider the full impact of all the new and proposed rules.

Response to Comment 60: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis includes the specific operating parameters and variability of other technologies and coal types, and is unlikely to lead to extensive substitution away from coal-fired generation. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 61: Commenter 18538 states that a competitive market will affect decisions about retrofitting or retirement of a plant. The commenter explains that a merchant generator selling into a competitive market, like that in ERCOT bears the cost and risk of the investment because there is no guarantee of recovering the costs to retrofit.

Response to Comment 61: The requirements of the CAA do not distinguish between energy markets, and participants in competitive markets understand the risks inherent in those markets, such as the potential costs associated with pollution controls. In addition, these markets are largely driven by the cost of the marginal producing electricity generating unit(s), which is most often natural gas. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate, irrespective of whether it is located in cost of service or competitive markets.

Comment 62: Commenter 18538 considers the EPA's predictions about energy efficiency mitigating impacts of the proposed rule and explains that Texas has a robust efficiency program, but estimates it will only offset 681 MW of demand in 2015 and 1,448 MW in 2020, a total of 1% in 2015 and 2% in 2020.

Response to Comment 62: The EPA believes energy efficiency measures can be a complement to this rule, and can be an important tool in helping address emissions. The EPA has not included all the likely additional energy efficiency measures that are likely to occur by 2015, but will continue to pursue energy efficiency improvements throughout the economy, along with other federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements.

Comment 63: Commenters 17137 and 18021 believe that if the proposed rule is implemented with the current timeline and stringency, industry in the southeast, which relies on affordable, reliable electricity, will be weakened, jobs will be lost, and power consumers will be hurt. Commenters point out that the southeast is particularly vulnerable to the proposed rule because it relies heavily on manufacturing and provides hundreds of thousands of jobs and billions in economic impact as a result. Commenters state that the abundant, reliable and inexpensive electricity from native coal resources is a factor in the thriving skilled labor market and foreign manufacturing investment. Commenter 18021 points out that regulated utilities have no choice but to pass cost increases on to customers. The commenter also explains that in addition to capital costs, the addition of control technology reduces efficiency of the plants, increasing fuel costs.

Response to Comment 63: The implementation date for this rule is set to be consistent with the requirements of the CAA for standards such as these. Retail electricity prices are projected to increase roughly 3.1% in 2015 nationwide, based on the agency's analysis contained in the RIA for the rule. This increase, while not trivial, is not expected to yield significant impacts to manufacturers. The EPA's analysis indicates that coal-fired generation will maintain its large share of generation. In addition, industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate.

Comment 64: Commenters 17712 and 17743 explain that cooperative EGUs will generally need to add controls to comply with the proposed rule, and others will need to shut down because they will be unable to comply in a cost-effective and timely manner.

Response to Comment 64: The EPA will work with relevant authorities to ensure a smooth transition with this rule. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). The EPA analysis also indicates that there will be relatively modest amounts of retirements and installation of pollution controls will be a cost-effective compliance measure. In addition, many coal facilities have already invested in pollution controls, and they are well positioned to comply with this rule with modest changes to operations.

Comment 65: Commenter 17718 considers the proposed rule to be hardest on states which rely heavily on coal-fired plants and uses Kentucky as a state which is jeopardized by the proposed rule due to the loss of inexpensive electricity giving it a competitive advantage at attracting industry. Kentucky runs the risk of seeing lucrative local businesses such as auto plants leave the region if electricity prices increase due to the proposed rule.

Response to Comment 65: The EPA's analysis indicates that coal-fired generation will maintain its large share of generation. In addition, industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate.

Comment 66: Commenter 17055 mentions that their initial assessment did not consider impacts the RICE regulations may have on the potential loss of small units relied upon by many municipalities. Elimination of these units could, the commenter believes, lead to local congestion and require transmission expansion and local programs to meet demand. The commenter believes that working with the industry to institute these changes will help preserve reliable system operations and also allow for a more gradual integration of the costs of compliance that could significantly mitigate reliability issues and sudden increases in consumer electricity prices.

Response to Comment 66: The agency is currently reconsidering the Compression Ignition and Spark Ignition RICE NESHAP. The outcome of this reconsideration may affect the congestion and other issues the commenter points out.

Comment 67: Commenter 17821 explains the additional hardships for small cooperative utilities, which often share several small units in order to split the risk and increase reliability. The commenter believes the EPA has not fully recognized the impact of the proposed rule on these small entities. The commenter does not believe that the work practice standards, subcategorization, health-based compliance options or emissions averaging will adequately reduce the burden to such organizations and their financial well-being will be strained by the proposed rule. The commenter believes more flexibility is needed, as well as more time, to minimize risk to small businesses.

Response to Comment 67: The EPA will work with relevant authorities to ensure a smooth transition with this rule. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). The EPA analysis also indicates that there will be relatively modest amounts of retirements and installation of pollution controls will be a cost-effective compliance measure. In addition, many coal facilities have already invested in pollution controls, and they are well positioned to comply with this rule with modest changes to operations.

Comment 68: Commenter 17745 expresses concern over the impacts on the Georgia state economy by the proposed rule, especially the increased cost of electricity and the impacts on residents and businesses.

Response to Comment 68: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. The EPA will work with relevant authorities to ensure a smooth transition with this rule. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). Although certain regions will need to do more in order to comply, those same regions will also benefit from the emission reductions. Overall, coal use is not anticipated to be greatly impacted as coal-fired sources install pollution controls, with only modest amounts of retirements. Retail electricity prices are projected to increase slightly on average by 2015. Thus, there may be some negative impacts from this rule in these regions, but these same regions will also experience some of the benefits, such as reduced premature mortality from less exposure to $PM_{2.5}$ emissions as shown in Appendix C of the RIA. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 69: Multiple commenters (16705, 17400, 17697, 17868, 18038, 18433) consider the EPA's RIA to be flawed in suggesting that only 97 municipal utilities will face a compliance cost of $666.30 million annually. Commenter 16705 states that these costs underestimate the impact on states such as Indiana, Ohio, Wisconsin, Michigan, Minnesota, Kentucky, Georgia, Alabama and Texas. Commenter 17400 notes that these costs ignore Guam, where an additional $49 to $103 million is expected to be spent in capital costs with $1.2 to $2.6 million in annual costs. Commenter 17697 explains that the cost analysis does not include the cost of purchasing power during scheduled outages for retrofit, the costs of fuel switching, or the inability to sell coal ash or coal combustion residuals to the cement industry. Footnotes pertaining to the coal ash include a reference and an estimate that fly ash would cost an extra $100 million over 20 years for disposal.

Response to Comment 69: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The EPA has also updated its UMRA analysis. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. The EPA will work with relevant authorities to ensure a smooth transition with this rule. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). There are also separate standards for non-continental liquid oil-fired EGUs. The EPA is addressing coal combustion residuals in a separate rulemaking.

Comment 70: Several commenters (17689, 17697, 17710, 18433) explain Guam's dependence on a single fuel-oil electric utility plant to provide all of the island's power. This situation leads the commenters to believe the island will be significantly impacted in energy costs and reliability as a result of the proposed rule. Commenters 17710 and 18433 state the rule's burden is unacceptable and that the cost of energy is a more significant part of household and business expense than nationally. Commenter 17698 requests that acid gases not be regulated under the proposed rule, since it will increase costs and make compliance more difficult. Commenters 17697 and 18433 believe the electricity rates will increase, especially since 70% of the cost of Guam's power production comes from fuel costs. The commenters believe this rate increase will increase unemployment and cause economic hardship for the already disproportionately high percentage of the island's population currently unemployed or underemployed.

Response to Comment 70: The EPA is required to regulate acid gas HAP such as hydrochloric and hydrofluoric acids under this rule, as explained elsewhere in the final rule record. As to impacts to Guam, the agency will limit the impact of this rule on the power plant to that consistent with the CAA and note that in the final rule, we have established a subcategory for non-continental liquid oil-fired EGUs that should address some of commenters' concerns.

Comment 71: Commenter 17730 estimates that the proposed rule will cost hundreds of millions of dollars in initial capital costs for their region, which will be passed on to consumers in some of the top 100 poorest counties in the country.

Response to Comment 71: The agency's analysis of changes in the national average retail electricity price associated with this rule finds is projected to be 3.1% in 2015. If this increase in retail electricity price is a concern, then state and local agencies are best equipped to manage rate structures to mitigate any impacts associated with this increase. In addition, the increase in retail electricity price should be understood in light of the substantial benefits (including co-benefits).

Comment 72: Commenter 17791 requests that the EPA avoid compromising energy system reliability, seek ways to minimize cost impacts, ensure availability of electricity and natural gas, consider cumulative impacts of multiple rules and employ rigorous cost-benefit analyses. The commenter also suggests the EPA consider regional differences that will impact system reliability and costs, such as the increased impacts on regions relying heavily on coal and oil and encourages cooperation between the EPA and state and federal energy and environmental regulators.

Response to Comment 72: The agency has studied possible impacts on reliability as a result of this rule, and has determined that these impacts should not be significant. The agency has prepared a detailed TSD to document this study, and this document is the docket for this rulemaking. The agency has considered impacts on a regional basis as part of its overall analyses done using the IPM; these results are documented in the RIA for the rule and in several TSDs.

Comment 73: Commenter 18497 says the group's six "footprint states" generated over 67% of their electricity from coal in 2009, varying from 36.5% in Virginia to 96.2% in West Virginia. The commenter says the variability of the impacts will be similar and should be considered by the EPA. Based on age alone, the commenter states that over 28% of the region's summer generating capacity (143 units) can be considered at risk for retirement due to the proposed rule.

Response to Comment 73: The EPA has conducted detailed impact analysis of the rule, which shows that coal will remain the largest source of electricity. The agency has estimated that less than 2% of all coal-fired generating capacity may be uneconomic to maintain and removed form operation by 2015 in response to the rule, and this result is the product of business decisions rather than a specific requirement of the rule. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand and also manage the installation of pollution controls. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 74: Commenter 17829 explains that their power supplier estimated that if scrubbers are required for their plant, the cost could reach $1 billion. The commenter goes on to state that the resulting cost increase will most impact the elderly, poor and those who have lost jobs at a time when the Low Income Home Energy Assistance Program has been decreased significantly.

Response to Comment 74: The rule does not dictate any particular technology and the EPA has attempted to provide the maximum degree of flexibility to source owners within the limitations of the CAA. The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis indicates that coal will remain the largest source of electricity. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand and also manage the installation of pollution controls. The EPA will work with relevant authorities to ensure a smooth transition with this rule. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 75: Commenter 17884 quotes NMA statistics showing coal is responsible for $65.738 billion in annual economic activity, produces 1,798,800 jobs and $36.345 billion in annual labor income. The commenter reports that regions such as Appalachia, the midwest and Rocky Mountain west will be significantly affected by the rule, including increased unemployment.

Response to Comment 75: The agency's analysis as found in the RIA shows that the overall impact of the rule to be relatively small, in the context of the entire power sector. Although certain regions will need to do more in order to comply, those same regions will also benefit from the emission reductions. Overall, coal use is not anticipated to be greatly impacted as coal-fired sources install pollution controls, with only modest amounts of retirements. Retail electricity prices are projected to increase slightly on average by 2015. Thus, there may be some negative impacts from this rule in these regions, but these same regions will also experience some of the benefits, such as reduced premature mortality from less exposure to $PM_{2.5}$ emissions as shown in Appendix C of the RIA. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 76: Commenters 17901 and 18023 state that communities near existing coal-fired generation units will be especially hard-hit if the plants are permanently retired. The communities will suffer from job loss and diminished tax revenue.

Response to Comment 76: Although it is possible that there may be some negative local economic impacts associated with this rule, impacts such as retail electricity price increases should be modest. Also, the estimated number of early retirements according to the agency that may result from this rule is 4.7 GW in 2015, or about 2% of all U.S. coal-fired capacity in that year. Overall, coal use is not anticipated to be greatly impacted as coal-fired sources install pollution controls, with only modest amounts of retirements. These results are presented in the RIA for the rule. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. Although certain regions will need to do more in order to comply, those same regions will also benefit from the emission reductions such as through reduced premature mortality from less exposure to $PM_{2.5}$ emissions as shown in Appendix C of the RIA.

Comment 77: Several commenters (18422, 18433, 18575) request that the EPA reconsider the regulating of acid gases as they are not required and will impose greater cost and difficulty. The commenters ask that the rule be reevaluated to be more realistic and cost-effective.

Response to Comment 77: The agency believes the regulation of acid gases that are HAP is both required and appropriate under this rule. The preamble to this rule provides the rationale for this position.

Comment 78: Commenter 18447 disagrees with the EPA's assessment that the reductions can be achieved without significantly affecting availability or cost of electricity and with an increase in jobs. The commenter expects job losses from the proposed rule and explains that the City of Ames, Iowa has one base load plant and two diesel combustion turbine "peakers" and cannot shift power away from older units to newer plants. The commenter explains that while switching to natural gas may seem like the preferred compliance option, there is not enough of a natural gas supply to support the needed generation. Also, the city's power plant provides disposal for all municipal solid waste for the city and a neighboring town and the units would not be able to burn the refuse-derived fuel if it converted to natural gas. Thus, a fuel switch would lead to a dilemma for disposal of solid waste.

Response to Comment 78: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis indicates that coal will remain the largest source of electricity. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 79: Commenter 17648 offers projections showing that 2015 electricity prices in most areas will be the same or lower than they were in 2010 as a result of the proposed rule. The commenter retained NorthBridge Group to estimate the potential rate impact resulting from the proposed rule on its customers in both the ComEd and PECO service territories. NorthBridge concluded that, based on current market conditions, generation rates in 2015 will be less than 2010 levels on an inflation-adjusted basis. NorthBridge reports that this finding is in partly due to the decline in natural gas prices in recent years. Exelon's customers will benefit from lower gas prices, and this price decline will mitigate any potential rate increases related to the Toxics Rule. The results of NorthBridge's analysis are set forth in Figure 1 (See 17648-A2_Figure 1_ComEd and PECO Generation Rates.docx).

Response to Comment 79: The Commenter's statements are not inconsistent with the results of EPA's analysis, which indicates that impacts on retail electricity and natural gas prices of the rule will be reasonable in light of the large benefits.

Comment 80: Commenter 17676 offers suggestions of things consumers and regulators can do to mitigate the impact of increasing electricity costs.

1. The commenter discusses the establishment of centralized entities that provide revenue for power plants to provide power to the grid when necessary, called "capacity markets." The commenter suggests that capacity markets need more oversight to ensure newer, more advanced facilities take precedence over less efficient plants because Synapse Energy Economics states that capacity markets keep electricity prices high and less efficient plants operating.
2. The commenter also suggests pushing FERC to be more proactive about market violations by encouraging competitive regional markets with balanced rules, monitoring such markets for anticompetitive behavior and enforce market rules.
3. The commenter also suggests better energy efficiency programs for domestic and imported electric products and better building codes to decrease energy demand can save consumers money and limit the amount of pollution released by EGUs.

Response to Comment 80: We thank the commenter for these suggestions. The agency has worked with FERC and other Federal agencies to examine ways of mitigating potential negative consequences associated with this rule. The EPA believes that there are many approaches that can help mitigate price increases, and is a strong supporter of energy efficiency measures. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures.

Comment 81: Several commenters (17682, 17884, 18033, 18484, 18023) consider the proposed rule to be a tax on the American public, since utilities implementing upgrades will pass the costs on to the consumer. Commenter 17682 questions the preference of Americans to subsidize renewable energy sources and put money into the proposed rule instead of other environmental programs with greater benefits. Commenters 17884 and 18484 explain that the tax-like price increase reduces income of energy consumers and depresses business development. The commenters used California as an example of a state that uses low rates of coal-based electricity and cite companies that have left the state as a result of substituting higher-cost forms of electricity for coal. Commenter 18033 states that coal-derived energy will rapidly become more expensive, especially in the "rust belt" and southeast region, as can be seen by the rate increase already requested in Louisville. Commenter 18023 believes the "indirect taxation" limits the ability of the economy to absorb the cost of retrofitting and new capacity projects, lowers discretionary spending lead to job losses and lost tax revenues, given the restrictive timeframe for compliance.

Response to Comment 81: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis indicates that coal will remain the largest source of electricity. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand and also manage the installation of pollution controls. Although electricity consumers will likely see a small price increase, it should be noted that these consumers will also experience the improvement in air quality from the reductions due to the rule, and the benefits of this improvement will greatly exceed costs. The price increases in electricity and natural gas should be considered in light of the substantial benefits offered by this rule. In addition, history has shown that the impact of EPA regulations is much lower than anticipated, and predictions of severe economic impact have been often repeated, but not realized.

Comment 82: Commenters 16705 and 18038 believe the proposed rule will have a significant impact on jobs in their community and increase the electric rate, driving out businesses.

Response to Comment 82: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis indicates that coal will remain the largest source of electricity. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 83: Commenters 16856 and 18038 believe the proposed rule will severely impact the economy of the coal-producing states and utilities that provide almost 50% of their electricity from coal. Commenters ask that the EPA bring jobs back to the U.S. and stop sending manufacturing jobs to countries where environmental impacts are not considered.

Response to Comment 83: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis indicates that coal will remain the largest source of electricity. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 84: Commenter 17627 considers the EPA's RIA document to be lacking in local economic impacts associated with reduced operations or plant closures.

Response to Comment 84: The EPA has conducted detailed impact analysis of the rule, which includes regional information and impacts, and more detail can be found in the corresponding IPM output files for the final rule, which has detail for the 32 power regions across the country. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 85: Commenter 17701 mentions that the proposed rule will have different reliability and cost effects on different regions of the country due to differing resources, transmission and capacity, market structures, approaches to energy efficiency, transmission options, electricity demand projections and consumer concerns.

Response to Comment 85: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The analysis provides a rich characterization of regional issues, and reflects the differences in the power sector composition across those regions. The impact of the rule will vary across regions, and the EPA has presented some of those impacts in the RIA.

Comment 86: Commenter 18030 quotes the NERA study could cost Michigan 40,000 jobs and increase electricity prices by 20.5% in 2016 and likely lead to the closing of numerous Michigan plants. The commenter requests the implementation of the proposed rule be suspended.

Response to Comment 86: The EPA has designed a rule that is intended to offer flexibility, to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA. History has shown that industry adapts to regulations and finds more cost-effective compliance approaches that the EPA can anticipate or predict, thus lowering the actual cost of its rule relative to what the EPA initially projected. The EPA has conducted detailed economic impacts analysis on the regulated sector, and finds the impact of the rule on the regulated sector is small compared to the overall benefits, and the industry has an excellent track record of installing pollution controls without greatly impacting electricity prices. The report cited by the commenter is not transparent with regards to several key criteria, and it is thus impossible to fully assess the credibility of the results. It has often been claimed that regulations do harm to the economy and jobs, but the evidence is weak or nonexistent, while there is a large body of literature that shows overall, the impacts of regulations on jobs and the economy is very small.

Comment 87: Several commenters (17705, 17732, 18540) discuss the unique situation of the Navajo Generating Station (NGS), which plays a key role in water delivery to Native American communities, farmers and cities in Arizona and which provides critical energy to the region. The plant also provides good jobs to 540 skilled workers and provides economic support for several communities through tax payments and other jobs. The plant also helps the U.S. meet its federal trust responsibilities under the 2004 Arizona Water Settlements Act, and provides power and funding for the Central Arizona Project (CAP). The commenter states that the IPM model defines the plant as uneconomic to maintain, but given the importance of the facility, the owners want to work with the EPA to retain the plant. The commenter believes the NGS should not have to install a baghouse to comply with the proposed rule and asks that the EPA evaluate all impacts of closure on the Navajo Nation on a regional economic basis, rather than on a Nation-wide basis. Commenter 18017 agrees with these comments and expresses concern about the closing of NGS affecting many entities, if sufficient time isn't given for compliance. The commenter details the difficulties to this region of Arizona would have in finding alternative power sources for electricity use and to pump water. The commenter estimates pumping costs could go up 50-300% by 2017. Commenter 18540 explains that it receives its entire water supply through the CAP system and is concerned with the effect of the proposed rule on the viability of the CAP. The commenter stresses the fact that the U.S. government owes a trust responsibility to commenter and other Indian tribes, including water rights. The commenter explains that it gave up its right to assert water claims held from "time immemorial" in return for specific provisions by the U.S. government of water from the CAP and Yuma-Mesa Division of the Gila project. The commenter explains the various water settlement legislation in place and urges the EPA to carefully consider the possible effects of its proposed rulemaking on the continuing viability of the CAP system and requests that the EPA consult with it and other tribes that may be affected by the proposed rule, pursuant to the Agency's May 2011 Consultation Policies.

Comment 88: Commenters 17732 and 18017 report that the power plant associated with the Navajo Nation (FCPP) employs nearly 600 people, most of them Navajo Nation members. The commenter goes on to explain that the Navajo Mine provided $69 million into the Navajo Nation's revenue in 2007 and employs 427 people, 87% of whom are Navajo tribal members. The Peabody Kayenta Mine employs another 400 workers, many of whom are Native American. Revenue from the power plants and mines that supply them make up 1/3 of the general operating budget of the Navajo Nation, which employs another 7,316 people, 98% of whom are Navajo. The Hopi tribe estimates that revenues derived from the plants and mines make up 88% of their tribe's operating budget. Details of this revenue and supporting numbers may be found at: http://www.navajobusiness.com/pdflCEDS/CED NN Final_09_10.pdf.

Comment 89: Commenter 17732 describes the impact of EPA regulation shutting down the Mohave Generating Station, which led to the closing of the Black Mesa Mine. The commenter explains that 160 people were put out of work at the mine, and Navajo Nation's general revenue was decreased by 30%. The commenter states that if the proposed regulations lead to a shutdown of the remaining two power plants due to cost-prohibitive emission controls, the mines supplying them would also close. These closures would lead to revenue and job losses so extreme they would impugn the solvency of the Navajo Nation government. The commenter states that the EPA failed to analyze the impacts to the Navajo Nation as part of the impact analysis. The commenter points out that unemployment is over 50% among the Navajo people, and no skilled labor force or industry exists in the pollution control technology field among their population. Therefore, the new jobs expected to be created by the proposed rule would not help the Navajo Nation, but the closing of the coal and power industry would lead to the loss of 31,000 jobs. This would force migration of many workers, a "social cost" not analyzed by the EPA.

Comment 90: Commenter 19214 requests that the Table 8.8 showing that NGS will be likely to shut down by 2015 be changed to show continued operation of this important coal-fired plant. The owners acknowledge that the rule will be challenging, but are committed to working with the EPA to keep this critical resource open.

Response to Comments 87 - 90: The EPA modeling and projections are intended to be a reflection of possible compliance using specific tools, assumptions, and methodologies that the agency believes to reflect the best and most current information related to the power sector. It is not intended to reflect actual compliance decisions, since those will be made individually by the affected industry based on what makes most sense using existing technologies or other, more cost-effective strategies. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues as they arise. Public utility commissions and other authorities, such as tribes, will need to develop and implement compliance plans in order to address harmful emissions.

Comment 91: Commenters 17807 and 17901 expresses concern about economic impacts to residential and commercial customers, particularly minorities, the elderly and economically disadvantaged customers.

Response to Comment 91: The EPA has conducted detailed impact analysis of the rule, which shows reasonable impacts to retail electricity prices. The average impact on household energy expenditures (electricity and gas) is anticipated to be less than $3 per month.

Comment 92: Commenter 17813 questions the results of the IPM model because it shows a heat input of 25.353 TBtu for their facility, while average from 2006-2010 is 35.285 TBtu. Because of this discrepancy, the commenter questions the assumption that the plant will retire.

Response to Comment 92: The EPA modeling and projections are intended to be a reflection of possible compliance using specific tools, assumptions, and methodologies that the agency believes to reflect the best and most current information related to the power sector. It is not intended to reflect actual compliance or retirement decisions, since those will be made individually by the affected industry based on what makes most sense using existing technologies or other, more cost-effective strategies.

Comment 93: Commenter 17815 reports that in 2010, coal-fueled generation provided approximately 40% of electricity in the Electric Reliability Council of Texas region and provided over 33,000 permanent jobs as well as $10 billion in annual expenditures. The commenter says that the average income for a lignite mining employee in Texas is 2.14 times the state average income for all industries and has a tax contribution of $1.012 billion.

Response to Comment 93: The EPA has conducted detailed impact analysis of the rule, which provides a rich characterization of regional issues, and reflects the differences in the power sector composition across those regions. The impact of the rule will vary across regions, and the EPA has presented some of those impacts in the RIA. Overall, coal-fired generation is not expected to change significantly since sources are anticipated to install pollution controls. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy

Comment 94: Commenter 17901 questions the benefits of the proposed rule in the face of job losses likely to hit coal-producing regions especially hard. Commenter 18500 agrees and points out that some regions will see almost no impact from the rules, such as the Pacific northwest while the midwest and other regions will face large cost increases.

Response to Comment 94: The EPA has conducted detailed impact analysis of the rule, which provides a rich characterization of regional issues, and reflects the differences in the power sector composition across those regions. The impact of the rule will vary across regions, and the EPA has presented some of those impacts in the RIA. Overall, coal-fired generation is not expected to change significantly since sources are anticipated to install pollution controls. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 95: Commenter 18430 cites a Unions for Jobs and the Environment (UJAE) study that estimated job losses due to the proposed rule to be over 250,000, with more than 11,000 in Virginia. The commenter states that the importance of the coal industry to Virginia makes that state especially painful.

Response to Comment 95: The EPA has conducted detailed impact analysis of the rule, which provides a rich characterization of regional issues, and reflects the differences in the power sector composition across those regions. The impact of the rule will vary across regions, and the EPA has presented some of those impacts in the RIA. Overall, coal-fired generation is not expected to change significantly since sources are anticipated to install pollution controls. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 96: Commenter 18477 believes that non-continental oil-fired EGUs should have a separate regulatory impact analysis. The commenter explains that non-continental utilities have fewer economic resources available to address proposed rule requirements and as regulated utilities they must obtain approval for rate increases to offset costs. Since non-continental electricity prices are already higher than on the continental U.S. the economic consequences associated with compliance are also higher.

Commenter 17760 states that the EPA should conduct a separate RIA for non-continental oil-fired EGUs. According to the commenter, in March 2011, the EPA released the RIA of the Proposed Toxics Rule: Final Report. The commenter states that the RIA utilized an Integrated Planning Model ("IPM") to predict the costs associated with the proposed rule, as well as its effect on the economy and public health. The commenter asserts that the RIA only addressed coal-fired EGUs; the EPA stated that it would address regulatory impacts related to liquid oil-fired units in the final rule. Of the 154 oil-fired EGUs identified in the proposed rule, 31 of the units are located on the islands of Oahu, Puerto Rico, and Guam. The commenter states that since the EPA intends to analyze regulatory impacts related to oil-fired units as part of the final rulemaking, the EPA should address non-continental liquid oil-fired units separately in that analysis.

Response to Comment 96: The final rule contains provisions that are specific to non-continental liquid oil-fired EGUs. See preamble for further discussion of the treatment of these sources.

3. Retiring coal-fired EGUs, shutdowns.

Comment 97: Commenter 17403 says that capital that will be deployed by EGU owners to implement emissions control measures under the proposed rule should create well-paying jobs for skilled workers across the country. However, the commenter goes on to say that premature shutdown of existing coal-fired EGUs will also result in an estimated 50,000 direct job losses in the coal, utility and rail industries with a total job loss including indirect jobs of 251,300. The commenter considers the costs and benefit analyses of the proposed rule to be incomplete and misleading and the proposed rule structured to avoid unnecessarily eliminating jobs.

Response to Comment 97: The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity). In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 98: Multiple commenters (17623, 17656, 17834, 17868, 17930, 18018, 18497, 18023) discussed predictions for the number of coal-fired EGUs that are likely to retire as a result of the proposed rule and Transport rule. Several commenters (17623, 17868, 18497, 18023) cite and provide references to seven studies predicting retirements of 5 to 65 GW in 2015, where six of the seven predict retirements of 35 GW or more. Commenter 17656 estimates that the proposed rule, when viewed in conjunction with the entire body of new regulatory initiatives on the utility fleet, will impact roughly 400,000 MW of oil- or coal-fired generation, or 40% of the current available capacity in the U.S. This commenter quotes NERC which predicts the rules could jeopardize 30 to 70 GW of generating capacity by 2015. Commenter 17834 predicts the early closure of many facilities as a result of the proposed rule and reports that these EGUs play a central role in a region's economy since they are a source of jobs and contribute to the tax base. Commenter 17868 believes that the EPA has grossly underestimated the number of coal-fired generation retirements at only 9.9 GW, which is only 3% of all coal-fired capacity by the year 2015. The commenter believes that the EPA chose to view the proposed EGU NESHAP in isolation and not in the CSPAR (the replacement of the Regional Transport Rule). Many published studies project retirements above 40 GW, when viewed in combination and under certain circumstances.

Commenter 18023 also quotes the NERC report and discusses the resulting problems from the predicted shut downs, which include adverse impacts of displacing coal-fired generation with other forms that do not provide the same kinds of grid support functionality, increased interconnection of variable energy sources such as solar and wind. The problem of grid operators being unable to know the locations and parameters of generator locations in enough time to facilitate transmission facilities is also mentioned, and Commenter 18023 requests a thorough reliability analysis given the compliance framework and timeline of the proposed rule.

Response to Comment 98: The agency prepared a resource adequacy analysis for the proposed rule and has revised that analysis for the final rule. The agency is working with FERC regarding the reliability impacts of this rule. The EPA estimates 4.7 GW of capacity will retire early as a result of this rule. We have not prepared a cumulative impacts analysis for the various power sector rules that have been finalized or are in process of being finalized because the agency does not believe such an analysis would be as accurate and transparent as analyses for each of these individual rules. The EPA has outlined the various flexibilities associated with the rule, and the approaches to reliability issues in the preamble.

Comment 99: Commenter 17648 discusses the economic factors behind EGU retirements. These factors include the cost of alternative generation using natural gas, the cost of implementing demand response measures that can be bid into capacity markets, and the cost of continuing to generate power from an existing unit. The commenter states that regardless of the costs associated with the Toxics Rule and other EPA electric power industry regulations, some power plants were already economically unsustainable. The commenter quotes M.J. Bradley, who points out, "Of the 122 coal units in PJM with capacity less than or equal to 200 MW, 35 failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM . . . in addition to approximately 10 GW of coal generation that has or will be retired during the seven years from 2004 to 2011, another 11 GW faces a troubling economic outlook." The commenter provides confirmation of this by the most recent PJM capacity auction, where approximately 6.9 fewer GW of coal-fired capacity cleared the auction (1.85 fewer GW were offered) as compared with the prior year's auction, and an additional 4.836 GW of new demand response (energy efficiency) resources cleared the auction. Thus, the commenter states, some claims linking retirements to the Toxics Rule are overstated and misleading. The commenter gives the example of the American Electric Power attempt to link its planned plant closures to the Toxics Rule, but those plants already are slated to either close or to upgrade controls to comply with existing laws. The commenter goes on to quote three independent studies that support the finding that over 50% of the fleet is equipped with scrubbers and the number will increase to nearly 2/3 by 2015. (Footnotes in comment provide references to the studies and further quotes.)

Response to Comment 99: As discussed elsewhere in this document and in the preamble to this rule, the EPA believes there will be modest levels of coal retirements, and many units slated for retirement are being taken offline for other reasons aside from requirements to reduce emissions.

Comment 100: Commenters 17812 and 17736 believe the proposed rule will adversely affect the cost-effective operation of industry energy operations and quote the U.S. Chamber of Commerce testimony before Congress: "American Electric Power Co. made headlines last month when it disclosed that EPA's “train wreck: of coal regulations – Coal Ash, Utility MACT, the Transport Rule and Cooling Water Intake Structures – would force the utility to retire 6,000 megawatts of coal-fired generating capacity and spend another $6 billion to $8 billion reworking the rest of its fleet.” AEP would close three power plants in West Virginia, one in Ohio and one in Virginia, and would retire several boilers at coal plants in Indiana, Kentucky, Ohio, Texas and Virginia.

AEP is not alone. Six other power plants have announced early retirement due to excessive regulation: Portland Gas & Electric’s Boardman coal-fired power plant in Oregon; Exelon Corporation’s Oyster Creek Nuclear Generating Station in New Jersey; TransAlta Corporation’s Centralia coal-fired power plant in Washington; and, just this week, three Georgia Power plants in the next 2 years. In each case, the utility was forced to choose between installing several hundred million dollars’ worth of pollution controls to comply with the EPA regulations, or simply shut down early. In all cases, the utility chose early retirement.”

Commenter 17812 also expresses concern that increasing energy costs will reduce the ability of U.S. industry to compete in the global marketplace, expand in the U.S., create jobs and increase contribution to the GDP. The commenter quoted the 2010 EIA outlook which showed a 9.1% decline in industrial electricity demand, the lowest since 1987.

Response to Comment 100: As discussed elsewhere in this document and in the preamble to this rule, the EPA believes there will be modest levels of coal retirements, and many units slated for retirement are being taken offline for other reasons aside from requirements to reduce emissions.

Comment 101: Several commenters (17682, 17813, 17904, 17930) mention the proposed rule’s impact on mining. Commenter 17682 mentions increasing energy costs for the U.S. mining industry resulting in fewer projects and associated jobs, as well as increasing dependence on foreign mineral resources. Commenters 17904 and 17930 see mining impacts being disproportionally large for lignite mines, which are dependent on their co-located lignite-fired power plants. Commenters state that if the plant closes, there is no market for the lignite and the mine will also close, displacing plant workers. These impacts are largest in Texas, the largest coal consuming state and fifth largest coal producing state, as well as a deregulated electricity market. Commenter 17904 points out that the Texas coal market provided a buffer against natural gas price volatility and in particular believes the proposed rule does not take into account the emission reductions already achieved by industry in general and their company in particular. Commenter 17813 states that impacts will be magnified in Texas, since it is the largest coal consuming state and mines lignite. Commenter 17813 also states it is unclear the extent to which the EPA includes the impacts on the mining industry that will result from this rule.

Response to Comment 101: The agency presents impacts on the coal mining sector from this rule in the RIA. Given the modest increase in coal and other energy costs associated with the rule, the agency does not expect widespread impacts on coal mining. The agency’s modeling accounts for all emission controls and programs installed and/or implemented up through December 2010. The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity). In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 102: Commenter 18500 states that the EPA has justified the regulation of EGUs based, in part, on the fact that such regulation will make the market for electricity more level and less skewed toward polluting units. Although there is no legal basis to justify regulation on market parity, the EPA must recognize that by changing market dynamics in single clearing price markets, every incremental increase in price applies to all electricity sold in that market, not just to the impacted unit. Given that half of the American population lives in Regional Transmission Organizations (RTOs) where incremental cost increases apply to all energy costs, this will be a significant factor. The EPA has failed to account for the impact these rules will have on the total cost of energy across RTO markets where every incremental increase in price applies to all electricity sold in that market, not just to the impacted unit, while at the same time asserting beneficial market impacts.

Commenter 17868 asks that the EPA address the unproductive costs of compliance that occur due to RTO market structures, since the rule is expected to lead to plant closures of plants dispatched to meet demand. As a result, power generated by plants not facing greater compliance costs will still be sold at a price reflecting the costs to other plants. This occurs because the highest offer accepted in an hour sets the price for all megawatt-hours consumed, a single coal or natural gas plant can affect the prices paid for by all the electricity generated by nuclear, hydropower, wind, and all other plants within that hour. The commenter believes this market structure will lead to costs beyond that of compliance being passed on to consumers and gives the following example: "in the most recent Reliability Pricing Model (or RPM) auction, held in May 2011 to procure capacity for the June 2014 through May 2015 time period, a number of plants added to their supply offers the costs associated with installation of emission control technologies to meet environmental regulations. PJM estimated that these higher costs were responsible for at least half of the 350% price increase between the past two auctions in the western region of PJM, from $27.73 per MW/day to $125.99 per MW/day. Although the number of units or MWs that included these compliance costs is not yet available, PJM's graphical representation shows that of the roughly 150,000 MW that cleared the auction and will receive this capacity price, about 120,000 MW offered to sell capacity at a zero or close to zero price. (Zero price offers are typically submitted by existing base load plants who are price takers in the auction.) Therefore the half of the $98 price increase attributable to environmental upgrades will be paid to all 120,000 MWs of capacity that did not include environmental compliance costs in their offers, equal to an unproductive cost of at least $2.1 billion for just one year…These factual PJM auction results from May 2011 demonstrate that the U.S. EPA's assertion that the electricity consumer will see no more than a 3.6% increase in the cost of electricity does not match recent actual market performance. The U. S. Census reports that currently there are 307,006,550 people in the U.S. and approximately 51 million of them live in the PJM Market. This means that approximately 15% of the U.S. population is affected by PJM Market" The commenter provides figures showing how coal plant closures will impact different locations. (EPA-HQ-OAR-2009-0234-17868-A2)

Response to Comment 102: The EPA provides regional estimates of the projected retail electricity price impacts of the rule, and the impacts vary across regions for a variety of reasons (market structure being one of them). In addition, the auction results cited are not a reflection of retail price impacts, which will be dampened since the cost of generation is just one of several components of retail prices. The auction also resulted in significant new capacity and additional demand-side resources, which show that there are multiple avenues for how utilities can respond to the requirements of this rule. The auction also indicates that there will be adequate reserve margin. The most important point that the commenter ignores is the baseline. The EPA assesses the impacts of its rules not in relation to what is happening today or from the 2013/2014 PJM auction, but in relation to what would have happened in the absence of this rule in the same year (in 2015 for MATS). The commenter is unable to fully ascertain, based on the analysis presented, the incremental effect of the rule *alone* and is lumping in other important industry trends and dynamics that will impact future prices. The EPA has updated its analysis of price impacts of MATS, which are presented in the RIA on a regional and nationwide basis.

Comment 103: Commenter 18497 explains that the EPA's retirement estimate is very low and cites several studies of regional retirements. The commenter reports that in the East North Central U.S. Census Region alone (includes the states of Indiana, Illinois, Michigan, Ohio, and Wisconsin), ICF identified 25 GW of at-risk capacity- more than in all other census regions combined and over two times the next most impacted region (East South Central - 11 GW). The Brattle Group analysis estimated 50-65 GW of coal-unit retirements nationwide by 2020 based on the need to install scrubbers and SCR controls. Of that total, 12-15 GW were located in the Midwest Independent Transmission System Operator (MISO) regional transmission organization (RTO), and 8-15 GW were located in the PJM Interconnection (PJM). The commenter references the DOE deputy assistant secretary for clean coal, James F. Wood who states, "Number one, electric rates are going to go up. Number two, whether or not construction jobs in the green industry are created, I think there's [sic] virtually no manufacturing jobs that are likely to be created from the replacement of coal. Three ... transmission grid stability is likely to emerge as a major issue, both because of the shutdowns and because of the intermittency of renewables." He also pointed out the sizable impact shutting down one power plant could have on the local community. The commenter also quotes the Credit Suisse analyses showing around 60 GW of coal closed in 2013-2017 and 100 GW requiring large investments to comply at a cost of $70-100 billion to cover compliance or replacement expenses. The commenter also quoted the Berstein report which projected 54 GW of coal retirements and a 1.2 Tcf increase in annual natural gas demand, leading to increased prices as much as $92/MW a day.

Response to Comment 103: The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) as a result of this rule. Most studies use flawed assumptions and do not fully reflect the rule, including some important areas of flexibility. The analyses also conflate other issues, like natural gas prices and low electricity demand, and do not isolate the effect of this rule separately. The EPA believes there will be modest levels of coal retirements, and many units slated for retirement are being taken offline for other reasons aside from requirements to reduce emissions. The impact of the rule will vary across regions, and the EPA has presented some of those impacts in the RIA. Overall, coal-fired generation is not expected to change significantly since sources are anticipated to install pollution controls. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 104: Commenter 16469 states that the coal units more likely to retire due to the proposed rule are over 40 years old, under 400 MW and are cycling or "load-following" units for which the costs associated with additional controls would be too high for the infrequently run units to recoup. The commenter expects combined cycle natural gas units to pick up the share of generation for these units.

Response to Comment 104: The EPA agrees with the commenter.

Comment 105: Commenter 17881 explains the process by which the regulated utility created a Strategic Plan with the state and the EPA which commits them to a $1.6 billion upgrade through the year 2018. The commenter reports that they now find themselves in a position where they will need to retire a significant percentage of their coal-fired fleet in response to the proposed rule.

Response to Comment 105: Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 106: Commenter 16849 reports that they plan to convert a Riverton, Kansas plant to use natural gas, rather than retiring it, as predicted in the "IPM Parsed Results Policy Case."

Response to Comment 106: The EPA modeling and projections are intended to be a reflection of possible compliance using specific tools, assumptions, and methodologies that the agency believes to reflect the best and most current information related to the power sector. It is not intended to reflect actual compliance decisions, since those will be made individually by the affected industry based on what makes the most sense to them using existing technologies or other, more cost-effective strategies.

Comment 107: Commenter 17403 believes the EPA has not adequately assessed the costs associated with the retirement of smaller units, just as job losses and employment shifts as workers are retrained and re-employed elsewhere.

Response to Comment 107: The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 108: Commenters 17901 and 19742 believe the proposed rule and other federal rulemakings will force the premature shutdown of many coal-fired power units, resulting in the loss of thousands of jobs in utilities, coal, manufacturing and transportation. Commenter 17901 notes that states such as Ohio that rely on eastern bituminous coal will be especially hard-hit.

Response to Comment 108: The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) resulting from this rule and coal-fired generation will not change significantly. The EPA questions whether any units will be retired "prematurely," noting that any retirements likely to result from the rule will be of the oldest units that owners find least economically viable to control. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 109: Commenter 17931 disagrees with the EPA's conclusion that few coal-fired units will retire in response to the proposed rule because they state that DSI use will not provide the expected compliance.

Response to Comment 109: There are many compliance options, and each affected source will choose the most effective strategy to meet the requirements of the rule. The EPA is not prescribing particular technologies, and industry has a successful track record of responding to air reduction programs through innovation, often a cost much less than what the EPA originally anticipated.

Comment 110: Commenter 16850 notes that significant controls would be necessary at many of Florida's coal- and oil-fired generating units, and some units would be at risk of retirement. Commenter 16850 states that the EPA's final rules should avoid compromising electric system reliability and allow the maximum compliance flexibility for electric utilities provided for under the Clean Air Act.

Response to Comment 110: As stated above, there are many compliance options, and each affected source will choose the most effective strategy to meet the requirements of the rule. The agency prepared a resource adequacy analysis for the proposed rule and has revised that analysis for the final rule. The agency is working with FERC regarding the reliability impacts of this rule. The EPA has outlined the various flexibilities associated with the rule, and the approaches to reliability issues in the preamble. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 111: Commenter 18016 predicts an 8% decrease in coal production in Alabama as a result of the proposed rule, exacerbating economic problems there. Another concern to the commenter is the cost increases and capacity shortfalls resulting from the expedited shutdown of tens of thousands of megawatts of existing coal-fired generating capacity.

Response to Comment 111: The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) and coal-fired generation will not change significantly. The agency has also assessed resource adequacy, and has determined that there is sufficient excess capacity in existence that will help serve load. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 112: Commenter 18424 states that according to a study by UJAE, more than 60% of coal shipments in Indiana would not be able to comply with that limit when burned in units controlled by scrubbers operating at 95% SO_2 removal efficiency. If sources cannot comply with the proposed limits using bituminous coals, they will not use those fuels or they will retire the units.

Response to Comment 112: : The EPA disagrees with the comment. Since scrubbers effectively capture acid gas HAP more efficiently than SO_2, units equipped with this control device operating at 95% SO_2 removal efficiency are expected to suffice.[72] For those scrubbers operating below 95% SO_2 capture, controls upgrades are available to improve performance.[73] Potential impacts to coal supply are discussed in the preamble for the final rule and in the RIA.

Comment 113: Commenter 17852 asserts that the proposed rule can and should promote the orderly retirement of old, high-emitting power plants. It is widely recognized that the current fleet of coal-fired power plants includes many old, uncontrolled, inefficient units that lack up-to-date and effective controls for hazardous emissions. Many of these units are slated to retire. In fact, over 20 GW of coal-fired generation have been recently announced for retirement. However, current regulatory provisions do not always sufficiently promote utility planning for these retirements, causing some in the utility sector

---

[72] Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" by Lipinski, Leonard, Richardson; published by URS; April 5, 2011

[73] Ibid.

to delay action and then raise concerns regarding perceived threats to electric system reliability that would not otherwise exist if more advance planning had been done. In the proposed rule, the EPA recognized that "Although most RTOs/ISOs only require 90-day notifications for retirements, construction schedules for all but the simplest retrofits will be longer, so sources should be able to notify their RTOs of their retirements earlier." To provide an incentive for early planning, the EPA said that it "encourages state environmental regulators to consider the extent to which a utility engages in early planning when making a decision regarding granting a 4th year for compliance" with the Utility MACT. The commenter supports the EPA's approach of encouraging utilities to engage in early planning and to timely announce the retirements of the oldest and highest-emitting power plants in the fleet. Notifications of only 90 days are clearly inadequate, and waiting so long maximizes the chance that reliability issues may occur, rather than minimizing it.

Response to Comment 113: The purpose of today's rule is to establish standards to reduce emissions of harmful pollutants in compliance with the requirements of the CAA, not to retire any particular power plants. The EPA continues to encourage utilities to engage in early planning when considering how to respond to the new regulations – whether to comply or to retire the EGU – and appreciates the commenter's support.

4. Flexible regulations.

Comment 114: Several commenters (17004, 17022, 17026, 17028) consider the purchase of electricity to be a major cost of doing business and question the wisdom of imposing a higher cost on businesses through regulatory inflexibility or needlessly short deadlines. These commenters, along with commenter 17887, urge the EPA to consider developing energy policies that will allow businesses to expand and generate jobs by deferring or mitigating price increases through adopting more flexible regulations.

Response to Comment 114: The agency recognizes that electricity cost can be an important cost of doing business for many manufacturers. As such, it has attempted to provide the greatest degree of flexibility permitted by law. However, the agency is under a court-ordered deadline reflected in a Consent Decree that requires that a MACT standard be issued, and EPA is also making revisions to the current NSPS. Implementation deadlines in the final rule are in response to the underlying requirements of the CAA, and any flexibility that the agency can offer must be consistent with the CAA.

Comment 115: Commenter 17692 expresses concern that the proposed rule will increase electricity costs in Louisiana, where businesses depend on adequate and affordable electricity and domestic productivity could be depressed. The commenter believes the impacts of the proposed rule could be much less if the EPA were less strident and more flexible in the rule requirements.

Response to Comment 115: The agency's analysis finds that the national average retail electricity price increase is expected to be 3.1% in 2015. This increase should be understood in the light of the extensive benefits from HAP and non-HAP emission reductions expected from this rule. The EPA has attempted to provide the greatest degree of flexibility permitted by law.

Comment 116: Several commenters (17707, 17824, 18419) state that Alabama uses coal to supply nearly 60% of electricity needs and employs 1500 workers to run the coal-fired power plants. Commenters worry the proposed rule will jeopardize efforts to increase economic growth and job opportunities in the state. The commenter urges the EPA to adopt more flexible standards and timelines to achieve affordable utility bills, stable jobs and reliable power. Commenters 17824 and 18419 state that Alabama Power has spent $2.6 billion to install technologies to reduce emissions from coal-fired units and succeeded in dropping NO_X and SO_2 emissions by 65% since 1996. Commenters consider the proposed rule to be unreasonable and unfounded, with the cost vastly outweighing the benefits.

Response to Comment 116: The agency's analysis shows that the national average retail electricity price is projected to increase by 3.1% in 2015. The EPA has attempted to provide the greatest degree of flexibility permitted by law. The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) and coal-fired generation will not change significantly. The agency has also assessed resource adequacy, and has determined that there is sufficient excess capacity in existence that will help serve load. In addition, the EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 117: Commenter 17648 observes that "the positive economic impacts of the proposed Toxics Rule strongly militate in favor of its adoption. Contrary to the unfounded assertions by critics of the EPA and the rule, the EPA has conducted a technically sound and conservative benefit-cost analysis showing that the proposed rule's benefits are at least five times as high as its costs. With sound, albeit unduly conservative, econometric modeling, the EPA has also determined that the Toxics Rule will promote economic growth and create jobs in both the long and short term." This commenter and commenter 18432 cite the EPA impact analyses by Dr. Charles Cicchetti which confirms this finding and state that the analysis underestimates the Rule's net benefits and positive impacts on the nation's economy. By considering some benefits not monetized in the EPA analysis, Dr. Cicchetti concludes that the proposed rule will create \$52.5 to \$139.5 billion in net benefits annually, create 115,200 jobs, generate annual health savings of \$4.513 billion, annual increases in GDP of \$7.17 billion and \$2.689 billion in additional annual tax revenues, and spur innovation and modernization of EGUs. The commenter states that the study findings show no need to delay implementation of the rule or needlessly duplicate economic analyses already completed.

Comment 118: Commenter 17648 reports that multiple researchers confirmed that the EPA's estimates of economic stimulus are conservative and that the proposed rule will stimulate job growth. The commenter quotes Dr. Josh Bivens of the Economic Policy Institute, who also found that EPA's conclusions were conservative. Dr. Bivens concluded, "The EPA RIA on the proposed toxics rule makes a compelling case that the rule passes any reasonable cost-benefit analysis with flying colors—the monetized benefits of longer lives, better health, and greater productivity dwarf the projected costs of compliance. . . . Whether regulation in general and the toxics rule in particular costs jobs is an empirical question this paper attempts to answer. In particular, this paper examines the possible channels through which the proposed toxics rule could affect employment in the United States and finds that claims that this regulation destroys jobs are flat wrong: The jobs-impact of the rule will be modest, but it will be positive." His report details the following major findings:

1. The proposed rule would have a modest positive net impact on overall employment, likely leading to the creation of 28,000 to 158,000 jobs between now and 2015.
2. The employment effect of the [Toxics Rule] on the utility industry itself could range from 17,000 jobs lost to 35,000 jobs gained.
3. The proposed rule would create between 81,000 and 101,000 jobs in the pollution abatement and control industry (which includes suppliers such as steelmakers).
4. Between 31,000 and 46,000 jobs would be lost due to higher energy prices leading to reductions in output.

5. Assuming a re-spending multiplier of 0.5, and since the net impact of the above impacts is positive, another 9,000 to 53,000 jobs would be created through re-spending.

Commenters 17648 and 18961 also provide information from The University of Massachusetts Political Economy Research Institute, which prepared a February 2011 study of the jobs impacts of the proposed rule and the Transport rule. Based on estimates that the power sector will invest almost $200 billion total in capital improvements between 2010 and 2015 in these 36 states, the researchers found that the total employment created by these capital investments is estimated at 1.46 million jobs, or about 290,000 jobs on average in each of those years.

Response to Comments 117 and 118: The EPA has conducted an updated employment analysis using the approach applied for the proposed rule which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. It should be noted that the agency's employment impact analysis is focused on short-term estimates of impacts from installation and operation of new pollution control equipment, and long-term estimates of impacts for the regulated industry (electric power generation). Our rationale for the analysis and the analysis itself are in the RIA for the rule.

Comment 119: Commenter 18419 asks the EPA to perform a true economic analysis, evaluate the proposed rule with other new and pending regulations and provide more flexible standards and reasonable compliance guidelines.

Response to Comment 119: The EPA has attempted to provide the greatest degree of flexibility in the rule that is permitted by law.The agency's economic analysis is consistent with the guidelines provided by OMB for rules such as this one that are economically significant under EO 12866, an Executive Order issued by OMB in 1993. The agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: 1) the various EO requirements that the agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low-benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, the EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation.

This does not, however, mean EPA has failed to consider cumulative impacts of the regulation. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.
Additionally, the Agency does reflect on the broader cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed at the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html.

The direct benefits of the 1990 Clean Air Act Amendments and associated programs significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits exceed costs combined with extensive uncertainty analysis suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. This conclusion is likely to also be attributable to this rule as shown in the RIA.

5. Job analysis: temporary versus permanent jobs.

Comment 120: Commenters 17811 and 18436 believe that installation of new pollution controls would be a job-growth opportunity in Alabama because money spent on controls for power plants creates high-quality jobs in steel, cement and other materials, as well as in the assembling of the equipment as well as installing and operating it. Commenter 18436 shares the Alabama Fisheries Association estimate that the water-based recreation industry brings in over $1 billion per year to the state's economy though the state ranks third for imperiled fish with 61 bodies of water cited for Hg contamination. The commenter believes the HAP accumulating in the waterways threaten the industry with permanent job-losses and lost revenue.

Response to Comment 120: The EPA finds commenters' economic predictions and statements of benefits to be reasonable. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 121: Commenters 17834 and 18033 disagree with the EPA speculation that job losses will be offset by increasing jobs in air pollution technology production. Commenters believe the proposed rule will decrease job creation and sees no assurance or conclusive data that jobs will be created. Commenters go on to request that the EPA withdraw the proposed rule, citing an unstable regulatory climate and unclear economic impacts. Commenter 18033 quotes economist David Montgomery's testimony before Congress in which he said that "Claims that regulations that raise the cost of doing business will create new jobs are, *at best, a sideshow. Such claims only distract attention from the difficult tradeoffs that must be made between costs and benefits*. "Green jobs" is not a subject that leading economists have usually taken seriously enough in professional journals. Based on the foregoing, it is difficult for EPA to legitimately claim that the proposed rule's benefits analysis is accurate."

Response to Comment 121: The EPA does not have the flexibility to withdraw or delay the rule, which is governed by a consent decree and the requirements of the CAA. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. All of these analyses are found in the RIAs for the respective rules.

Comment 122: Commenter 17930 disagrees with the EPA's prediction of an annual cost of $10.9 billion by 2015 and estimates it to be up to $100 billion annually. The commenter also disagrees with the EPA prediction of new jobs created, because the commenter believes far more plants will shut down than the EPA predicts, resulting in higher job losses. The commenter points out that while jobs running power plants are permanent, the jobs predicted to be created by the proposed rule are short term construction jobs, and will all occur in the same short timeframe for compliance. Further, the commenter states that the EPA estimate does not include the opportunity cost of lost construction jobs due to new power plants that will not be constructed due to the proposed rules.

Response to Comment 122: The EPA has conducted extensive analysis of the rule, which can be found in the RIA. The cost analysis by the agency is based on a peer-reviewed power sector model that has been used in multiple rulemakings affecting the electric power sector over the past 15 years. The EPA has also conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. Overall impact on retail electricity prices nationwide is also anticipated to be modest in light of the significant benefits of the rule. The EPA cannot evaluate the basis for commenter's claim of higher impacts, but on the basis of its own detailed analysis does not find it to be reasonable.

Comment 123: Commenter 17761 questions the EPA estimate that the proposed rule will create jobs. The commenter points out that coal-fired plant closures will lead to the loss of more jobs than the creation of gas-fired units will create because coal-fired plants employ 75-100 people versus 25-30 for a gas plant of equivalent size.

Response to Comment 123: The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. The commenter points to only one potential change in employment, that of a transition from coal to natural gas-fired generation, but does not address other changes, such as jobs created by increases in production of pollution control equipment.

Comment 124: Commenter 17903 agrees with the EPA's job creation estimations for the proposed rule and reports that 20,000 of the new jobs are expected to be in Iowa. The commenter also mentions that utility boards must approve rate increases, and these may not be given at all or will help to control the rate increases claimed by industry.

Response to Comment 124: The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures.

Comment 125: Commenter 19121 says that the EPA appears to have overstated the job creation estimates due to economic growth under the proposed rule.

Response to Comment 125: The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 126: Commenters 16469 and 18500 estimate the potential job losses associated with the closure of coal units could amount to more than 50,000 direct jobs in the coal, utility and rail industries, with a total job loss including indirect jobs of 251,300. Commenters note that the EPA's analysis did not estimate the effects of adverse employment or effects of higher electric rates. Commenter 16469 provides a table (see EPA-HQ-OAR-2009-0234-16469-A1_Table page 15) summarizing estimated direct job losses in the utility, coal and rail sectors by region based on the 2005 electric generation of affected units. Indirect job losses are estimated using Department of Commerce RIMS II multiplier data for the electric, gas and water utility industries, specific to each state and do not account for short-term or permanent job gains from control unit construction and operation. The commenter provides a preliminary assessment of coal "units at risk" on which these related potential job losses are based. The assessment is contained in Attachment 4 (see EPA-HQ-OAR-2009-0234-16469-A1), based on data sorted from the 2007 DOE/NETL Coal Plant Data Base, updated for information on recent scrubber retrofits and retirements. The units included in the screening are more than 40 years old and between 25 MW and 400 MW, without installed or planned scrubbers. The 2005 generation from these units provided a substantial share of total electric generation in several regions (using a 2009 state generation baseline): 18% in the East North Central region, 14% in the West North Central, and 12% in the South Atlantic. In several states, these units supplied 20% or more of total generation.

Response to Comment 126: The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) and coal-fired generation will not change significantly. The agency has also assessed resource adequacy, and has determined that there is sufficient excess capacity in existence that will help serve load. The EPA has also conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. Overall impact on retail electricity prices nationwide is also anticipated to be modest in light of the significant benefits of the rule.

Comment 127: Commenters 17254 and 17409 quote IBEW president Edwin Hill and United Mine Workers of America who both state that as many as 50,000 workers in the utility, mining and railroad industries could lose their jobs in response to the proposed rule. Commenters disagree with the EPA's estimate of short and long-term job growth, believing that the permanent job losses are underestimated and quotes the HIS Global Insight estimate that for every billion dollars spend on compliance with the proposed rule, 16,000 jobs will be at risk and the U.S. GDP will be reduced by as much as $1.2 billion. Commenters ask that the EPA's analysis account for the loss of tax and support for local schools due to job losses.

Response to Comment 127: The EPA analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) and coal-fired generation will not change significantly. The agency has also assessed resource adequacy, and has determined that there is sufficient excess capacity in existence that will help serve load. The EPA has also conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. Overall impact on retail electricity prices nationwide is also anticipated to be modest in light of the significant benefits of the rule.

Comment 128: Commenter 17409 quotes estimates by ICF International that employment income is estimated to drop in response to the proposed rule by about 2 or 2.5 million full-time workers due to retail electricity price increases.

Response to Comment 128: The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy. The EPA cannot evaluate the basis for ICF International's projections, but believes that its own analysis is as accurate, transparent, and well-supported.

Comment 129: Commenter 17839 states that the transition to clean, renewable energy will create many more jobs than may be lost due to the proposed rule and questions if jobs will actually be lost at all.

Response to Comment 129: The EPA agrees that this can be one source of new employment resulting from today's rule. It has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 130: Commenter 17767 reports that their organization could lose 30 jobs as a result of complying with the proposed rule, and the reduced need for coal could put those employed by coal mines or trucking companies out of work as well.

Response to Comment 130: The EPA analysis indicates that coal-fired generation will not change significantly. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 131: Multiple commenters (17811, 18421, 18436) agree with the EPA's projections that the proposed rule will lead to the creation of 31,000 short-term construction jobs and 9,000 long-term utility jobs. The commenter also quotes the World Resources Institute, which announced that compared to overall spending in the economy, spending on environmental protection and clean-up employs more than twice as many workers in construction and 25% more in manufacturing.

Response to Comment 131: The EPA generally agrees with the thrust of commenters' assertions and those of the World Resources Institute. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 132: Commenter 17813 disagrees with the EPA's estimate of created jobs because the commenter expects retirements to be much higher than predicted, costing more jobs. The commenter argues that the jobs the EPA categorizes as new cannot be compared to the permanent jobs lost, because they will be temporary. The commenter also believes the EPA's assessment does not take into account the lost opportunity of construction jobs that would have been created by constructing new power plants that will not be built as a result of the proposed rule.

Response to Comment 132: The EPA disagrees and notes that its analysis indicates that there will be a small amount of coal retirements (less than 2% of all coal-fired capacity) and coal-fired generation will not change significantly. The EPA thus believes there will be modest levels of coal retirements resulting from the rule, and many units slated for retirement are being taken offline for other reasons aside from requirements to reduce emissions. Overall, coal-fired generation is not expected to change significantly since sources are anticipated to install pollution controls. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

6. Natural gas.

Comment 133: Numerous commenters (17403, 17639, 17640, 17797, 17799, 17806, 17829, 17919, 18488, 18023) point out that the compliance dates underestimate the time needed to comply with the requirements and will lead to more coal-fired plant retirements and an increased demand for natural gas, which will lead to fluctuations in natural gas prices. Commenter 17806 specifically states that the compressed timeframe will make it virtually impossible to achieve compliance and significantly increase the cost of power in most regions as well as threaten reliability. Commenter 17919 agrees with the other commenters and cites the NERA Economic Consulting study done in May 2011 that projected average U.S. retail electricity prices in 2016 to increase by 12%, with regional increases up to 24%, with a 13% reduction in coal-fired generation and a 10% decline in electric sector coal demand in 2016. Also, Illinois Power Agency estimates that by 2017 energy bills could jump 65% from current levels. Commenter 18023 refers to the EEI report showing that over 150 GWs of coal units, approximately half of the U.S. coal fleet, is at risk of being unavailable in 2015 due to insufficient time to achieve compliance. This commenter points out that the timeframe strains the supply of equipment and related resources, which increases costs that are passed on to consumers. A footnote offers and estimated electricity price increase of up to 25% in the Southeast.

Response to Comment 133: The agency has prepared analyses of the costs, benefits, and employment impacts associated with the rule and included them in the RIA for the rule. The projected impact on national retail electricity prices is anticipated to be relatively small, and no region of the country is expected to experience a double-digit increase in retail electricity prices as a result of this rule. Although economically vulnerable families could experience some increase in electricity price in 2015, this increase should be understood in the context of the substantial health benefits from Hg, HAP, and reductions of other pollutants that will result. Industry has shown that it can install large amounts of pollution controls and often finds more cost-effective compliance options than the EPA can anticipate. In addition, the EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). Natural gas supplies and reserves have increased significantly in recent years, and prices have remained fairly stable since their peak in the early 2000s.

Comment 134: Commenter 17852 states that natural gas prices are not more volatile than for other comparable commodities. Though not strictly part of the EPA's "beyond the floor" analysis, the EPA's RIA also creates a misimpression by stating that "The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and can even undergo major price swings during short-lived weather events." Simply put, natural gas prices today are not inherently more volatile than other comparable commodities, and the U.S. - given the abundance of natural gas - is likely to experience significantly less volatility than in the past. The commenter and the Bipartisan Policy Center have jointly commissioned an entire report that demonstrates why natural gas price volatility occurred in the prior decades (including due to the federal government discouraging production), and why these concerns are less likely to occur in the foreseeable future. These reasons include: an enhanced resource base due to shale gas, improved drilling technology, improved storage and delivery infrastructure, and the elimination of government price control that artificially constrained production. Furthermore, coal prices have experienced similar volatility in the past, and have been widely reported to be facing upward price pressure due to the export of coal to meet Asian demand.

Response to Comment 134: The EPA's analysis and conclusions concerning natural gas were not intended to suggest abnormal volatility relative to other commodities, but only to acknowledge the volatility that has been observed historically. The reasons given by commenters for expecting less natural gas price volatility in the future are not unreasonable, however, nor are observations about increasing coal demand elsewhere.

Comment 135: Commenter 17725 states that natural gas use is only an option in places where infrastructure exists to supply sufficient natural gas to the EGU and other local needs and reports that year-round reliable gas delivery is rare due to requirements to meet the other needs. The commenter says that gas interruptions are prevalent in the winter, but can happen year-round, and the costs of establishing a natural gas line to a power plant can be tens of millions of dollars or more, and moving a plant to a gas source can take many years. The commenter describes the options for a Norwalk Harbor plant, and explains that the modifications are costly and difficult even before considering the modifications needed to alter the boiler and fuel supply system to allow natural gas combustion.

Response to Comment 135: The EPA's analysis of the impacts to the power sector can be found in the RIA of the rule. The agency has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. For example, the power sector brought online over 140 GW of gas capacity from 2001 to 2003. The EPA will work with relevant authorities to ensure a smooth transition with this rule. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). Natural gas supplies and reserves have increased significantly in recent years, and prices have remained fairly stable since their peak in the early 2000s.

Comment 136: Commenter 17640 explains that a Midwest steel company estimates that a 1 cent per kWh increase in electricity cost would add $10 million annually to company costs.

Response to Comment 136: The EPA has designed a rule with as much flexibility as possible and in accordance with the requirements outlined in the CAA for HAP, and does not expect significant impacts on electricity prices generally. The EPA believes energy efficiency measures can be a complement to this rule, and can be an important tool in helping address emissions. The EPA has not included all the likely additional energy efficiency measures that are likely to occur by 2015, but will continue to pursue energy efficiency improvements throughout the economy, along with other Federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements.

Comment 137: Multiple commenters (17403, 17812, 17868, 18500, 19211) disagree with the EPA estimate for natural gas price changes. Commenter 17812 expects the proposed rule to lead to an increase in natural gas prices as utility companies transition to burning natural gas instead of installing emission controls. The commenters quote NERA estimates that natural gas prices will increase by 17% in 2016, much higher than the EPA estimate of 0.6% to 1.3% increase. This translates to a natural gas expenditure increase by residential, commercial and industrial sectors by $8.2 billion per year, or $85 billion (present value) for 2011-2030. Commenter 17868 agrees that prices will increase more than the EPA estimates and asks that the EPA use a minimum set of natural gas prices such as the provided graph of average national monthly gas prices provided (page 35 of EPA-HQ-OAR-2009-17868-A2). Commenter 19211 sees the projected increase in natural gas prices as a reason manufacturers may lose confidence in the U.S. as a favorable place to do business.

Response to Comment 137: The EPA has provided an assessment of the economic impacts of the rule on the power sector, which can be found in the RIA of the rule. The agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters. IPM modeling of natural gas prices uses both short- and long-term price signals to balance supply of and demand in competitive markets for the fuel across the modeled time horizon. As such, it should be understood that the pattern of IPM natural gas price projections over time is not a forecast of natural gas prices incurred by end-use consumers at any particular point in time. The natural gas market in the U.S. has historically experienced significant price volatility from year to year, between seasons within a year, and even sees major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). These short-term price signals are fundamental for allowing the market to successfully align immediate supply and demand needs; however, end-use consumers are typically shielded from experiencing these rapid fluctuations in natural gas prices by retail rate regulation and by hedging through longer-term fuel supply contracts. IPM assumes these longer-term price arrangements take place "outside of the model" and on top of the "real-time" shorter-term price variation necessary to align supply and demand. Therefore, the model's natural gas price projections should not be mistaken for traditionally experienced consumer price impacts related to natural gas, but a reflection of expected average price changes over the time period 2015 to 2030.

Comment 138: Commenter 17868 discusses the factors that could lead to higher natural gas prices not currently reflected in the EPA impact projections, including industrial load and demand not rebounding to 2008 levels and the influence of liquefied natural gas exports. The commenter asks that the EPA address these factors:

1. Higher natural gas demand for use in vehicles (a la The Pickens Plan) or some amount of transportation electrification.
2. Constraints either on shale resources allowed to be extracted due to regional opposition or reflect drilling restrictions or a cost adder for environmental remediation.
3. Starting oil prices "adapted from AEO 2009," of about $62/bbl for 2011 are well below current oil prices.
4. No documentation of any indication that the gas market module of IPM reflects the drilling lease inventory buildup that may be causing some producers to drill at less economic prices in exchange for cash flow and retention of their lease options.
5. Unclear what the production per well or depletion assumptions are or whether they have been updated (i.e., lowered) for the shift to more shale production.
6. Figure 10-7 from U. S. EPA's proposed rule provides the resource cost curves but no documentation of how they were derived or how the quantity able to be produced economically at prices below $14 per MMBtu was determined. Page 10-13 of U. S. EPA's proposed rule indicates that the undiscovered gas resource is "assumed" to grow at 0.2% per year for conventional gas and 0.75% for undiscovered gas. Nothing provides the basis for testing that assumption's validity. The discussion admits that technology drives the ability to produce undiscovered resources but does not test the technology assumption and no curves are provided at all for the existing discovered resource base.
7. The model covers North America only, so it must be fed an exogenous assumption on LNG imports (or exports) and cannot predict or capture changes in world-wide development and trading of natural gas.

Response to Comment 138: The EPA has provided an assessment of the economic impacts of the rule on the power sector, which can be found in the RIA of the rule. The agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters. IPM modeling of natural gas prices uses both short- and long-term price signals to balance supply of and demand in competitive markets for the fuel across the modeled time horizon. As such, it should be understood that the pattern of IPM natural gas price projections over time is not a forecast of natural gas prices incurred by end-use consumers at any particular point in time. The natural gas market in the U.S. has historically experienced significant price volatility from year to year, between seasons within a year, and even sees major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). These short-term price signals are fundamental for allowing the market to successfully align immediate supply and demand needs; however, end-use consumers are typically shielded from experiencing these rapid fluctuations in natural gas prices by retail rate regulation and by hedging through longer-term fuel supply contracts. IPM assumes these longer-term price arrangements take place "outside of the model" and on top of the "real-time" shorter-term price variation necessary to align supply and demand. Therefore, the model's natural gas price projections should not be mistaken for traditionally experienced consumer price impacts related to natural gas, but a reflection of expected average price changes over the time period 2015 to 2030.

Comment 139: Commenter 17868 asks that the EPA consider the infrastructure (pipeline and storage) issues and other concerns found in the APPA study "Implications of Greater Reliance on Natural Gas for Electricity Generation" found in Appendix M. [EPA-HQ-OAR-2009-0234-17868-A2]

Response to Comment 139: The EPA is familiar with the study and has considered it. The EPA's IPM modeling includes natural gas pipeline requirements for coal-to-gas (CTG) conversions as described in *Documentation Supplement for EPA Base Case v4.10_PTox − Updates for Proposed Toxics Rule* (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf, Section 5.3.2).

Comment 140: Commenter 17627 quotes the Babcock & Wilcox *White Paper MS-14 "Natural Gas Conversions of Existing Coal-Fired Boilers"* 2010 and recommends the EPA project capital costs based on the B&W costs.

Response to Comment 140: The EPA is familiar with the study and has considered it. The EPA's IPM modeling includes a coal-to-gas (CTG) conversion option as described in *Documentation Supplement for EPA Base Case v4.10_PTox − Updates for Proposed Toxics Rule* (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf, Section 5.3.1). In that documentation, Table 5-11 *Cost and Performance Assumptions for Coal-to-Gas Retrofits,* provides details of the assumed cost of boiler modifications for the CTG option. EPA's assumed $250/kW boiler modification cost for a 75 MW unit is conservatively derived from the $50 to $75/kW costs estimated by B&W for somewhat larger units using their "Option 1," as described in the cited B&W paper (http://www.babcock.com/library/pdf/MS-14.pdf). Thus EPA's CTG option and B&W's CTG Option 1, both involve only modifications to the existing boiler; they do not involve higher cost approaches such as the addition of a gas turbine (as in B&W Option 2).

Comment 141: Commenter 17879 explains that much of the manufacturing industry cannot pass along increased input costs because it decreases competitiveness. The paper industry in particular is in decline, the commenter reports, and increased natural gas and electricity costs could exacerbate the nation's weak economic situation. The commenter worries that the widespread conversion from coal or oil to natural gas by power plants will lead to an increase in natural gas consumption and costs.

Response to Comment 141: The EPA has designed a rule with as much flexibility as possible and in accordance with the requirements outlined in the CAA for HAP. As discussed elsewhere in this document, the EPA's analysis shows only modest conversion to natural gas and that coal will continue to play a major role in the nation's energy economy. Additionally, the EPA believes energy efficiency measures can be a complement to this rule, and can be an important tool in helping address emissions. The EPA has not included all the likely additional energy efficiency measures that are likely to occur by 2015, but will continue to pursue energy efficiency improvements throughout the economy, along with other Federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements.

Comment 142: Commenter 17711 discusses the unique concerns of paper mills that produce some of their own electricity, but also purchase some. The commenter is concerned that the proposed rule will increase costs and lead to some plants switching to natural gas, thus increasing the cost of natural gas, putting jobs at risk.

Response to Comment 142: The EPA has designed a rule with as much flexibility as possible and in accordance with the requirements outlined in the CAA for HAP. As discussed elsewhere in this document, the EPA's analysis shows only modest conversion to natural gas and that coal will continue to play a major role in the nation's energy economy. Additionally, the EPA believes energy efficiency measures can be a complement to this rule, and can be an important tool in helping address emissions. The EPA has not included all the likely additional energy efficiency measures that are likely to occur by 2015, but will continue to pursue energy efficiency improvements throughout the economy, along with other Federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements.

Comment 143: Commenter 17853 discusses the cost effectiveness for coal-to-gas with respect to increasing capacity for existing zero HAP base load EGUs, including natural gas. The commenter provides Figure 1, which shows raw commodity prices, which shows natural gas to trend higher than coal, but since natural gas is 1.67 times more energy efficient, natural gas is comparable to coal in commodity prices. (See Insert EPA-HQ-OAR-2009-0234- 17853-A2_Figure1and2Page3.doc.)

Response to Comment 143: . The EPA has provided an assessment of the economic impacts of the rule on the power sector, which can be found in the RIA of the rule. The EPA generally agrees with commenter's assessment, noting that it has designed a rule with as much flexibility as possible and in accordance with the requirements outlined in the CAA for HAP. Source owners will be able to ascertain the viability of coal to case conversion relative to other options for reducing HAP emissions.

Comment 144: Commenters 18480 and 18481 express concern that the cities of Beatrice and South Sioux City, Nebraska will be unable to meet the compliance deadline. Both receive their electricity from the Nebraska Public Power District, and the mix is 50% coal, 40% nuclear and the remainder wind, natural gas and hydro power. The coal plants use low-sulfur coal and have baghouses that have reduced Hg emissions by 50%. An estimate of compliance costs show a preliminary cost of $1 billion, which will lead to a rate increase. The commenters request that the EPA reconsider the proposed rule's aggressive emissions limits and deadlines, in light of the economic effects.

Response to Comment 144: To the extent that sources have already installed significant emission controls, the EPA anticipates that the additional costs of complying with this rule will be much less. As discussed elsewhere in this document, electricity prices are not expected to increase significantly as a result of this rule. Nonetheless, the EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues. Public utility commissions and other regulatory authorities have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 145: Commenter 18486 expresses concern that the combined effect of the new rule will increase the use of natural gas for electric generation and increase natural gas prices, decreasing availability for other uses. The commenter reports that natural gas is used in the production of ammonia for fertilizer and for heating and other purposed in the agricultural industry. The commenter states that other agricultural sectors, such as dairy, are electricity intensive so they will be impacted by the cost increases for electricity and natural gas. The commenter asks the EPA to consider reports by Brattle Group, ICF, Credit Suisse, CRA, FBR, Wood McKenzie and Bernstein Research on the ways the proposed rule will lessen the use of coal and increase natural gas use.

Response to Comment 145: The EPA's analysis of the impacts to the power sector can be found in the RIA of the rule. The analysis indicates that only a small number of coal plants will retire, and coal-fired generation will continue to be the largest source of electricity. The agency has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load after retirements are factored in, and industry has also shown that it can build new capacity quickly in response to demand. The EPA will work with relevant authorities to ensure a smooth transition with this rule. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). Natural gas supplies and reserves have increased significantly in recent years, and prices have remained fairly stable since their peak in the early 2000s. The EPA anticipates this trend will continue although there may be some modest price effects on natural gas markets due to this rule.

7. Compliance timeline and general timeline.

Comment 146: Commenter 17806 considers the compliance time limits imposed by the proposed rule to be impossible to achieve in light of the other final or pending rules. The commenter believes the short timeline for these rules will increase the cost of power in most regions and threaten reliability.

Response to Comment 146: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 147: Commenter 19199 believes the utilities will need more time to comply with the proposed rule in order to acquire the materials and labor needed to construct and install the equipment without creating unnecessary cost increases and an unreliable electricity supply. The commenter believes the EPA should extend the time to allow flexibility in implementation of the proposed rule.

Response to Comment 147: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 148: Commenter 19213 says that the proposed rule does not allow adequate time to comply. The commenter states that the timeline brings a risk of needing to increase electricity rates significantly and negatively impact the economy and federal budget.

Response to Comment 148: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 149: Commenter 19213 states that small utilities will have a difficult time getting vendors and contractors to commit to projects, since large utilities will be seeking larger quantities of equipment.

Response to Comment 149: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 150: Commenter 17834 states that the proposed rule will require costs be passed on to consumers, meaning state public utility commissions will be flooded with requests for rate increases from utilities trying to recover expenditures. The short deadline will also result in a large number of extension requests made to state permitting authorities, further burdening them.

Response to Comment 150: The implementation of this rule will be 3 years after its promulgation, or the end of 2014. Public utility commissions have extensive experience with regulatory requirements and treatment of costs to consumers, and are prepared for responding to the cost of future pollution control equipment or other response measures. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). Thus, there will be some time before the impacts of this rule such as any increase in retail electricity prices become a concern. It also should be noted that increases in retail electricity prices will be 3.1% on average in 2015, with a range regionally from 1.3 to 6.3%. See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 151: Commenters 17743 and 17761 express concern that the short compliance deadline will require many facilities to be taken offline at that same time to make upgrades, leading to reliability issues.

Response to Comment 151: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 152: Commenter 18538 states that the compliance timeline in the proposed rule does not include time to plan and permit new facilities. The commenter believes the EPA assumes owners will be able to determine which plants will retire on the first day of the proposed rule's implementation period. However, the commenter explains that permitting, planning and construction can run longer than 3 years and delays in construction are common. Transmission upgrades can also take longer than 3 years. Since many of the new plants in Texas will be in the same areas, permitting could also take longer.

Response to Comment 152: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 153: Commenters 17881 and 18033 expresses concern that even with a blanket 1-year extension, the proposed rule still poses risk to the reliability of the nation's electricity grid and to national security. The commenter asks the EPA to work with industry to lay the groundwork for the Presidential exemptions, as allowed by the CAA.

Response to Comment 153: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 154: Commenter 15002 states that the proposed rule should regulate emissions to the average emissions achieved by the top performing 12% of sources since this provides a satisfactory balance between emission controls, the monetized value of the associated health benefits and the projected costs. The commenter also urges the EPA to adopt a review schedule for Hg and HAP emissions, such as a 5-year review cycle as defined under the CAA NAAQS review process.

Response to Comment 154: The rule will impose HAP emissions limits consistent with the requirements of section 112(d) of the CAA. Although the EPA has conducted a detailed analysis of the costs and benefits of the rule, the setting of a MACT floor is not based on the costs and benefits of control. Setting standards beyond the MACT floor does consider costs and non-air quality health and environmental impacts and energy requirements. The review cycle for standards such as this one is not longer than 8 years as set forth in CAA section 112(d)(6).

Comment 155: Commenter 17654 reports that they will need to install add-on pollution controls to meet the proposed emission standards as well as implement other physical or operational changes. The commenter expresses concern about the number of pre-construction steps that would be required, as well as the new construction activities and the challenges of scheduling sequence relative to interconnections and other tie-in considerations involved in compliance.

Response to Comment 155: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 156: Several commenters (17681, 17886, 18441) have concerns about the tight timeframe imposed by the proposed rule. Commenters 17681 and 17886 argue against the EPA's suggestion that utilities should commit to capital projects before a final rule is completed. The commenters point out that it is unwise to invest in emission strategies that may not be adequate to comply with the final rule. The commenters state that many companies have had to stop their investments for strategies based on prior rules because they are likely to be insufficient for the proposed rule. Rate-regulated states may not be able to recover capital commitments made before the rule is final. Commenters 17886 and 18441 states that early decisions are not appropriate for a MACT rule as they may be for Clean Air Interstate Rules, since the CAIR is a cap and trade program that allows flexibility, and the proposed rule requires units to meet limits to be shut down. Commenters believe utility decisions on unit retirement versus additional control installations must factor into all anticipated and existing regulations.

Response to Comment 156: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 157: Commenter 19114 has determined that the proposed rule does not provide enough time to permit, engineer, procure and construct the retrofits their fleet will need to meet the 2014 deadline.

Response to Comment 157: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 158: Commenter 17911 explains the different approaches used to obtain funding by a private, stock or cooperative company as opposed to a municipality. A private company comes to an agreement with an entity with funds to lend. Municipalities, on the other hand need approval from the voting public to issue revenue bonds or general obligation bonds to begin the process of financing projects, often by a super majority. Additionally, the commenter states municipalities are bound by publicly adopted budgets that cannot be amended, so it may take up to 18 months to get approval to spend money for projects like those necessitated by the proposed rule. The commenter also explains that municipal bonds have been hit by threatened bankruptcies of municipalities, which makes it increasingly difficult to fund projects and many municipalities have seen a reduction in their revenue streams, including sales tax and water, wastewater or electricity utility bills. A downgrade in the U.S. credit rating may also change municipal borrowing ratings, making money increasingly difficult to borrow. Municipalities are legally prohibited from skipping or speeding up regulatory or legal processes. All of these factors make it difficult for municipal utilities to move forward quickly with construction of new controls or generation.

Response to Comment 158: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). In addition, the deductibility of federal tax on capital investment by municipalities may make investment in pollution control somewhat less expensive relative to private, stock or cooperative companies, who do not have this tax advantage for debt.

Comment 159: Commenter 18447 explains that they will not be able to plan, design, permit, bid and build a new transmission line in 3 years. The commenter states that they have been working to build a new transmission line without success since 2005. The commenter says that the initial cost estimate was $18.2 million, but has now surpassed $29 million and will not be completed until 2012. The commenter explains that when the city power plant is down, without this transmission line the power in the city will go out any time the demand is greater than 63 MW. The commenter also says that committing resources toward rule compliance before it is finalized is not an option as resources are only available when the need is known.

Response to Comment 159: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 160: Commenters 17808 and 18421 do not believe that labor availability will constrain control installation in the required timeframe and cites ICAC response that it will not for these reasons:

1. Power sector has demonstrated ability to install large number of systems in short time period.
2. Majority of coal plans have installed control systems already.

3. Fewer resource and labor-intensive control options being used for compliance.
4. End users have utilized cost reducing and implementation efficiency strategies for efficient deployment of technologies.

Response to Comment 160: The EPA thanks the commenter for their comments. These comments are generally consistent with the conclusions of the agency's analyses on feasibility of control installations for this rule as found in the TSD on this subject in the docket for this rulemaking.

Comment 161: Commenter 18498 considers the compliance schedule to create a regulatory environment where reserve capacities will decrease and consumer costs will increase. The commenter cites studies showing the proposed rules and others will cause 10 to 70 GW of coal retirement between 2015 and 2020. The commenter explains that replacement capacity cannot be operational prior to the compliance timelines for retirement or retrofits of existing facilities. This results in an inefficient and costly approach that could be addressed by extending the compliance deadlines to allow sufficient time to plan for transition to other technologies in a manner that is cost effective and assures grid reliability. The commenter requests the compliance deadlines to be increased to at least 5 years with extensions allowed for 2 additional years.

Response to Comment 161: See preamble and TSD on feasibility for further discussion. The EPA has analyzed resource adequacy issues and finds that there is ample existing spare capacity to serve load, and industry has also shown that it can build new capacity quickly in response to demand. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). As discussed further in the preamble, compliance timeframes are prescribed by the CAA.

Comment 162: Commenters 17812 and 18038 suggest that market realities of installing control equipment will increase the cost of the equipment due to the timeframe for compliance. Commenter 18038 is especially concerned that the short timeline and resulting increases in costs will be a hardship for those already having difficulty in the current economy.

Response to Comment 162: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 163: Commenter 18435 states that a wide range of technical and economically feasible practices and technologies are available currently to meet the emission limits and are in use around the country.

Response to Comment 163: The EPA agrees with the comment. Our report on feasibility of controls to meet the requirements of this rule can be found in a TSD in the docket for this rulemaking.

Comment 164: Commenter 17403 disagrees with the employment impacts estimated by the EPA and the estimated number of units expected to retire. The commenter states that a longer timeline would allow the EPA to preserve employment opportunities while protecting the environment.

Response to Comment 164: The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 165: Several commenters (17409, 17736, 18441) express concern over the 36-month compliance timeframe and urge the EPA to provide an extension of at least 1 year to avoid more plant retirements and lost jobs than necessary. Commenters 17736 and 18441 go on to request a clear explanation of the requirements to qualify for an extension and commenter 17736 requests automatic qualification for replacement source provisions, regardless of location while commenter 18441 does not request a blanket delay.

Response to Comment 165: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble).

Comment 166: Commenter 17627 discusses the length of time it takes to adhere to permitting requirements and the time needed to design, engineer, fabricate and install equipment. The commenter explains that all these resources will be limited as multiple facilities try to utilize them during the short timeframe and several commenters (17881, 17911, 18933, 19212) agree with this assessment. Commenter 19212 reports that the compressed timeline will inflate costs to twice that of a more reasonable implementation period of 6 to 8 years, which is wasteful of rate payers money. The commenter suggests petitioning Congress for additional time to ensure a reasonable outcome.

Response to Comment 166: See preamble and TSD on feasibility for further discussion. In addition, there are certain provisions for granting utilities some additional time to comply, if conditions warrant (see preamble). As discussed further in the preamble, compliance timeframes are prescribed by the CAA.

Comment 167: Commenter 18025 explains that between 2008 and 2010, approximately 60 GW of coal capacity was retrofitted with scrubber controls and the industry completed between 50 and 60 scrubber retrofits in each of the years 2009 and 2010, which shows the industry can complete large numbers of retrofits in a short time period. Commenter 18025 encourages the EPA to finalize the rule on the planned schedule to avoid market uncertainty.

Response to Comment 167: We agree with the commenter and are issuing the rule consistent the consent decree.

Comment 168: Commenter 18477 estimates that compliance with the proposed rule will require new controls on 10 of Hawaiian Electric’s 14 steam boilers, and the controls cannot be completed until 2018 without jeopardizing system reliability. This would increase costs for consumers by 5% in 2014, and trend up to 10% for 2018 and later years. The commenter notes that the remaining boilers would be retired, and the cost of replacement generation was not included in the estimates.

Response to Comment 168: See preamble for discussion of requirements for non-continental liquid oil-fired EGUs.

Comment 169: Commenter 18538 believes the EPA has underestimated the time needed to plan, permit and construct sufficient new generation and transmission to compensate for the retirements caused by the proposed rule.

Response to Comment 169: The claims of retirements in recent studies of the impact of EPA rules are addressed in the preamble for the final rule.

Comment 170: Commenter 19121 states that the rule's timeline combined with over-regulated HAP place a threat to grid reliability.

Response to Comment 170: The claims of retirements in recent studies of the impact of EPA rules are addressed in the preamble for the final rule. As discussed in this document, the preamble, and other supporting materials, the EPA disagrees that HAP are "over-regulated" by the rule.

8. Large burden, little environmental gain.

Comment 171: Several commenters (17681, 17731, 17761) state that the EPA has no data relating to benefits from reducing non-Hg HAP, so the costs of the proposed rule exceed the HAP benefits by 29,000 times. Commenter 17761 states that the impact analysis was largely focused on Hg with little support for other HAP reductions and failed to provide account of true costs and benefits.

Response to Comment 171: The benefits of this rule include the reductions in non-HAP emissions such as SO_2 and $PM_{2.5}$ that will take place based on the EPA's modeling. These reductions are credible and are considerable in size. The estimates of these benefits reflect extensive analysis that has been reviewed by the EPA's SAB, and reflects the latest scientific understanding on the subject. These benefits outweigh the total annual costs of the rule by at least six-fold. More information on the estimates and the methodology for their preparation can be found in the RIA for the rule. In addition, we are not able to monetize the benefits from reductions of non-Hg HAP that will take place, but it is clear that benefits will occur from reductions of these HAP.

Comment 172: Several commenters (17765, 17840, 17931, 18018) state that the rule is one of the most expensive in the history of the CAA and is a huge regulatory burden for little environmental gain. Commenter 17840 states that a precise cost estimate for the proposed rule is not possible because of the number of interrelated rules to be considered. The commenter states that little to no incremental public health benefits will be realized in response to the proposed rule.

Comment 173: Commenter 17842 cites the EPA estimate that the rule will cost $10.9 billion and create social benefits of $42 to $140 billion annually and states that other analyses suggest costs will be more severe due to the cumulative impact of interrelated emission regulations.

Response to Comments 172 - 173: The EPA's analysis of the impacts to the power sector can be found in the RIA of the rule. Industry has also shown that it can build new capacity quickly in response to demand. The EPA has not provided a cumulative impact analysis of various rulemakings for a variety of reasons, which are outlined in the preamble and elsewhere in this document.

Comment 174: Some commenters (17623, 17656, 17799, 17917, 17919, 18023) consider the proposed rule to be the most expensive clean air rule ever. They point out the estimated $10.9 billion annual cost in 2015 and approximate 1,200 existing coal-fired EGUs affected, both of which were estimated by the EPA. Several commenters (17656, 17681, 17917) believe the EPA's estimates are incorrect and the true cost will be far more due to cumulative effects of all proposed power sector rules, and indirect costs from job losses, reduced productivity and competitiveness resulting from electricity costs. Commenters ask the EPA to keep these high costs in mind when evaluating impacts of the proposed rule and consider the costs with respect to the benefits. Commenter 17681 in particular requests that the EPA explain how its approach utilized "the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible." and include analyses by EIA, EEI, NERC, NERA, Credit Suisse, ICF and Burns & McDonnell.

Response to Comment 174: The EPA's analysis of the impacts to the power sector can be found in the RIA of the rule. The methodology applied in that analysis was subjected to extensive external peer review and this is documented in the RIA and supporting materials. In contrast, not all of the analyses cited by the commenters are completely transparent, and the lack of sufficient documentation of methodologies and assumptions prevents the EPA from subjecting them to critical review. Industry has also shown that it can build new capacity quickly in response to demand. The EPA has not provided a cumulative impact analysis of various rulemakings for a variety of reasons, which are outlined in the preamble and elsewhere in this document. The EPA has conducted an updated employment analysis which shows some potential positive and negative employment changes from the rule, but overall expects the employment impact to be relatively small in comparison to the affected sector and the overall economy.

Comment 175: Commenter 17637 states that the emission reductions achieved by the proposed rule would be realized by other rules such as the NAAQS for PM, SO_2 and SO_3 and related transport rules. As such, the benefit of adding further control equipment and work practices will be minor.

Response to Comment 175: The emission reductions from these rules are based on the agency's best estimates of how emissions of HAP and non-HAP pollutants are affected by the control options examined for this proposed rule. The RIA accounts for the impacts of other previously adopted rules. These reductions in emissions lead to substantial benefits associated with the rule as shown in the RIA for the rule.

Comment 176: Commenter 17386 reports that their municipal plant will incur significant costs while removing minimal HAPS from their two small (28 MW and 114 MW) units, which have limited operating time and combust only fuel oil and natural gas.

Response to Comment 176: Natural gas-firing is not impacted by this rule, and the EPA has included analysis for some modest improvements available to oil-fired units to achieve compliance, which can be found in the RIA.

Comment 177: Multiple commenters (17403, 17640, 17751, 17774, 17775, 17921, 18026, 18033, 18488, 19114, 19211, 18023) quote the NERA study that looked at combined economic impacts of the proposed rule and the Transport rule and projected an $18 billion per year cost. The study also estimates an increase in electricity prices of 11.5 to 23% and an increase in natural gas prices as a result of the proposed rules as well. Commenters go on to say that manufacturers will not all be able to absorb the higher costs and quotes the NERA study's prediction of 1.44 million job-years lost by 2020 if the proposed regulations are implemented. Commenters 17774 and 17775 agree with this and quote the estimate of 48 GW of coal-fired electric generating capacity (15% of the U.S. fleet) projected to retire in response to the proposed rule. Commenter 17921 states that not all potential health benefits of the proposed rule are monetized in the EPA impact analysis, so the total benefit of $50 billion per year is likely to be a low estimate. However, the benefit still exceeds the costs predicted by the EPA or NERA, and the commenter believes the rule will benefit children's health and carry a financial benefit as well. Commenter 18026 states that Ohio can't afford the job losses or price increases. Commenter 19114 points out that new natural gas units require 75% fewer people per megawatt of capacity than coal. Commenter 19211 states that some manufacturers will be unable to absorb the price increase and will have to close or decrease production.

Response to Comment 177: The agency's analysis finds that the nationwide average increase in retail electricity price is 3.1% in 2015, and no region of the country will experience an increase in price of greater than 6.3%. Natural gas prices will increase as an outcome of the rule, but the increase will be no more than 1% on average from 2015 to 2030. We estimate 4.7 GW of coal-fired EGU capacity will retire early by 2015 and that short-term construction labor will experience an increase of 46,000 job-years as an outcome of the rule. Also, in the long-term, there is an impact on labor on an annual basis ranging from a loss of 15,000 jobs to an increase of 30,000 jobs associated with the rule. Finally, the benefits of the rule are estimated to exceed the $9.6 billion annual cost of the rule in 2015 even though there are several benefit categories that could not be monetized, including the health and other effects associated with non-Hg HAP. All of these analytical results can be found in the RIA for the rule, and various TSDs for the rule also further document various results and the methodology for their estimation.

Comment 178: Commenter 17702 believes that by expanding the proposed rule beyond what is necessary to meet the remand and vacatur, the EPA created additional costs without improving air quality.

Response to Comment 178: The agency has issued its rule consistent with the DC Circuit Court's vacature and with the requirements of CAA section 112(d).

Comment 179: Some commenters (17800, 17806, 17884, 18014, 18018) consider the estimated costs of complying with the proposed rule ($10.9 billion in 2015) to outweigh the estimated benefits of controlling toxic emissions ($4 to $6 million) and therefore neither "appropriate" nor "necessary" as required.

Response to Comment 179: The benefits of this rule include the reductions in non-HAP emissions such as SO_2 and $PM_{2.5}$ that will take place based on the EPA's modeling. These reductions are credible and are considerable in size. The estimates of these benefits reflect extensive analysis that has been reviewed by the EPA's SAB and reflect the latest scientific understanding on the subject. These benefits outweigh the total annual costs of the rule by at least six-fold. More information on the estimates and the methodology for their preparation can be found in the RIA for the rule. In addition, we are not able to monetize the benefits from reductions of non-Hg HAP that will take place, but it is clear that benefits will occur from reductions of HAP emissions from EGUs. Conclusions regarding the appropriate and necessary finding under section 112(n)(1)(A) of the CAA can be reviewed in the elsewhere in the final rule record.

Comment 180: Several **c**ommenters (17765, 17840, 18033) find the proposed rule to produce little to no public health or environmental benefit while imposing unnecessary costs or losses of employment. Commenters state that the pollutants are already regulated under the NAAQS program or other regulations.

Response to Comment 180: The agency has estimated the benefits of this rule to be 5 to 13 times the size of the costs in its RIA. Thus, this rule will be beneficial given this comparison of benefits to costs. The reductions of pollutants regulated under the NAAQS are co-benefits from the HAP emissions limit requirements in the rule, and occur concomitantly with the HAP reductions.

Comment 181: Commenter 18421 cites the EPA's estimate that the proposed rule will yield monetized net benefits of up to $130 billion every year, once the rule is in place. These benefits outweigh the costs by 5 to 13 times. The commenter explains that the estimates are conservative since not all benefits could be monetized, such as health and ecosystem benefits of reducing nitrogen and sulfur emissions and deposition and vegetation benefits from reducing ozone.

Response to Comment 181: The agency agrees with the commenter.

Comment 182: Commenter 18428 considers the proposed rule to be very costly while offering few benefits. The commenter points out that since the year 2000, their company has achieved a 62% reduction in Hg.

Response to Comment 182: The agency has estimated the benefits of this rule to be 5 to 13 times the size of the costs in its RIA. Thus, this rule will be beneficial given this comparison of benefits to costs. The benefits and costs from additional mercury reductions are included in these estimates. To the extent that companies have already installed significant emission controls, the costs of complying with this rule will be less.

Comment 183: Commenter 19041 considers the health benefits to be overstated and the costs underestimated. The commenter and commenter 19114 cite the AEP estimate of $6-8 billion in capital costs needed in addition to the $7.2 billion already spent since 1990, and a retirement of 6,000 MW of capacity to comply with the proposed rule. The commenters say that if one utility will need to do so much to comply, the EPA estimate must be low

Response to Comment 183: The agency has provided the most accurate estimates of benefits and costs possible using peer-reviewed models and comprehensive data. The RIA for this rule explains the basis for the benefits and costs and the uncertainties in the results. The agency also estimates that about 2% of coal-fired EGU capacity nationwide may retire early as a result of the rule, and this estimate is based on calculations from IPM, a peer-reviewed model.

Comment 184: Commenter 18477 asks that the EPA consider the natural air quality that exists in Hawaii and other island locations. The commenter explains that trade winds give Hawaii and other islands some of the best air quality in the nation such that they meet all the NAAQS, so the proposed rule would have minimal impact on air quality despite high costs. The commenter urges the EPA to develop a separate RIA for non-continental oil-fired units.

Response to Comment 184: This rule is a NESHAP, not a rule to implement a NAAQS, and is imposed nationwide consistent with section 112 of the CAA. However, the EPA has adopted provisions for non-continental liquid oil-fired units in the final rule and has provided an analysis for non-continental oil-fired units as part of the RIA for the final rule.

9. State regulators.

Comment 185: Commenters 16859 and 17174 request that the EPA consider the burden of the proposed rule and other recently promulgated rules on the resources of individual states. Commenters ask that the EPA develop a rule that reduces air pollution and provides efficient implementation and enforcement strategies for the delegated authorities. Commenter 16859 asks that the EPA consider ways to secure federal funding for states to cover costs associated with state implementation of the proposed rule and details the many obligations and costs for state agencies. The commenter explains that costs of implementation of the rule can be covered two ways. The first is through U. S. Congressional appropriations. The other is through increases in permit fees allowed for Title V activities in the CAA. The commenter says it may not be expedient to receive state legislative approval for permit fee increases and states that if the EPA estimates state administrative costs, along with state direct compliance costs, the estimates might assist both the EPA in justifying their request for appropriations and states in justifying permit fee increases. The commenter requests the EPA consider state administrative costs and make this information available as directed in UMRA, EO 12866 and EO 13132. The commenter urges the EPA to accurately assess the implementation costs on states, so the rule may be implemented properly and in a timely manner to avoid adverse health effects.

Commenters 16859 and 17400 explain that for each new EPA rule, states may incur slightly different implementation costs. These commenters note that cost categories vary from state to state depending on legislative and regulated community differences. One commenter asks that the EPA consider state costs for a wide-range of implementation start-up and recurring activities in the implementation cost estimation for this rule, while others discussed in the attachment included with the original comment. The attachment details several implementation costs that must be accurately assessed for the rule to be implemented properly and in a timely manner without adversely affecting human health. The commenter also asks that the EPA seek federal funding for the states to cover the customary portion of the costs associated with state implementation and consider the availability of funding support in its planning for new rule adoption schedules and other implementation activities following the rule issuance.

Response to Comment 185: The agency has addressed the impacts on state and municipal agencies in compliance with UMRA and EO 12866 and 13132. Additionally, the EPA estimated the costs of implementation of the rule to states and has included this analysis in the RIA. The agency has updated this analysis for the final rule and included it in the RIA. The reductions in air pollution from the rule should be substantial and are well elaborated on in the RIA and in technical support documents found in the docket for this rulemaking. The agency will respond accordingly to requests for additional state and local agency funding if it is determined that such funding is needed for implementation of this rule.

Comment 186: Commenter 17629 explains that a settlement agreement on a rate case in Wyoming created a new layer of review by Public Service Commission to examine the Public Need and Necessity for passing on environmental control costs to consumers. The commenter anticipates that the analytical burden associated with this rule and others recently proposed will increase and reliance on the EPA's technical and economic analyses will not be sufficient. The commenter urges the EPA to take steps to change the Grant Agreements to reflect the additional burdens to states.

Response to Comment 186: The agency may consider changing Grant Agreements and help states in other ways if the analytical burden to them is substantial enough to warrant agency action.

Comment 187: Commenter 17620 discusses the increased workload of state and local air pollution control agencies as a result of the proposed rule. The commenter explains that the EPA has proposed a number of alternate compliance options that will reduce compliance costs for industry, but increase the cost of administering the program. The commenter states that in delegated states, permitting authorities will also conduct inspections and commence enforcement actions where sources are found to be in noncompliance, which is important because of the large amount of toxic air emissions that are involved, but cannot be undertaken without resources. The commenter points out that increased funding is unlikely to be available and urges federal grant funding be provided under sections 103 and 105 of the CAA during those years when the majority of implementation activities will occur.

Response to Comment 187: The agency will respond accordingly to requests for additional state and local agency funding if it is determined that such funding is needed for implementation of this rule.

Comment 188: Commenter 17620 states that the reductions in SO_2 and $PM_{2.5}$ required by the proposed rule will assist state and local air pollution control agencies to meet health-based air quality standards, reduce haze and improve visibility. The commenter points out that substantial reduction in emissions made by the very large sources under the proposed rule will lead to fewer pollution controls needed at smaller sources to meet health-based ambient air requirements. This is a far more cost-effective approach than controls at smaller facilities and is the lowest cost path to improved public health and a cleaner environment.

Response to Comment 188: The EPA thanks the commenter for the comments. The MATS is a standard to reduce HAP, but we are also finalizing revisions to the NSPS for NO_X, SO_2, and PM emissions limits for utilities. Much of the HAP requirements will also lead to co-benefits such as $PM_{2.5}$ and SO_2 reductions that could be of aid to states working on implementation of various NAAQS and regional haze strategies.

Comment 189: Commenters 17743 and 17745 express particular concern over the proposed rule's impacts on the burden on the permitting authorities in light of the other current and pending EPA air rules also adding to the expected workload. Commenters 17174 and 17834 ask the EPA to consider the burden of the proposed rule that is placed on state agencies and develop a rule that reduces air pollution but provides for efficient implementation and enforcement.

Response to Comment 189: The agency is careful to mitigate the impacts of this rule to permitting authorities to the extent possible. The agency will respond accordingly to requests for additional state and local agency funding if it is determined that such funding is needed for implementation of this rule.

10. Miscellaneous.

Comment 190: Commenter 18447 asks that the EPA consider the best interest of the U.S. in creating policies. The commenter asks if other countries are willing to hurt their economies to be a good global neighbor and states that history shows they will not.

Response to Comment 190: The agency has prepared this rule in response to the requirements of the CAA and a court mandated consent decree. The vast majority of benefits resulting from this rule will be experienced in the U.S., not outside of it. Additionally, through a variety of working groups and treaty organizations, the EPA participates in international negotiations to address transboundary air pollution and to achieve a level playing field in the control of air pollution.

Comment 191: Commenter 17409 quotes a Stanford University study that says the U.S. could be run entirely on clean energy within 10 years, at reasonable cost. The commenter goes on to acknowledge other innovations in the power generation industry and points out that new regulations inspire new knowledge and industries find new ways to do things better, and more cheaply, making the U.S. more competitive in the global market.

Response to Comment 191: We agree with the commenter that new regulations such as this rule could serve to spur innovation to make energy production cleaner, a trend already distinct in the electric power sector and that innovation has historically occurred at a more rapid pace than predicted.

Comment 192: Commenter 17855 discusses the difficulties for waste coal industry in complying with the proposed rule. The commenter explains that the waste coal industry is reclaiming abandoned mining sites to avoid discharging acid mine drainage, at no cost to the taxpayers. The commenter explains that waste coal power plants control NO_X and SO_2 and PM currently, but may be forced to install expensive new controls, which may make the plants economically unviable and lead to an end of mine remediation without public funding. The commenter explains that waste coal plants are small plants designed to use local waste coal and which do not have the ability to pass costs on to customers or switch to another fuel to meet proposed limits.

Response to Comment 192: As noted elsewhere in this document, coal refuse-fired EGUs are among the units making up the MACT floor pools for all of the HAP. Thus, we believe that such EGUs are capable of achieving the limits in the final rule and are not economically unviable as suggested by commenter. Should additional controls be required at certain facilities, such controls can be added just as at other EGUs. Facilities that have already achieved significant control of emissions are likely to face lower costs to comply with today's rule.

Comment 193: Commenter 17867 explains the Boardman 2020 Plan as an innovative approach to achieving environmental goals by ending coal-fired generation at relatively young and efficient EGUs. The commenter cites to key features contributing to successful discussions among diverse stakeholders to produce an outcome that achieved a remarkable level of consensus for the future of the Boardman Plant and for the people and natural environment of Oregon:

1. A state-adopted agreement with broad and diverse stakeholder support;
2. An enforceable agreement to cease coal operations by a date certain;
3. A reasonable amount of time before the end of coal operations to address concerns regarding community impacts, including jobs at the facility, replacement of the energy resource that considers cost to customers, reliability and resource diversity, and consistency with CAA requirements;
4. Interim emission controls that appropriately address human health and environmental impacts for the remaining period of coal-fired operations; and
5. A robust resource planning process that considers low carbon replacement resources among the viable alternatives.

In the case of Boardman 2020, the commenter explains the combined strategy of early cessation of coal operations and interim controls will result in lower aggregate emissions of haze causing air pollutants than those projected under a much more expensive control package that would have otherwise been required to run the plant indefinitely.

Numerous commenters (13902, 14279, 14481, 14695, 14696, 15161, 15590, 15636, 15680, 15823, 15824, 15883, 16406, 16681, 16683, 16825, 17021, 17153, 17194, 17298, 17307, 17308, 17847, 17867, 17872, 17874, 17894, 17899, 17900, 18052, and 18485) urge the EPA to recognize and accommodate appropriate solutions like Oregon 's Boardman 2020 plan to allow the agreement to be fully achieved. The commenters believe that the final NESHAP rule for EGUs needs to clearly recognize this innovative Oregon approach and provide regulatory flexibility to accommodate the Boardman plan within the framework of the CAA. The Boardman 2020 Plan is discussed in further detail by commenters 17867 and 18019.

Response to Comment 193: We thank the commenters for their comments. The timing for implementation of this rule is set in the CAA. We will allow flexibility in compliance, both in method and timing, consistent with the CAA.

Comment 194: Commenter 18039 believes that power plants in Massachusetts and other states with reduced Hg limits have been placed at a competitive disadvantage and do not get the full benefit of their own reductions as a result of being downwind of states which do not impose similar rules. The commenter sees the proposed rule as going a long way to address this current inequity.

Response to Comment 194: We agree with the commenter that implementation of this national rule may level the playing field, as it were, regarding Hg controls across the country.

Comment 195: Commenter 18961 believes the rules will level the playing field by imposing universal standards for all coal-fired units, reducing uncertainties in the industry and easing long-term planning. The commenter points out that the standards can be met through existing technology within the compliance timeline. The commenter also believes that by retrofitting or retiring out-dated coal-fired power plants, the industry will improve the reputational risks and relations with local communities and regulators. The commenter shares results from a poll saying that 79% of Americans are in favor of the EPA placing stricter limits on Hg from power plants.

Response to Comment 195: The EPA agrees with the commenter.

Comment 196: Commenter 19042 cites the Executive Orders and policy directives from the Obama Administration that encourage federal agencies to increase sustainability, reduce emissions and conserve energy. The Administration claims this will reduce electricity costs by $1.7 to $2.1 billion from 2010 to 2020. However, the commenter points out that the capital costs are not included in these estimates, and even if no capital costs were needed, the reduction would still be less than the increase due to the proposed rule. The commenter also points out that there has been significant interest in the proposed rule in Congress, and it may be appropriate for review under the provisions of the Congressional Review Act. The commenter states that the impacts analysis is flawed because:

1. it fails to account for the unfunded mandate to every department and agency of the federal government that either generates or purchases electricity;
2. our analysis of the RIA found no discussion of federal budget costs;
3. there are no estimates reported by the federal departments and agencies in their budget projections or in the budget justification materials provided to Congress; and
4. based on informal contacts with senior federal facility energy managers, we have found no evidence that interagency review of the Utility MACT standards considered federal compliance costs and budgetary priorities.

Response to Comment 196: Every major rule is subject to the CRA and this rule is no exception. UMRA is inapplicable to instrumentalities of the federal government and by its terms applies to federal actions that have impacts on state, local, tribal governments or private entities. The EPA's analysis projects a near-term increase in the average retail electricity price of 3.1% in 2015 falling to 2% by 2020 under the final rule in the contiguous U.S.

Comment 197: Commenter 19042 discusses the federal deficit of $1.6 trillion and the states' deficit of $130 billion and points out that the proposed rule will affect the federal budget in two ways:

1. direct compliance costs to electric generating units (EGUs) owned by federal agencies; and
2. pass-through compliance costs paid in the form of higher prices for electricity purchased by federal agencies.

Response to Comment 197: The agency estimated the increase in direct compliance costs at federally-owned EGUs, and that estimate for the proposed rule is available in the docket. This estimate has been revised for the final rule. The agency estimated the retail electricity price nationwide to increase on average by 3.7% in 2015 as a result of the rule. The agency does not expect this increase in price to lead to significant increases in federal government agency operating costs.

Comment 198: Commenter 19042 notes the EPA identified 96 state and local government entities with a combined total of 169 EGUs that will have to comply with the Utility MACT standards. For these potentially affected units, the EPA estimated the cost of compliance, setting that cost equal to the change in operating and capital expenditures, plus the change in fuel costs, plus the change in revenues resulting from the sale of electricity to consumers at presumably higher retail prices.

The results of the EPA UMRA analysis are depicted in Table 1 and Table 2 in the original letter. (See EPA-HQ-OAR-2009-0234-19042-A2, 19042_Table_1.doc and 19042_Table_2.doc.)

In the RIA, the EPA notes that its "[UMRA] analysis does not examine potential indirect economic impacts associated with the proposed [Utility MACT] rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

Each agency's annually updated SSPP is intended to prioritize agency sustainability activities based on lifecycle return on investment. OMB provides periodic evaluation of each agency¡¦s performance via a Sustainability and Energy Scorecard (SES). All scorecards are published on CEQ's website.[33] Agencies' SSPPs show that OMB assigned a "green light" score to the proposed scope 1 and 2 GHG emissions targets set by the federal agencies with the largest electricity consumption. The commenter goes on to say that the Administration claims that achievement of the scope 1 and 2 GHG emissions targets will reduce federal spending. In particular, with respect to purchased electricity, in recent testimony before the U.S. Senate, CEQ Chair Nancy Sutley made the following statement:

"If annual greenhouse gas emissions decrease incrementally to produce a reduction equal to five % of calculated base year emissions, the Federal government will save an estimated $1.7 to $2.1 billion in avoided utility costs over the period 2010 to 2020." However, the commenter points out that the Administration provided no justification for the proposed savings. More importantly, the Administration has provided no estimates of the upfront capital investment that will be required in order to deploy new clean energy and energy efficiency measures need to achieve the savings. The commenter points out that the cost of electricity purchases is a significant cost in the federal budget. As a result of the proposed Utility MACT standards, these costs will increase, obviating any potential savings claimed by the Obama Administration due to implementation of EO 13514: Federal Leadership in Environmental, Energy, and Economic Performance. The commenter states that their analysis shows that the SSPP reports and scorecards failed to report the base year electricity and associated GHG emissions data, so it is not possible to determine the percent reduction in GHG emissions associated with electricity consumption. Thus, these assertions may have more of a political bent than an analytical basis. (See http://www.whitehouse.gov/administration/eop/ceq/sustainability/omb-scorecards.)

Response to Comment 198: The agency estimated the retail electricity price nationwide to increase on average by 3.7% in 2015 as a result of the rule. The agency does not expect this increase in price to lead to significant increases in federal government agency operating costs.

Comment 199: Commenter 19042 provides analyses of the estimated federal budget impacts, taking into account the variation by region. However, since publically available data is aggregated by agency, disaggregation by region was not possible, and the commenter suggests the government do this analysis. Instead, the commenter based estimates on federal activity within each state. The commenter used the EPA RIA price increase to estimate federal electricity costs incurred due to the proposed rule. The result was an increase of $166 million per year. The commenter recommends further analysis to estimate the magnitude of the unfunded mandate being imposed on states and local governments and the cumulative impact of pending EPA rulemakings.

Response to Comment 199: The agency has revised its UMRA analysis for the final rule. The agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: 1) the various EO requirements that the agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low-benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, the EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation.

This does not, however, mean EPA has failed to consider cumulative impacts of the regulation. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the broader cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed at the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html.

The direct benefits of the 1990 Clean Air Act Amendments and associated programs significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits exceed costs combined with extensive uncertainty analysis suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. This conclusion is likely to also be attributable to this rule as shown in the RIA.

Comment 200: Commenter 17690 believes the proposed rule could have unintended impacts on deregulated oil-fired units that rely on operating revenues and will be unable to have enough projected revenues to justify the cost of compliance. These units may be prematurely retired.

Response to Comment 200: Our analysis of the impact of the rule on oil-fired units indicates that the costs per unit should be modest, and thus the probability of premature retirement for such units is low.

Comment 201: Commenter 17648 considers the EPA to have coordinated the various programs involving power plants to be effective and explains how the IPM modeling shows the benefits of implementation of the rules. The commenter reports investing nearly $5 billion in clean energy generation and Smart Grid technology and from this experience considers the EPA’s modeling to be unduly conservative. The commenter agrees with the EPA’s modeling that shows the closure of older plants and replacement by gas-fired plants of various types and believes that expansion of nuclear and alternative energy sources will occur as well. The commenter also explains that the proposed rule and other new regulation will increase the efficiency of the fleet, further benefitting the economy. The commenter questions the report, "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations" because it does not account for increased efficiency of gas-fired plants and used the wrong conversion factors from methane to carbon dioxide equivalents.

Response to Comment 201: We agree with the commenter that this rule could lead to an increase in the energy efficiency of the electric power boiler fleet.

6J - Impacts/Costs: Social Costs

Commenters: 11107, 16207, 16824, 16850, 17254, 17408, 17409, 17620, 17709, 17713, 17727, 17766, 17775, 17811, 17842, 17875, 17884, 18432, 18435, 18436, 18541, 18961, 19536/19537/19538

Comment 1: Multiple commenters (16207, 17408, 17620, 17811, 18961, 19536, 19537, 19538) describe the health benefits of the rule, including the $59 billion to $140 billion each year, or $5 to $13 in health benefits for each dollar spent on compliance as opposed to the estimated $10.9 billion annual cost.

Response to Comment 1: The benefits of this rule as estimated by the agency are quite substantial relative to the costs. These benefits include those associated with the estimated Hg reductions as well as the reductions in other pollutants such as fine PM and SO_2. The agency has prepared an extensive analysis of the benefits and costs of this rule which is found in the RIA.

Comment 2: Commenter 16824 considers the potential health benefits of the rule to be questionable because it will have no effect on the levels of Hg and other emissions that occur naturally. The commenter considers the rule to be adversely affecting efforts to stimulate the economy and job growth and causing electric rates to rise.

Response to Comment 2: The agency's analyses of costs and benefits reflect the latest, peer-reviewed science that is available. The benefits analysis is based on peer-reviewed scientific literature, the review of EPA's SAB, and also on the inputs of experts in setting values for benefits for categories such as premature mortality. The benefits estimates reflect the reductions in emissions estimated for this rule, and are incremental to a baseline that includes the impacts of regulatory programs up to December 2010. The agency's cost analyses are also based on peer-reviewed studies and analyses. The RIA for the rule documents both analyses.

Comment 3: Commenter 16850 explains that Florida's investor-owned electric utilities can petition to recover the costs associated with the proposed rule through a cost recovery clause subject to FPSC review. The commenter provides monthly averages for the increase in residential customer costs for every $100 million in environmental compliance costs recovered. These costs range from $1.27 to $10.90 for a 1200 square foot residence. The commenter expresses concern for the Florida consumers, approximately 85% of whom rely on electricity for heating and cooling, and include a large portion of senior citizens on fixed incomes.

Response to Comment 3: The agency estimates that the nationwide retail electricity price increase associated with the rule will be 3.1% in 2015, and there will be some variation in this price increase among different regions. No region of the country, however, is estimated to experience an increase in price of greater than 6.3%. In Florida, the increase in retail electricity price is estimated to be 2.2% in 2015 for the power region that includes the State of FL. State and local rate setting agencies are best equipped to deal with the issues concerning higher electricity rates in their areas.

Comment 4: Commenters 16207 and 17620 discuss health benefits, such as the 6800 to 17000 people saved from premature death, 120,000 prevented asthma attacks, 850,000 employee sick days avoided and the thousands of short and long term jobs created by the rule.

Response to Comment 4: The EPA thanks the commenter for these comments. The benefits of this rule are substantial, both on their own and relative to the costs. The reduction in incidences and how they are estimated can be found in the RIA for the rule. The employment impacts estimated by the agency for the rule reflect both construction labor associated with new control equipment likely to be needed to meet the rule requirements, and operation of these controls, and the reaction of the economy to this rule is also taken into account. The RIA for this rule contains the analysis methodology and results for employment changes.

Comment 5: Commenters 17709 and 17727 express concern about the cost of implementing the proposed rule. The commenters cite an announcement by the American Electric Power company that rates would increase in response to the proposed rule and ask that the proposed rule be reconsidered and implemented with a compliance plan that will allow the utilities to continue operating their coal-fired plants without additional stipulations that will increase rates. Commenter 17709 states that the rule will exacerbate the slow recovery in the state of Michigan.

Response to Comment 5: The agency estimates that the nationwide retail electricity price increase associated with the rule will be 3.1% in 2015, and there will be some variation in this price increase among different regions. No region of the country, however, is estimated to experience an increase in price of greater than 6.3%. The agency is cognizant of the estimated price increases. State and local rate setting agencies are best equipped to deal with the issues concerning higher electricity rates in their areas.

Comment 6: Commenters 17713 and 17766 state that African Americans and Hispanics are worse off than Caucasians by economic measures and tend to be more vulnerable to economic downturns and job losses resulting from EPA regulations. Commenter 17766 explains that 71% of African Americans and 80% of Hispanics live in an area that fails to meet one or more EPA air quality standard, compared to 57% Caucasians. Also, the commenter notes that 68% of African Americans and 39% of Hispanics live within 30 miles of a coal-fired power plant. The commenter states that this close proximity to power plants means that they are more likely to be a risk to develop health issues than those who live in cleaner neighborhoods. The commenter goes on to add that because these same people are more likely to live in poverty, they are less able to move from heavily polluted areas.

Response to Comment 6: We understand the commenters' concerns. The reductions in Hg will lead to improved health in populations in close proximity to coal-fired power plants, and the benefits from these reductions are discussed at length in the RIA for the rule. We show the benefits of Hg and HAP emission reductions, along with the substantial benefits from reductions in emissions of PM, SO_2, and other pollutants in our RIA. Populations that are the focus of EO 12898 (low-income, minority) will benefit from these reductions as shown in the RIA.

Comment 7: Commenter 17775 explains that for EPA benefit estimates to be accurate, up to 20% of annual deaths in large areas of the country were due to ambient $PM_{2.5}$ exposures in 2005. The commenter states that these high assumptions are the result of an assumption change made by the EPA in 2009 to start calculating mortality risk in its risk assessments below the lowest measured levels, which has not been subjected to peer review. The commenter believes this change inflates the baseline of $PM_{2.5}$-related deaths and points out the EPA estimate of deaths among those exposed to $PM_{2.5}$ levels of 12ug/m3 went from almost 3% to nearly 13% as a result of the changed assumption. The commenter calculates that the percentage would be even higher if the higher pollution levels of the past two decades were used. However, the commenter notes that no basis for this change is given. (Footnotes reference Attachment 13 and a June 2010 Qualitative Health Risk Assessment for particulate Matter.)

Response to Comment 7: The EPA disagrees that the method the EPA uses to monetize $PM_{2.5}$ benefits produces unreasonably large estimates. The EPA estimates health benefits below the lowest measured level (LML), as no evidence suggest a health effect threshold for $PM_{2.5}$. These methods have withstood continuous regular reviews by the EPA's SAB. Analyses conducted for the proposed rule demonstrated that the vast majority of $PM_{2.5}$ health benefits occurred above the LML. Therefore, this methodological issue would not have a substantial impact on the overall benefits.

Comment 8: Commenters 17811 and 18436 state that without the proposed rule, "particulate matter emitted directly from coal-fired power plants was estimated to account for an average of $3.7 billion of public health damages each year." The commenters go on to state that the OMB review found that from 10/1/99 to 9/30/09 the cost of a PM rule was $7 billion while the estimated benefits range from $19 billion to $167 billion annually. The commenters state that with few pollutants in the air, healthcare costs will go down. The commenters estimate that the country will save between $13 million and $100 million through reduced premature deaths and healthcare due to illness associated with ozone exposure when the new ozone standards are finalized. The commenters believe that the cost savings of the proposed rule represents economics and fewer children suffering asthma attacks, fewer hospitalizations, less respiratory tract illnesses, improved lung capacity and function for children and healthier infants and newborns. (Footnotes referencing the cited studies may be found in excerpt 11 for commenter 18436.)

Response to Comment 8: The EPA agrees that the large health co-benefits of this rule resulting from $PM_{2.5}$ reductions outweigh the costs.

Comment 9: Commenter 17842 states that the costs associated with the proposed rule will increase costs for North Dakota in the range of 2 to 4 dollars more a month. The commenter is concerned that the estimated costs and affects of the proposed rule do not adequately account for other pending regulations and their collective effect on the industry and economy.

Response to Comment 9: The agency estimates that the nationwide retail electricity price increase associated with the rule will be 3.1% in 2015, and there will be some variation in this price increase among different regions. No region of the country, however, is estimated to experience an increase in price of greater than 6.3%. The agency is cognizant of the estimated price increases. State and local rate setting agencies are best equipped to deal with the issues concerning higher electricity rates in their areas. As to analysis including the effects of pending regulations, the agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: 1) the various EO requirements that the agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; and 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, the EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation. We fold in the impacts of final regulations and other actions into our baseline as appropriate in order calculate the impacts specific to a particular rule as accurately and transparently as possible.

This does not, however, mean EPA has failed to consider cumulative impacts of the regulation. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the broader cumulative impacts of our regulations. In March 2011, the EPA issued the Second Clean Air Act Prospective Report which assessed at the benefits and costs of regulations pursuant to the 1990 CAA Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 CAA Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html.

The direct benefits of the 1990 CAA Amendments and associated programs significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits exceed costs combined with extensive uncertainty analysis suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. This conclusion is likely to also be attributable to this rule as shown in the RIA.

Comment 10: Commenter 17875 states that rules based on peer-reviewed EPA science will prevent illnesses such as asthma attacks and other health and environmental impacts from burning coal, which costs this country upwards of $500 billion each year. Health problems are an especially large burden on uninsured families, the commenter points out, and the groups with the highest rates of asthma are also the least likely to be insured. The commenter adds that history shows that less air pollution means a more efficient workforce and economy, as the EPA estimates the country has gained $21.4 trillion in health and environmental benefits from clean air programs and saved 4.1 million lost work days and 31 million restricted-activity days.

Response to Comment 10: We agree with the commenter on the potential for this rule to reduce incidences of asthma and thus reduce health costs to affected populations. The benefits of these reductions in asthma, along with other benefits, can be found in the RIA for the rule. In addition, we agree that reductions in air pollution can improve worker productivity and health as shown in the Second Clean Air Act Prospective Report released in March 2011 which assessed at the benefits and costs of regulations pursuant to the 1990 CAA Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 CAA Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html.

Comment 11: Commenter 17884 urges the EPA to reconsider the proposed emission standards. The commenter believes the rule, and other recently promulgated rules will decrease the use of coal for electric generation, increase electricity costs by 12-24% in 2016, and cause a net loss of 1.4 million jobs by 2020. The commenter states that this will decrease disposable income that would have been spent on food, clothes, heat and air conditioning, and healthcare. (Commenter provided a bulleted list available in original letter of 8 sets of statistics about different sects of society's income levels and percentage spent on energy costs.) The commenter points out that these increased energy costs endanger public health and welfare because of the correlation between wealth and health. The commenter cites multiple legal cases in which the decision stated the agency must consider safety impacts of regulations. (*Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 496 (2001) (Breyer, concurring), "[p]reindustrial society was not a very healthy society; hence a standard demanding the return of the Stone Age would not prove 'requisite to protect the public health.'" *See* also *Am. Trucking Ass'ns v. EPA*, 175 F.3d 1027,1052 (D.C. Cir. 1999) (EPA must consider whether reducing ozone could have negative health effects), rev'd on other grounds sub nom. *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457 (2001); *CEI v. NHTSA*, 956 F.2d 321, 327 (D.C. Cir. 1992) (agency must consider safety impacts of increasing corporate average fuel economy standards), and refusing to consider the indirect and negative health and welfare impacts entailed by increased regulatory compliance costs. Cf. *International Union v. OSHA*, 938 F.2d 1310, 1326 (D.C. Cir. 1991) (Williams, J., concurring) ("regulation reduces incomes and thus may exact a cost in human lives").] The commenter explains that increased living standards and disposable income mean people can better afford to eat well, heat and cool homes and access healthcare, however, unemployed workers and their families and people living on fixed incomes can least afford the consequences of higher energy costs. The commenter cites Brenner (2002) statistics showing strong research in medical population statistics showing that the higher the social status of a person, the lower the probability of illness and mortality. A quoted study showed that "Assuming costs are distributed proportional to electricity consumption, households with income under $15,000 would incur around 43% of the deaths and households over $50,000 would incur 9% of deaths due to increased energy costs." With unemployment rates at 9.2% and effective unemployment at nearly 20%, the commenter believes the EPA should pursue policies to reduce regulatory burden and create jobs and increased energy costs will lead to job losses and a decrease in general health and welfare. The commenter points out that the EPA's "appropriate and necessary" analysis does not consider the harm to public health that the proposed rule represents, nor does the EPA address the potential health disbenefits. The commenter states that low cost, reliable energy allows people to live longer and better and human health is threatened by the proposed rule.

Response to Comment 11: The agency's final rule establishes emissions standards that require reductions of HAP such as Hg, arsenic, and lead and other metals, among other HAP, that are shown to cause serious injury to exposed populations. We show the benefits of Hg and other HAP emission reductions, along with the substantial benefits from reductions in emissions of PM, SO_2, and other pollutants in our RIA. Populations that are the focus of EO 12898 will benefit from these reductions as shown in the RIA. In addition, the increase in electric rates to consumers as shown in the RIA will be 3.1% on average nationally by 2015, with some consumers in certain regions seeing increases of 6.3% while other consumers in different regions will see increases of only 1.3%. These increases in electric rates may not be minimal in some areas of the U.S., but they should be seen in light of the substantial benefits to health from the emission reductions that will take place across the country due to this rule.

The agency did not prepare a cumulative impact analysis for the rule for the following reasons: 1) the various EO requirements that the agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; and 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, the EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation.

This does not, however, mean EPA has failed to consider cumulative impacts of the regulation. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the broader cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed at the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html.

The direct benefits of the 1990 Clean Air Act Amendments and associated programs significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits exceed costs combined with extensive uncertainty analysis suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. This conclusion is likely to also be attributable to this rule as shown in the RIA.

Comment 12: Commenter 11107 submits an op-ed which must be viewed at http://www.buffalonews.com/editorial-page/viewpoints/article429987.ece due to copywrite restrictions. The commenter states that money can be saved by improving air quality and cites (along with commenter 17408) the National Research Council report that says hidden costs of burning coal were $62 to $156 million for each coal plant. These costs are largely due to SO_2 emission. The commenter also cites a study which estimates emission-related damages from coal-fired power plants to be between $0.02 and $1.57 per kWh generated.

Response to Comment 12: The EPA thanks the commenter for the comments. The agency estimates substantial benefits from the reduction of HAP and other pollutants from power plants as a result of this rule, and these results are presented in the RIA for the rule. What the agency describes as "benefits" are similar to the health and other costs described by the commenter.

Comment 13: Commenter 17254 states that removal of air pollutants will improve air quality and public health of Georgia communities and cited 79,383 cases of asthma in Fulton County, GA, which earned a grade of F for the American Lung Association's state of the air report. The commenter expects these numbers to increase costs to families, communities and tax payers without more air pollution regulation. The commenter cites Clean Air Task Force as claiming 1,224 deaths caused by local coal-fired power plants, along with 1,710 heart attacks, 1,770 asthma attacks and 752 cases of chronic bronchitis per year, at a cost of over $9 billion. The commenter also cited the National Academy of Sciences as saying that SO_2, NO_X and PM emissions from coal-fired power plants account for $62 billion in economic damages in 2005.

Response to Comment 13: The agency expects that the benefits of this rule to Fulton County, GA to be large, though we have not quantified the impact to this county specifically (it is included in our benefits analyses in our RIA, of course). The benefits from reductions of HAP and other pollutants due to this rule will be $37 to $90 billion using a 3% discount rate or $33 to $81 billion using a 7% discount rate (2007 dollars) in 2015, and this is substantial on its own and relative to the costs of the rule ($9.6 billion in 2015, in 2007 dollars).

Comment 14: Commenter 17408 discusses the Fisk and Crawford coal-fired power plants in Chicago. The commenter says the Fisk plant was built in 1903 and rebuilt in 1959. The newest turbines at the Crawford plant were installed in 1958 and 1961. The commenter says that pollution from these two plants cost neighboring communities $127 million annually in health damages, according to the October 2011 report by Environmental Law and Policy Center. The commenter went on to cite the Natural Resources Defense Council studies that have shown a high benefit to cost ration from environmental regulations, with saving in health costs alone surpassing the cost of pollution controls or switching to cleaner energy sources. The commenter acknowledges that some jobs will be lost, but also created with the proposed rule. The commenter cites Jonathan Levy's Harvard report which states that 200 lives could be saved in the Chicago area if pollution were better controlled. The commenter believes that industry must invest in pollution control because it is a fair cost of doing business. The commenter points out that healthcare costs are being unfairly transferred to people who may not have insurance and in the state of Iowa almost two-thirds of children live within 30 minutes of a coal-fired power plant.

Response to Comment 14: The EPA thanks the commenter for their comments. The agency expects substantial benefits to Chicago and Iowa residents as a result of this rule as HAP and other pollutants are reduced significantly. Estimates of pollution reduction and associated benefits can be found in the RIA for the rule. In addition, there may be a small net gain in employment nationally associated with this rule as shown in the RIA.

Comment 15: Commenter 17409 questions the use of a 7% discount rate for overall benefits. The commenter sees a discount rate that high as meaning that future benefits lose half their value every 10 years. Because the benefits in question are the health and wellbeing of children, the discount rate means the worth of children decreases by half every 10 years. The commenter suggests that when calculating for generational benefits, the EPA should use a 2.5% discount rate as used when dealing with climate change.

Response to Comment 15: The preferred discount rate for benefits estimation by the agency is 3%, not 7%. This is explained in the RIA for the rule, where the benefits analysis for this rule is presented. Estimates of benefits with a 7% discount rate are prepared in adherence to OMB Circular A-4, which we must follow in preparing the RIA for a rule such as this one, and that calls for presentation of costs and benefits discounted at both 3 and 7% rates.

Comment 16: Commenter 17409 states that the cost of pollution is being borne by children and other vulnerable people and reports that 1 in 11 children has asthma, resulting in a $56 billion expenditure making it so that we can't afford not to clean our air. The commenter goes on to discuss the B.L. England plant, which produces 29 pounds of Hg annually and is built on a bay. The commenter states that 1/70 of a teaspoon of mercury is enough to contaminate a 25 acre lake. The commenter also cites the February 2011 Harvard Medical Study showing public health costs related to coal are a $175 to $500 billion annually.

Response to Comment 16: The EPA thanks the commenter for the comment. We agree that polluted air can impose detrimental health outcomes such as asthma or other ailments, and the reductions of HAP and other pollutants associated with this rule will lead to improved public health and thus reduced health costs for asthma sufferers. In addition, reductions in Hg will also improve health and ecosystems, as the agency shows in the RIA for this rule.

Comment 17: Commenter 18432 supports the proposed standards as fair and equitable and believes communities will benefit from the reduction in air pollution no matter if the regulated facilities choose to add pollution controls, switch fuels or shut down and pursue renewable energy sources.

Response to Comment 17: We agree with the commenter that the pollutant reductions from this rule will be fair and equitable to the extent we can require them, and do agree that the benefits of the rule will be large regardless of how the reductions are obtained. However, we are mindful of the need to minimize the economic impacts and costs of this rule along with the need to maximize benefits when permissible under the CAA.

Comment 18: Several commenters (18432, 18435, 18541) urge the EPA to proceed with finalizing the proposed rule without changing it, as it will prevent more Americans and especially children from premature death or chronic illness.

Response to Comment 18: The EPA thanks the commenter for their comments. We have reviewed public comments on the proposed rule as required by law and issued this final rule in light after considering and responding to such comments.

Comment 19: Multiple commenters (18541, 19536, 19537, 19538) say that the full cost of the regulated pollutants is not adequately reflected in electricity costs or the cost-benefit analyses. The commenters state that the cost of the pollution emitted by EGUs is being unfairly placed on the public instead of the polluting source. The commenters considered the EPA analyses insufficient because they do not assess impacts on wildlife and ecosystems, as they should be under the Biological Assessment, ESA and CAA. The commenters urge that analysis be broadened to include valuation of these impacts, even if the studies are limited.

Response to Comment 19: The agency recognizes the need to include the effects on wildlife and ecosystems in the benefits analyses for our rules. We include these benefits to the extent that it is credibly possible according to our understanding of the relevant science in our analyses, and this is shown in the RIA for this rule.

Comment 20: Commenter 18961 cites a recent study by the United Nations Environment Program which estimated that a reduction by at least 50% of Hg emissions from current levels provides societal benefits more than double the implementation cost by the year 2020. The commenter reports that the estimate is based on the value of averting human neurotoxic damage, loss of earnings, loss of education and opportunity costs. The report showed that even a reduction of 30 to 50% would produce benefits beyond the costs.

Response to Comment 20: The EPA thanks the commenter for their comments on Hg benefits. Our current estimate of Hg benefits for this rule is $4 to 6 million using a 3% discount rate and $0.5 to $1 million using a 7% discount rate (2007 dollars) annually in 2015 as shown in the RIA for the rule. We intend to refine our estimates of Hg benefits over time and given the availability of new studies. This rule as a whole will provide substantial benefits based on the expected reduction in reductions of HAP such as Hg and other pollutants.

Comment 21: Several commenters (19536, 19537, 19538) report that the Minnesota Pollution Control Agency and Legislative Commission on Minnesota Resources estimate the economic benefits of reduced Hg at $212 million based on 50% reduction. This study understates the total economic benefits, according to the commenter, because it does not take into account factors such as improved public health. Commenters also quote the Harvard School of Public Health estimate that health related economic impact of Hg pollution exceeds $5.5 billion and estimates the costs of lost productivity due to reduced IQs from Hg pollution at $1.625 billion, the costs of mental retardation due to Hg emission at $361 million and the cost of excess cardiovascular disease from Hg exposure at $3.54 billion.

Commenters state that a decline in angling of just 25% due to lake and stream fouling by Hg could cost Minnesota $706 million annually and jeopardize 25,955 jobs in the state. In Wisconsin, the costs of water fouling from Hg could cost $516 million annually and jeopardize 21,459 jobs. Commenters believe the proposed rule will help improve regional haze and sulfate deposition, lessen acidification of lakes and streams and decrease concentrations of lung damage due to air pollution.

Response to Comment 21: The EPA thanks the commenters for the results of these studies, and agrees in general with the commenters' conclusions on reduced regional haze, sulfate deposition and lake deacidification, and improved human health related to the reduction of HAP and other pollutants related to this rule. For more information on these types of impacts and how the agency's benefits analysis considered them, refer to the RIA for the rule.

6K - Impacts/Costs: Health Co-Benefits

Commenters: 12267, 14115, 15002, 16404, 16469, 16630, 16826, 16849, 17157, 17254, 17283, 17381, 17408, 17409, 17620, 17621, 17623, 17637, 17638, 17639, 17648, 17676, 17681, 17689, 17702, 17707, 17709, 17715, 17716, 17718, 17727, 17730, 17731, 17734, 17736, 17751, 17753, 17754, 17755, 17756, 17757, 17761, 17765, 17766, 17775, 17799, 17800, 17805, 17811, 17813, 17816, 17843, 17848, 17852, 17855, 17868, 17871, 17875, 17880, 17882, 17884, 17903, 17912, 17916, 17919, 17921, 17930, 17931, 18018, 18022, 18027, 18029, 18033, 18034, 18037, 18039, 18421, 18425, 18428, 18432, 18435, 18436, 18438, 18477, 18478, 18487, 18488, 18498, 18500, 18501, 18502, 18541, 18759, 18961, 18963, 19114, 19121, 19145, 19580, 19536/19537/19538, 18932, 18023

1. Benefits of the proposed rule outweigh compliance costs.

Comment 1: Several commenters (15002, 17648, 17921, 18541) agree with the EPA that health benefits of the proposed rule far outweigh the costs incurred by industries to comply. Commenters 15002 and 17468 suggest that the estimates of benefits are underestimated due to the lack of quantification of benefits due to expected reductions in ground-level ozone. Commenter 17648 argues that the EPA employed peer-reviewed and conservative methodology in preparing the benefit-cost analysis, and argues that even without the rule, the development of stable and lower-priced natural gas supplies will result in the closure of obsolete coal plants. Commenter 17648 further states that critics of the EPA's benefit-cost analysis do not understand the principles of economic impact analysis. The commenter states that despite criticism, the inclusion of $PM_{2.5}$ co-benefits as part of the monetized benefits are appropriate because HAP are part of the $PM_{2.5}$ fraction. Commenter 15002 points out that recent data estimate that almost 120 Americans live in counties where NAAQS are not met, though the commenter considers these standards insufficient to protect health. Commenter 15002 further notes that $PM_{2.5}$ reduction is projected to occur as the result of improved trapping of primary particulates and formation of secondary particulates created by condensation of oxides of sulfur and nitrogen with other chemicals or particles in the atmosphere. According to the commenter, these reductions are expected to result in a substantial reduction in several diseases, and improve overall mortality. Commenter 17648 points out several benefits not quantified by the EPA, such as (1) young women who now avoid eating fish due to concerns of Hg; (2) reductions in synergistic and additive effects of the pollutants whose emissions will be reduced; (3) enhanced ecosystem services; (4) reduced acidification of ecosystems; (5) elimination or reduction of a variety of unquantified health impacts, including respiratory effects, resulting in increased hospital and emergency room visits, respiratory symptoms, airway hyper-responsiveness, airway inflammation and lung function; (6) reduction of impacts of heavy metals; and (7) secondary impacts such as economic benefits to downwind businesses. Commenter 17921 recommends two studies regarding the benefits of reducing Hg emissions that could be used to better estimate health benefits of the rule: (1) Rice, G., & Hammitt, J. K. (2005). *Economic valuation of human health benefits of controlling mercury emissions from U.S. coal-fired power plants;* and(2) Trasande, L., Landrigan, P. J., & Schechter, C. (2005). Public health and economic consequences of methylmercury toxicity to the developing brain. *Environmental Health Perspectives*. doi: 10.1289/ehp.7743. Commenter 18541 argues that the benefits to wildlife were not fully accounted for, saying that the EPA should formally consult the U.S. Fish and Wildlife Service and the National Marine Fisheries Service to set the standards strictly enough to protect wildlife and ecosystem health. Commenter 17648 suggests that the agency overestimated the costs of compliance, partly due to technological innovation that is not considered. The commenter provides the example of the acid rain program, in which according to the RIA, the cost of implementing the program was 83% lower than original estimates.

Response to Comment 1: This rule is expected to achieve important non-Hg HAP benefits. However, monetization of non-Hg HAP benefits is limited by currently available data and methods. In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAP anticipated to be reduced by these rules. The EPA disagrees that the health benefits of non-Hg HAP could never be measured. A well designed epidemiological study could measure these benefits. The EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk. Quantitative estimates of these benefits are provided to the extent possible, and our limited ability to monetize these benefits does not indicate that they are non-existent or less important.

Our treatment of these benefits follows guidance set by OMB Circular A-4 (pp. 26-27, available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/):

"Sound quantitative estimates of benefits and costs, where feasible, are preferable to qualitative descriptions of benefits and costs because they help decision makers understand the magnitudes of the effects of alternative actions. However, some important benefits and costs (e.g., privacy protection) may be inherently too difficult to quantify or monetize given current data and methods. You should carry out a careful evaluation of non-quantified benefits and costs. Some authoritiesrefer to these non-monetized and non-quantified effects as "intangible.""

It is also in line with EPA's Guidelines for Preparing Economic Analyses (p. 11-3, available at: http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html).

"Benefits and costs that cannot be monetized should, if possible, be quantified (e.g., expected number of adverse health effects avoided). Benefits and costs that cannot be quantified should be presented qualitatively (e.g., directional impacts on relevant variables)."

2. Benefits of the proposed rule do not outweigh compliance costs.

Comment 2: Many commenters (14115, 16469, 17638, 17639, 17681, 17702, 17716, 17730, 17731, 17751, 17753, 17754, 17756, 17757, 17761, 17765, 17799, 17800, 17813, 17855, 17868, 17884, 17919, 17930, 17931, 18033, 18034, 18037, 18428, 18488, 18963, 19121, 19580, 18023) suggest that the benefits of the proposed rule do not outweigh the cost. Multiple commenters (14115, 16469, 17638, 17681, 17702, 17716, 17730, 17731, 17751, 17754, 17757, 17761, 17765, 17800, 17813, 17855, 17868, 17930, 18033, 18034, 18037, 18428, 18488, 18023) state that most of the benefits would be due to $PM_{2.5}$ co-benefits, and that the Hg benefits would amount to \$6 million or less, far below the estimated \$10.9 billion annual costs. Commenter 18037 states that regulations focus on incrementally smaller emission reductions and with increased costs, and thus regulations are less and less justified. Several commenters (17639, 17799, 17912) state that the benefits of the proposed rule do not justify the costs since the predicted risks for air toxins are approaching or are less than 1 in 1 million and fine particulate matter is regulated under the ambient air quality standards of the CAA. Commenter 17799 argues that the analysis of chromium emissions was flawed, in that hexavalent chromium, a carcinogen, may be converted to less toxic forms by the time it reaches the target population; thus the corresponding increased cancer risk from 0.33 (lifetime cancer risk to average person) to 0.330001 "is so minimal that it could not be observed in any health effects study that might be conducted." Similarly, commenter

18034 states that the cancer risks from nickel and hexavalent chromium emissions are within limits previously considered acceptable by the EPA. Commenter 17799 also points out that the "EPA states that non-cancer risks for the non-mercury HAP for coal units never exceeded a non-cancer hazard index of 0.5 whereas the level of concern would be 1.0...[the EPA's definition of hazard index states that] exposures equal to or below [a hazard index] of 1.0...likely will not result in adverse non-cancer health effects over a lifetime of exposure and would ordinarily be considered acceptable." Several commenters (17639, 17754, 17757) point out that the proposed rule duplicates existing regulations and will exhaust state and federal government resources.

Response to Comment 2: The EPA disagrees with commenters that the benefits of the rule do not exceed the costs. The benefits of this rule encompass the benefits of Hg reductions and co-benefits to health achieved via $PM_{2.5}$ reductions. As the analyses presented in the RIA for the rule show, the benefits outweigh the costs by a large margin. Although the monetized benefits of reducing Hg emissions are not large, those benefits are also not equally distributed across the population. As the sensitivity analysis shows, some populations, including low-income African Americans and some Native American populations, may receive a disproportionate benefit, and the distributional aspects of the benefits may help to justify the costs of the rule. Furthermore the analysis depended on using a less sensitive endpoint (IQ) of neurological impacts of Hg exposure as noted by the SAB which leads to underestimation of the benefits. Additionally many other impacts of Hg emissions were not quantified including impacts on ecosystems and wildlife especially fish, birds both fish and insect eating, and mammals. Other HAP controlled by the MATS rule were likewise not quantified due to data, resource and methodological limitations. Even if we were able to fully monetize the public health benefits of reducing exposure to Hg and other HAP, it is likely that the PM benefits would continue to dominate the total monetized benefits due to the size of the exposed population and the severity of the associated health effects. Despite our inability to provide monetized benefits of HAP emission reductions, the total monetized benefits exceed the estimated costs of the rule by a substantial margin, even when taking uncertainty into account.

Consideration of $PM_{2.5}$ health co-benefits expected as a result of direct $PM_{2.5}$ and SO_2 emission reductions is directed by OMB Circular A-4 (p. 26, available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/):

"Your analysis should look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks. An ancillary benefit is a favorable impact of the rule that is typically unrelated or secondary to the statutory purpose of the rulemaking (e.g., reduced refinery emissions due to more stringent fuel economy standards for light trucks) while a countervailing risk is an adverse economic, health, safety, or environmental consequence that occurs due to a rule and is not already accounted for in the direct cost of the rule (e.g., adverse safety impacts from more stringent fuel-economy standards for light trucks)."

It is also directed by the EPA's Guidelines for Preparation of Economic Analyses (p. 11-2, available at: http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html):

"An economic analysis of regulatory or policy options should present all identifiable costs and benefits that are incremental to the regulation or policy under consideration. These should include directly intended effects and associated costs, as well as ancillary (or co-) benefits and costs."

In line with this guidance, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible. We further note that if we were able to fully monetize all of the benefit categories, the benefits would exceed the costs by an even greater amount than we currently estimate.

3. Methods used to calculate benefits.

Comment 3: Several commenters (17623, 17639, 17799, 18428, 18963) suggest the EPA is overestimating the benefits of Hg emission reductions associated with the rule. Commenters 17623 and 18963 state that recent estimates of emissions from coal-fired units show a substantial reduction in Hg from 2000 to present. Commenters 17639 and 17799 quote a risk science consulting firm statement that the health benefits attained by Hg reductions could "never be measured or observed in real life." Commenter 17799 argues further that the "public health benefits from HAP reductions are minimal," stating that the rule would have a negligible impact on mercury exposures in most of the U.S. because Hg exposures are dominated by non-U.S. sources. Commenter 18428 suggests that the improvement of 500 IQ points across the entire U.S. population estimated in the benefits calculations is negligible and should not be considered. Similarly, commenter 17623 states that for Hg, some of the EPA's health effects could not be monetized, such as IQ improvements. Commenter 17799 states that the EPA attempts to justify regulation of non-Hg HAP based on environmental benefits, which is "not a criterion Congress gave EPA as a basis for regulation under 112(n)(1)(A) and therefore is an irrelevant consideration."

Response to Comment 3: The EPA disagrees with commenters that the benefits of Hg emission reductions associated with this rule were overestimated. In fact, the EPA believes that the estimates presented in the RIA are an underestimate because the EPA was not able to analyze the impacts using the most sensitive endpoints for human health. According to the SAB's review of the TSD for this rule "The loss of IQ points is likely to underestimate the impact of reducing methyl mercury in water bodies. The reason is that IQ score has not been the most sensitive indicator of methylmercury's neurotoxicity in the populations studied. As noted in the TSD, in the Faroe Island study the most sensitive indicators were in the domains of language (Boston Naming), attention (continuous performance) and memory (California Verbal Learning Test), neuropsychological tests that are not subtests of IQ tests and are not highly correlated with global IQ. In the Seychelles study, the Psychomotor Development Index has been most sensitive measure and, while this is a component of the Bailey Scales of Infant Development, it is not highly correlated with cognitive measures."

The EPA also would point out that the estimates only use self-caught freshwater fish, including saltwater fish consumption would increase the estimates. In addition many of the benefits of Hg reductions were not quantified including the many significant adverse impacts to wildlife and ecosystems.

Comment 4: Several commenters (17702, 17751, 18018, 18033, 18500) express concerns that the method the EPA used to monetize benefits produces unreasonably large estimates. Commenter 18033 cites the EPA's counting of mortality estimates for $PM_{2.5}$ exposures below the lowest measured level (LML) as a major concern. Commenter 18033 points out that the EPA has never set a NAAQS at a level as low as the LML because the EPA believed that it was not required to protect public health; however, the commenter argues that using the LML in this rule drastically overestimates mortality associated with low levels of $PM_{2.5}$.

For several commenters (17702, 18018, 18500), the specific concern is that using the value of statistical life (VSL) based on the public's willingness to pay (WTP) results in a VSL of $8 million per person. The VSL is used regardless of the time a death is postponed, while the annual value for GDP per person is around $42,000. Commenters point out that even if the death is postponed for 10 years by the proposed rule, the GDP value would be around 5% of the EPA VSL. Commenter 18018 discusses calculating the VSL to estimate the value of remaining life, so that a 2-year-old would have a higher VSL than an 80-year-old, since people with shorter life expectancy may be less willing to devote resources to reduce their risk of premature death. Commenter 17751 states that the mortality risk reduction is derived from a meta-analysis of 26 contingent valuation and labor market studies from 1982 to 1991, but does not adequately discuss the need to improve WTP valuations or present limitations of the estimate. For example, commenter 17751 points out that the EPA does not cite studies critical of the meta-analysis or the fact that many labor market studies in the meta-analysis reflect wage differentials which arise from differences between occupations in terms of risk of death in accidents. Commenter 17751 questions the EPA's lack of consideration of whether to apply values derived from contexts in which risk is immediate to environmental policy context in which risk involves long-term consideration. Commenter 17751 also points out the lack of consideration of the importance of selection bias in the meta-analysis. Commenter 17751 states that the EPA's chosen value for mortality risk reduction is based on an average of findings, but the studies are not a random sample of studies but rather those selected by the analysis author to satisfy certain criteria not revealed. The commenter further states that in comparison to the EPA's simple average of 26 studies that yielded a value of $6.2 million (2000 dollars), one comparative study (Giles, et al.) found that correction for publication selection bias yielded a value of $2.74 million (2000 dollars). The commenter requests that the EPA include a discussion of alternative meta-analyses of WTP studies. The commenter recommends the following:

1. Bellavance, F., Dionne, G., Lebeau, M. 2009. The Value of a Statistical Life: A meta-analysis with a mixed effects regression model. Journal of Health Economics 28: 444-464.
2. Bowland, B.J., Beghin, J.C. 2001. Robust Estimates of the Value of a Statistical Life for Developing Countries. Journal of Policy Modeling 23: 385-396.
3. De Blaeij, A., Florax, R.J.G.M., Rietveld, P., Verhoef, E. 2003. The Value of Statistical Lifein Road Safety: A meta-analysis. Accident Analysis andPrevention35: 973-986.
4. Dionne, G., Michaud, P.C. 2002. Statistical analysis of value-of-life estimates using hedonic wage method. Working Paper 02-01. Risk Management Chair, HEC Montréal.
5. Kochi, I., Hubbell, B., Kramer, R. 2006. An Empirical Bayes Approach to Combining and Comparing Estimates of the Value of a Statistical Life for Environmental PolicyAnalysis**.** Environmental and Resource Economics 34:385-406
6. Lindhjem, H., Navrud, S., Braathen, N.A. 2010. Valuing Lives Saved From Environmental, Transport and Health Policies: A meta-analysis of stated preference studies. Working Party on National Environmental Policies, OECD, February.
7. Liu, J.T., Hammitt, J.K., Liu, J.L. 1997. Estimated Hedonic Wage Functions and Value of Statistical Life in a Developing Country. Economics Letters 57(3):353-358.
8. Miller, T.R. 2000. Variations Between Countries in Values of Statistical Life, Journal of Transport Economics and Policy 34(2): 169-188.
9. Giles, Doucouliagos and Stanley have statistically assessed the effect of selection bias on meta-analyses of the value of mortality risk reduction, and have found that correction for selection bias reduces the average value by 70 to 80 %.

Response to Comment 4: The EPA disagrees with commenters that the method the EPA uses to monetize $PM_{2.5}$ benefits produces unreasonably large estimates. The EPA estimates health impacts of $PM_{2.5}$ below the LML, as evidence suggests that there is no discernable threshold for long-term $PM_{2.5}$ mortality (e.g., Roman et al. 2008, Schwartz et al. 2008, Krewski et al. 2009). The EPA methods for quantifying health benefits of emission reductions are based on the best available peer-reviewed science and methods that have withstood scrutiny from the EPA's independent SAB, the National Academy of Sciences, and continuous interagency review. Note that NAAQS are set at a level deemed by the EPA

Administrator to be protective of public health within an adequate margin of safety, and are not set at a level of zero risk. Further, analyses conducted for the proposed rule demonstrated that while 30% occur above the LML (10 ug/m3) of the Laden et al. (2006) study, 86% of PM2.5 health benefits occurred above the LML (7.5 ug/m3) of the Pope et al. (2002) study. We note that a more recent extended re-analysis of the Pope et al. (2002) study found significant health impacts of $PM_{2.5}$ down to a lower LML (5.8 ug/m3; Krewski et al. 2009). Therefore, we believe estimation of health effects below the LMLs in the Laden et al. (2006) and Pope et al. (2002) study is justified. However, we do note that as we model mortality impacts among populations exposed to levels of $PM_{2.5}$ that are successively lower than the LML of each study our confidence in the results diminishes. Therefore, we continue to include statistics in the final RIA (as was done in the RIA for the proposed rule) showing the percentage of health impacts occurring above these levels for readers to understand the effect of this methodological decision.

With respect to the method the EPA uses to monetize benefits, according to standard welfare economics, the economic value of a reduction in mortality risk is the maximum amount an individual would be willing to pay for it. The VSL is a representation of WTP values in that it captures the average rate at which people are willing to pay for very small changes in mortality risks (say, 1 in 10,000 per year). The VSL does not represent the value of avoiding or postponing certain death for any particular individual. By convention, estimates of these willingness-to-pay values are typically normalized by the change in risk. For example, if on average workers are willing to sacrifice $800 in additional annual pay for jobs that have a reduced fatality risk of 1 in 10,000 per year, then the estimated VSL would be $800 × 10,000 = $8 million. The estimated annual WTP per exposed individual for the average risk reduction under this rule is well below the annual value for GDP per person of $42,000.

On calculating VSL to estimate the value of remaining life, the EPA has explored the issue of remaining life expectancy and its potential effect on WTP in the past and has, in fact, received guidance from the SAB on the matter. The SAB's full response is available in their October 12, 2007 guidance to the EPA on valuing mortality risk reductions, pages D-10 and D-11. To summarize, the SAB points out that economic theory is ambiguous on how people's willingness to pay to reduce mortality risks should change over their lifetime, leaving it, therefore, as an empirical matter. The judgment of the SAB, however, is that the empirical literature is not advanced enough to provide clear guidance on how age and health status affect willingness to pay to reduce mortality risks. The recommendation of the SAB is to use an age-independent valuation of mortality risk reductions. .http://yosemite.epa.gov/sab/sabproduct.nsf/02ad90b136fc21ef85256eba00436459/4128007E7876B8F085257376005 8A978/$File/sab-08-001.pdf

Regarding the limitations of WTP, the 26 studies underlying the EPA's guidance for WTP for mortality risk reductions come from Viscusi, 1992, which describes the selection criteria. Viscusi, 1992, is described as the source for these studies when the EPA originally used the set in The Benefits and Costs of the Clean Air Act: 1970 to 1990 (US EPA, 1997, page I-3). Most of the studies in this set of literature are based on wage differentials for workplace risks. Although these estimates cannot be taken as precise values for mortality risk reductions from environmental policies, their usefulness for informing environmental policy analysis has been recognized by the Environmental Economics Advisory Committee of EPA's SAB (SAB-EEAC) (US EPA SAB 2000). The difficulties and limitations of these estimates for environmental policy are described in our *Guidelines for Preparing Economic Analyses* (US EPA 2010).

The agency has examined multiple meta-analyses published in the economics literature since promulgating our guidance in the *Guidelines for Preparing Economic Analyses* in 2000. This effort includes a report from leading experts in statistical meta-analysis (USEPA 2006). The agency has consulted with the SAB-EEAC on how to evaluate and apply meta-analyses, and how the agency should revise its own meta-analysis methodology. Although the SAB-EEAC did not recommend that the EPA adopt any of the existing meta-analyses, the Committee made several recommendations on how the agency should conduct its own analysis, including details on selection criteria, and how to incorporate results from different methods and in different contexts (US EPA SAB 2007, 2011). Based on these advisories the EPA is now reviewing the existing literature and developing methods to inform new guidance on valuing reductions in mortality risks in agency economic analyses. This effort will include considerations of many potential biases in the resulting estimates, including issues such as the publication bias concern described in the Giles, et al. study.

Comment 5: Several commenters (16469, 18500, 17621, 17283) suggest that the uncertainty analysis is insufficient. Commenter 17621 argues that "the only quantitative uncertainties presented are those for the particular dose-response estimates taken from the two studies cited by EPA. Other uncertainties are listed in several tables, with no attempt to quantify them." Several commenters (16469, 17621, 17283, 18500) suggest that the differential toxicity of PM species needs to be considered when calculating potential health benefits of emissions reductions to fully assess the impacts, and this issue should be considered in the uncertainty analyses.

Response to Comment 5: The EPA disagrees with these commenters that the uncertainty analysis is insufficient. We conduct several different types of analyses that examine the effects of the most important methodological choices on results. For example, we estimate mortality impacts using health effect estimates garnered from an EPA-sponsored expert elicitation (Roman et al. 2008). The experts in the elicitation produced a range of effect estimates that span from smaller than the effect estimate by Pope et al. (2002) and larger than the effect estimate by Laden et al. (2006). The expert elicitation is one method of characterizing uncertainty in PM-related mortality. Although we are unable to quantify the impact of all sources of uncertainty, we examine the effect of assuming a health effect threshold at the lowest measured level in the epidemiology studies. We also conduct sensitivity analyses examining different income elasticity assumptions. The uncertainties that are not quantifiable are listed in tables to acknowledge their possible influence on estimated benefits.

4. Criteria co-benefits should not be considered in analysis.

Comment 6: Many commenters (17702, 17716, 17751, 17753, 17754, 17765, 17775, 17799, 17813, 17855, 17912, 17919, 18034, 18428, 18488, 18498, 18963, 19114, 18023) question the use of criteria co-benefits to justify HAP regulation. They suggest that the inclusion of co-benefits is contrary to the original intention of reducing Hg emissions, because the reductions of $PM_{2.5}$ emissions can be expected to be achieved through other regulations. Commenter 17765 states that the little incremental health benefits from the proposed rule do not justify its economic impacts. Commenter 17716 estimates that without co-benefits, the "net benefits" of the proposed rule would be negative $42,000,000,000 to negative $130,000,000,000. Commenters 17716 and 17799 question the intent of the CAA or legislative history to have co-benefits from criteria pollutants regulated under a different CAA regulatory scheme serve as the driving force to curb HAP emissions through MACT regulation. Commenters 17754 and 18034 acknowledge that benefits beyond those from Hg emissions reductions will be up to $130 billion annually, but again, since these benefits come from co-benefits from reducing $PM_{2.5}$ emissions, consider the cost-benefit analysis supporting regulation of Hg emission to be flawed. Commenter 17775 attached a memo by Dr. Anne Smith providing technical comments on the RIA for the proposed rule and discussing the use of co-benefits. The commenter states that $PM_{2.5}$ benefits are attributable to the control of HAP acid gases, yet public exposures to HAP acid gas emissions were found to be far below the reference concentration levels for those HAP, which the EPA defines as being without an appreciable risk. Commenters 17912 and 17919 question the EPA's legal justification for the proposed rule that argues non-Hg HAP must be regulated. Commenter 17719 points out that there is a separate program for the regulation of $PM_{2.5}$, and the EPA does not address whether there is a less expensive way to achieve the same benefits attributed to the proposed rule, such as those included in the $PM_{2.5}$ program. Commenter 17719 believes this is pertinent, since the EPA is mandated to find the most cost effective solution for regulatory priority.

Multiple commenters (18023, 16469, 17621, 17718, 17751, 17761, 17800, 17816, 17919, 17855, 18033, 18963) find the EPA calculation of $PM_{2.5}$ NAAQS benefits to be incorrect because the commenters say the EPA is either double counting potential benefits of the NAAQS program in the calculation of benefits from the proposed rule, or relying on the supposition of health benefits from any PM reduction anywhere. Commenter 18023 considers this an unfounded supposition that both the EPA and the EPA science advisors have rejected as too uncertain to adopt when setting $PM_{2.5}$ NAAQS. Commenter 18023 points out that if these $PM_{2.5}$ benefits are disregarded, the monetized benefits for the proposed rule drop to \$0.576 billion, from CO_2 reductions and HAP reductions. The commenter states that this change means the cost of the proposed rule would exceed the monetized HAP benefits by a factor of at least 1,800.

Comment 7: Numerous commenters (16469, 16849, 17638, 17681, 17702, 17730, 17799, 17848, 17919, 18018, 18033, 18500, 18023) estimate that 90-99% of the benefits the EPA attributes to the proposed rule actually come from $PM_{2.5}$ reductions from reduced emissions of SO_2, which is not a HAP, and did not indicate benefits from acid gas reductions. Commenters believe the same benefits would be delivered by other CAA rulemakings including PM, SO_2 and ozone NAAQS and the Cross-State Air Pollution rule. Commenter 16849 points out the limitations of the proposed solutions due to the fact that multiple emission control equipment do not always work together harmoniously following a retrofit. Commenter 17702 believes that proposing air toxic limits more restrictive than those envisioned under CAMR would result in greater costs without commensurate benefits to the public. Commenter 17730 believes the proposed rule should be based on the rule's ability to reduce the emissions of HAP that provide a public health benefit after imposition of the CAA requirements and the associated public health and environmental benefits from those reductions. Commenter 17848 points out that the estimated health benefits from the proposed rule were compared with the estimated health benefits from the Transport Rule SO_2 reductions and the number of avoided outcomes per 1,000 tons of SO_2 reduction is nearly identical for 2014 and 2016. However, the commenter points out that ambient $PM_{2.5}$ levels should decrease between those 2 years as a result of the Transport Rule reductions. Therefore the commenter says that since baseline emissions should be lower after Transport Rule implementation, a smaller quantity of SO_2 reductions would be achieved by the proposed rule. Several commenters (18023, 17638, 17681) state that over 80% of the estimated $PM_{2.5}$ health benefits are assumed to occur in areas that meet the levels the EPA is currently considering for a new $PM_{2.5}$ NAAQS, and thus should not be considered under this rule. Commenter 18500 cautions that the EPA's monetizing benefits estimate due to CO_2 reductions should be considered carefully because a of the questions associated with climate change.

Comment 8: Many commenters (16469, 17621, 17623, 17637, 17681, 17702, 17751, 17761, 17775, 17800, 17855, 17884, 17919, 18033, 18963, 18023) note that the $PM_{2.5}$ co-benefits to which many of the proposed rule's benefits are attributed are mainly based on emission reductions in areas already achieving the annual $PM_{2.5}$ NAAQS or are being addressed by other rules. As such, commenters 17623 and 17855 ask that the EPA explain what additional PM benefits are derived from the proposed rule. Commenter 17681 considers the costs of the proposed rule to be very low and not outweighed by the "contrived" benefits. Commenters 17919 and 18023 state that the NAAQS set a level of $PM_{2.5}$ that the

EPA found to be sufficient to public health and welfare with an adequate margin of safety and areas in attainment with this level are already safe from health risks. Some commenters (17855, 17621, 17637, 17718, 17761, 18963) state that attainment of the NAAQS for $PM_{2.5}$ is already being addressed on both the local and regional basis through SIPs and CSAPR. Commenter 18033 points out that the EPA "is preparing to propose a new [lower] $PM_{2.5}$ NAAQS...[but] until it does so...it is inappropriate for EPA to adopt rules based on claimed benefits below the current NAAQS level." Commenter 17621 requests that the EPA clearly articulate the individual benefits to all of its pending air rules to clarify the issue of double counting benefits.

Comment 9: Commenter 17876 states that the EPA's attribution of 90% of the health benefits under this rulemaking to justify the further regulation of PM is problematic based on recent studies. *See, e.g.,* Koop, Gary, Ross McKitrick and Lise Tole (201 0) "Air Pollution, Economic Activity and Respiratory Illness: Evidence from Canadian Cities 1974-1994" *Environmental Modeling and Software* 2010, doi: 10.1 016/j.envsoft.201 0.01.01 0; Gary Koop, Lise Tole, "Measuring the Health Effects of Air Pollution: to what extent can we really say that people are dying from bad air?" Journal of Environmental Economics and Management (2004), 30-54.

Comment 10: Commenter 18023 believes the EPA's flawed cost-benefit analyses makes it difficult to assess the proposed rule under UMRA and EO 12866, which require the EPA to assess both the costs and benefits of the proposed rule. The commenter believes the EPA is double counting benefits associated with $PM_{2.5}$ in its RIA, and therefore has failed to meet its obligations to promulgate a regulation that imposes the least burden on society.

Response to Comments 6 - 10: On inclusion of $PM_{2.5}$ health co-benefits, the EPA disagrees with commenters that $PM_{2.5}$ health co-benefits should be excluded in the estimation of benefits expected by MATS. Accounting for ancillary benefits is standard practice in benefit-cost assessment since these benefits are a consequence of the rule, regardless of the rule's intended purpose (as noted also by commenter 17768). As such, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible, for the purpose of determining the likely impacts, not to justify an action. This rule is expected to achieve substantial $PM_{2.5}$ health benefits resulting from primary PM and SO_2 emission reductions, and these co-benefits are thus an important category to quantify.

Consideration of ancillary benefits in benefit-cost analysis is directed by OMB Circular A-4 (p. 26, available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/):

"Your analysis should look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks. An ancillary benefit is a favorable impact of the rule that is typically unrelated or secondary to the statutory purpose of the rulemaking (e.g., reduced refinery emissions due to more stringent fuel economy standards for light trucks) while a countervailing risk is an adverse economic, health, safety, or environmental consequence that occurs due to a rule and is not already accounted for in the direct cost of the rule (e.g., adverse safety impacts from more stringent fuel-economy standards for light trucks)."

It is also directed by the EPA's Guidelines for Preparation of Economic Analyses (p. 11-2, available at: http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html):

"An economic analysis of regulatory or policy options should present all identifiable costs and benefits that are incremental to the regulation or policy under consideration. These should include directly intended effects and associated costs, as well as ancillary (or co-) benefits and costs."

In line with this guidance, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible. We further note that we were unable to monetize other important benefits, including health benefits of ozone reductions, additional $PM_{2.5}$ health benefits, and direct health benefits of reducing SO_2. If we were able to fully monetize these benefits, the benefits would exceed the costs by an even greater amount than we currently estimate.

Regarding commenters' assertion that the EPA is double-counting $PM_{2.5}$ health benefits achieved by MATS with those achieved by other regulations and NAAQS, the EPA disagrees with these commenters that the quantified $PM_{2.5}$ health benefits are double-counted with the health benefits achieved by other regulations. The EPA's standard practice for its rules is to estimate, to the extent data and time allow, all benefits of the emissions reductions achieved by a rule *beyond control requirements for other rules*. If this rule was duplicative with other rules, then there would be no additional costs or benefits attributable to this rule.

When the EPA estimates the benefits for rules like MATS, we include other rules such as the CSAPR in the "baseline." Any emission changes expected as a result of MATS are additional emission reductions beyond those regulations (e.g., CSAPR) that were considered to be part of the baseline. Therefore, the benefits from particle reductions are not double-counting – they are real health benefits from emissions reductions achieved by MATS alone.

Further, the $PM_{2.5}$ health benefits expected from this rule are not double-counted with benefits estimated in the NAAQS RIAs. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that states may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However, some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in the illustrative $PM_{2.5}$ NAAQS RIA.

Regarding quantification of health benefits below the $PM_{2.5}$ NAAQS, the EPA notes that in implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ below the PM NAAQS in some areas. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations based on the scientific literature available at the time the standard is set. Although benefits occurring below the standard may be less certain than those occurring above the standard, the EPA considers them to be legitimate components of the total benefits estimate.

In response to the comment on climate benefits, we use best available scientific information and methods in monetizing the climate benefits of this rule and include a careful discussion of the associated uncertainties and limitations.

5. Health impacts are minimal and are not thoroughly investigated.

Comment 11: Some commenters (17621, 17689, 17775, 18033, 18963, 18023) argue that utility acid gas emissions (primarily HCl) cause insignificant harm. Commenter 18023 states that the conclusion that HCl could exacerbate ecosystem acidification is speculative and unsubstantiated. Commenters 18033 and 18963 point out that the EPA never provided a finding of public health concern to regulate non-Hg HAP, and provides no evidence that "more stringent control of acid gases would benefit ecosystems other than some vague referencing of the possibility." Commenters 17775 and 18033 argue that the predominant HAP in the acid gas group, HCl, poses no significant potential for exceeding the chronic RfC value according to the EPA's own calculations, even though the $PM_{2.5}$ benefits in the RIA are solely attributable to the control of HAP acid gases. Commenters 17621 and 18033 argue further that because HCl is a very minor contributor to all acidification of water bodies, the EPA's need for regulating acid gases from EGU's is insignificant. Commenter 17621 points out that because of this, HCl emissions have "not been the focus of past U.S. assessments of acidification."

Response to Comment 11: Based on recent peer-reviewed research including Evans et al. (2011), acid gases can significantly contribute to acidification. The paper presents experimental results that show 1) that HCl is highly mobile in the environment, transferring acidity easily through soils and water, 2) that HCl can transport longer distances than previously thought (given its presence in remote ecosystems, and 3) that it can be a larger driver of acidification previously thought. In 2009 the EPA published a comprehensive risk assessment of acidification effects of nitrogen and sulfur deposition and in 2011 published a Policy Assessment based on the findings in the Risk Assessment (both documents are available at: http://www.epa.gov/ttn/naaqs/standards/no2so2sec/index.html). Given the extent and importance of the sensitive ecosystems evaluated in the review of nitrogen and sulfur deposition any substance that contributes to further acidification must be considered to be affecting the public welfare.

Comment 12: Several commenters (16469, 17621, 17715) take issue with the use of the two primary health studies used in the benefits analysis (Pope et al., 2002; Laden et al., 2006). Commenter 17715 argues that the studies take a simplistic approach to their calculations (grouping all PM components together) even though there is evidence that PM components do not all have equal health significance. Commenter 17621 argues that because the dose-response function for $PM_{2.5}$ relied on two studies and not a full review of the published literature, it is flawed and only reflects a subset of the literature. Commenter 17621 also takes issue with the EPA's choice of dose-response function from the Laden study; the commenter argues that the EPA should have used only the most recent mortality risks instead of the risk for a combined time period, because the more recent time period is more relevant to the present. Commenter 17621 points out that had the EPA used the most recent mortality risk, the benefit estimates would be much lower. Commenter 17621 disagrees with the EPA's statement that some studies were excluded from analysis due to having study populations of a "selective nature," because the commenter argues that this is true of all studies, including the Pope and Laden studies. Commenter 17621 argues that the inclusion of other studies would be appropriate and could change the estimated benefits. Commenter 17621 argues further that the methodology used in these studies appears flawed, particularly in the methods used to estimate mortality benefits. They state that this could overestimate the benefits associated with changes in PM concentrations, and thus these studies should not be used until the flaws are remedied.

Response to Comment 12: The EPA disagrees that the methodology used to estimate $PM_{2.5}$ health impacts is flawed. The EPA methods for quantifying health benefits of emission reductions are based on the best available peer-reviewed science and methods that have withstood scrutiny from the EPA's independent SAB, the National Academy of Sciences, and continuous interagency review. We note that the evidence on differential toxicity of $PM_{2.5}$ components and mixtures is currently inconclusive. We therefore follow the advice of the EPA's Clean Air Science Advisory Committee (Hammitt et al. 2010, available at:
http://yosemite.epa.gov/sab/sabproduct.nsf/fedrgstr_activites/2nd%20Prospective%20812%20Study!OpenDocument&TableRow=2.3#2.), which concluded that "Although the possibility of differential toxicity among $PM_{2.5}$ components could be an important issue, the Council concludes that the state of the

knowledge does not permit a useful sensitivity analysis at this time" (p. 6). In response to commenter 17621, we note that we use concentration-response factors from the broadest time periods available to take advantage of the available data most comprehensively. The choice of relative risk estimates from Pope et al. (2002) and Laden et al. (2006) is supported by the EPA Advisory Council on Clean Air Compliance Analysis (Hammitt et al. 2010, available at: http://yosemite.epa.gov/sab/sabproduct.nsf/9288428b8eeea4c885257242006935a3/59e06b6c5ca66597852575e7006c5d09!OpenDocument&TableRow=2.3#2.):

> "Overall, the HES finds the EPA analyses, data choices, and methodologies to be sound. The EPA bases its estimates of the mortality benefits of reducing fine particulate matter (PM2.5) on data analyzed from two large, long-running landmark studies on the health effects of air pollution, the Harvard Six Cities Study and the American Cancer Society (ACS) Cancer Prevention Study (CPS). The HES finds the selection of these cohort studies as the underlying basis for PM mortality benefit estimates to be a good choice" (p. 1).

We further note that we also estimate mortality using functions derived by 12 experts in an EPA-sponsored expert elicitation (Roman et al. 2008). The Pope et al. (2002) and Laden et al. (2006) studies were found to be near the 25th and 75th %iles of the mortality effect estimates garnered from the expert elicitation. Our use of the expert elicitation functions provides one estimate of the range of possible impacts.

Comment 13: Commenters 17707 and 17824 suggest that there is little evidence to support a link between air quality and asthma. Commenters cite the increased asthma rate from 3.1% of the population to 8.2% of the population between 1980-2009, despite the decrease in SO_2 and NO_X rates by 70%. Commenter 17824 asserts that such evidence raises doubt as to the link between air quality and asthma.

Response to Comment 13: The commenters provide no references to support this argument. The EPA methods for quantifying health benefits of emission reductions are based on the best available peer-reviewed science and methods that have withstood scrutiny from the EPA's independent SAB, the National Academy of Sciences, and continuous interagency review. Note that the EPA estimates the reduction in asthma attacks, not the onset of asthma, for the calculation of health benefits.

Comment 14: Some commenters (17709, 17727, 17731, 17755, 17805, 18018, 18477) question the EPA's assessment of health benefits resulting from the reduction in emissions of HAP and substances other than HAP, such as fine PM. Commenter 18477 points out that in the Utility RTC, the EPA estimated that nickel emissions from oil-fired utilities would result in additional 0.2 cancer cases per year. Commenter 18477 also states that "EPA acknowledged in the Utility RTC that there was significant uncertainty regarding the risks from oil-fired utilities" and that even their conservative calculations of risk show very low risk of cancers. Commenter 18477 also argues that the EPA has not investigated the effects of nickel and HAP thoroughly enough to determine health risks, and the commenter suggests that the EPA should re-evaluate the health risks. This commenter suggests that the EPA must specifically reconsider the nickel speciation data used to calculate the nickel health risks in the Utility RTC, and incorporate more data provided by the industry to improve the calculations. The commenter also conducted their own risk analysis for nickel emissions using an assumption of 5% of nickel emissions as carcinogenic, and calculated risk below the threshold for delisting a source from regulation under section 112. Several commenters (17731, 17755, 18018) suggest there is a lack of substantive HAP health risks linked to current EGU emissions outside of Hg-related benefits, and commenter 17805 adds that the mechanism of human exposure and risk are poorly understood.

Commenter 17731 states that because of the lack of HAP risks, the EPA was unable to quantify all of the health and environmental benefits of the proposed rule. Commenters 17727 and 17709 point out air quality modeling by the Midwest Ozone Group showing reductions to comply with the Clean Air Interstate Rule will allow nearly all areas of the U.S. to meet fine particulate standards, meaning that the assessment of the proposed rule includes benefits that will already be achieved by other rules. The commenter requests that the EPA reassess the benefits, so that those living on a fixed income will not be unnecessarily burdened.

Response to Comment 14: The EPA's assessment of inhalation risks due to non-Hg HAP, by itself, is sufficient to support the determination that it is appropriate and necessary to regulate EGUs under section 112 of the CAA (see preamble for further details). The EPA disagrees with the commenters' assertions that nickel emissions can be assumed to be only 5% as carcinogenic as nickel subsulfide (see preamble for further details). The EPA disagrees with the commenters' assertion that the EPA's inability to quantify all of the health and environmental benefits of the proposed rule is due to a lack of associated HAP risks in the first place; rather, this is due to the lack of scientifically-accepted methodologies for estimating HAP-related benefits.

6. Health impacts are significant.

Comment 15: Numerous commenters (16404, 17254, 17408, 17409, 17766, 17811, 17852, 17871, 18432, 18435, 18436, 18487, 18501, 19536/19537/19538, 18932) explain that the elderly, young, poor and minority groups as well as those in the southeast face increased risk of health effects from breathing HAP. Some commenters (18435, 18436, 19536, 19537, 19538) discuss the vulnerability of children to the adverse health effects of air pollution, even in the prenatal stages. The commenters further state that people with chronic diseases are also exceptionally susceptible. Commenter 17811 states that HAP cause damage to eyes, skin, breathing passages, kidneys, nervous system, particularly to sensitive groups. In particular, commenter 17811 discusses the serious harm poor air quality causes to children, such as their lung development and adverse birth outcomes. Commenter 17811 cites studies that say harmful exposures among minority populations may be more than twice as great as exposures to the average U.S. population. Commenter 17766 describes a coal-fired power plant in Milwaukee, Wisconsin that emits 5,000 tons of CO_2, 1,500 tons of NO_X, and almost 350,000 tons of particulates into the air annually; a third of asthmatics in Wisconsin live within a few miles of the plant, and most of those who do are minorities. Several commenters (17766, 19536, 19537, 19538) also point out that power plants tend to be near low income people who lack insurance and do not have paid sick leave, and thus air pollution will cause greater inconveniences for them. Commenter 17409 refers to studies that associate violence, mental retardation, and schizophrenia with higher levels of metals in the blood. Commenter 17254 cites several studies showing the susceptibility of sensitive populations to poor air quality, including one study that revealed a "clear association between respiratory emergency department visits in Atlanta and sulfate rich fine PM, the kind of fine particles formed in the atmosphere as a result of gases emitted by coal fired power plants." Commenter 17254 also cites a study showing that "children with autism were more vulnerable to environmental pollutants because they have lower levels...of the body's natural defense for excreting environmental pollutants." Commenter 18932 states that the southeast has one of the highest concentrations of coal-fired power plants in the nation, putting an undue health burden on the population.

Response to Comment 15: The EPA agrees that exposure to fine particulates and toxic air pollutants is associated with many adverse health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Comment 16: Many commenters (16404, 16826, 17157, 17283, 17409, 17620, 17676, 17811, 17843, 17875, 17916, 18022, 18027, 18029, 18039, 18421, 18425, 18432, 18435, 18436, 18477, 18478, 18487, 18501, 18759, 19145, 18932) describe the Hg and non-Hg HAP that contribute to premature death, environmental contamination and exposure, and a host of diseases. Commenter 19145 cites the statistic that at least 1 in 12 women of childbearing age have enough Hg in their bodies to put a baby at risk for Hg poisoning. Commenter 18759 reports that 25 million Americans have asthma, of which 7.1 million are children. Commenters 18435 and 18425 state that SO_2 and NO_X are dangerous pollutants that will be significantly reduced by this rule. Commenter 18435 argues further that many of the constituents of $PM_{2.5}$ are known to cause cardiovascular effects and respiratory harm. Commenter 18435 also presents the results of their calculation using the CALPUFF atmospheric dispersion model to estimate health benefits from the proposed rule; their calculations showed that use of the best available control technology would avert 70 deaths per year in a population of 33 million people. Commenter 18421 points out the toxic effects of lead, particularly to children, and the potential carcinogenicity of organic HAP like dioxins and furans. Commenter 18039 describes the accumulation of Hg in the environment, and the resulting exposure this causes to the population.

Commenter 17916 states that the rule will also reduce emissions of harmful criteria pollutants. Commenter 17843 describes the link between nickel emissions with increased risk in daily mortality. Commenter 17620 states that the "most recent EPA assessment of cancer risks from ambient HAP concentrations estimates that the entire US population at the time of the assessment had an increased cancer risk of greater than 10 in 1 million, while 13.8 million people have an increased cancer risk of greater than 100 in a million, as a result of breathing HAP at 2005 ambient levels over the course of their lifetime." Commenter 18932 cites a study that concluded that metals and other toxic substances known to be emitted by coal-fired power plants created elevated risk levels for cancer and non-cancerous health effects and are known to seriously injure human health. Many of the toxic metals from coal combustion are emitted as fine particulates, which bypass the body's defenses and lodge in the lungs leading to short and long-term health problems. Multiple commenters (17157, 17409, 17620, 17826, 18029, 18487, 18759) state that the 400 coal-fired power plants across the country release over 386,000 tons of HAP annually, and cleaning up these power plants can save over 17,000 lives annually. Commenter 17409 cites a study in Pennsylvania that estimates 1359 premature deaths are attributed to toxic emissions from power plants in 2010. This commenter (17409) also cites a Clean Air Task Force study that estimates the health impacts of the plant BL England at 32 heart attacks, 300 asthma attacks, and 19 deaths. Commenter 18487 states that due to the high toxicity of dioxins, these should be regulated in the final rule. Commenters 16404 and 18932 cite estimates of over 13,000 deaths, nearly 10,000 hospitalizations and more than 20,000 heart attacks per year nationwide at an economic cost of $100 billion. Some commenters (17283, 18932) do not fully agree with the decision to use $PM_{2.5}$ as a surrogate for all non-Hg metal HAP, but they support the EPA's finding that toxic components of fine particulate pollution from coal-fired power plants must be regulated under stringent MACT standards. Commenter 18932 discusses a study in Alabama that concluded that the levels of air toxics in the air had "elevated risk levels for cancer and non-cancerous health effects" and are "emitted in harmful quantities by coal-fired power plants in the region." Commenter 18932 also details the amount of each of the following pollutants as well and the health issues associated with them: arsenic, antimony, beryllium, cadmium, chromium hexavalent compounds, cobalt, manganese, nickel, selenium sulfide, hydrogen cyanide, hydrogen chloride, hydrogen fluoride.

Several commenters (18421, 17921, 17811, 18436) argue that HAP cause acidification and degradation to the environment. Commenters point out that toxic metals contaminate and bioaccumulate in waterways and animal life, causing further exposures to local communities and harming recreational activities. Commenter 17921 points out that it is difficult to determine health effects of acid emissions, though occupational exposures to HCl and HF have been shown to have health effects, and prospective studies show deleterious lung effects in children. Commenter 18421 states that coal-fired plants are responsible for approximately 76% of all acid gas emissions, which they argue can cause problems in the upper respiratory tract, especially harmful to children. Commenter 18421 also states that acid gas emissions contribute to acidification of ecosystems, and this causes harm to human health and the environment.

Several commenters (19536, 19537, 19538) explain that meeting the limits for toxic air emissions set by the proposed rule provides reductions in secondary $PM_{2.5}$, especially in SO_2 and NO_X. In addition, the commenter points out that fuel switching and retirements are also expected to reduce NO_X emission and nitrate particles.

Response to Comment 16: The EPA agrees that the proposed rule will lead to reductions of criteria and HAP responsible for significant adverse health effects and that such reductions will produce substantial public health benefits.

The EPA agrees that Hg exposure in wildlife is responsible for various adverse health effects in many species across the U.S. and recognizes that research is ongoing in this area. As discussed in the Appropriate and Necessary finding, the EPA agrees that there are environmental risks from exposures of ecosystems through Hg and non-Hg HAP deposition. The benefits to ecological health remain unquantified in the assessments for this rule due to data and methodological limitations. The EPA cited relevant articles from the special edition of Ecotoxicology mentioned by the commenter in the ecosystem effects section on Chapter 5 of the RIA for this rule. Ecotoxicology. 17:83-91, 2008.

The EPA agrees that acidification poses a significant risk of adverse effects to fish and wildlife in aquatic and terrestrial ecosystems. Please refer to EPA's recent Risk and Exposure Assessment for Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur-Main Content - Final Report available at http://www.epa.gov/ttn/naaqs/standards/no2so2sec/data/NOxSOxREASep2009MainContent.pdf for a comprehensive report on those effects including increased Hg methylation in acidified systems. Based on recent peer-reviewed research including Evans et al. (2011), acid gases can significantly contribute to acidification and the EPA agrees that those acid gases pose a risk for acidification of ecosystems. However due to data and methodological limitations the EPA was not able to quantify those risks and benefits.

Regarding health effects of acid emissions, the EPA agrees that the large percentage of acid gas emissions that can be attributed to EGUs may cause or contribute to chronic respiratory health problems. They are being subjected to emission limits in today's final rule.

7. The proposed rule will harm public health.

Comment 17: Commenter 17919 suggests that the proposed rule will adversely impact public health by increasing the cost of medical care, by "suppressing economic growth and the improved health it brings," and by inefficiently using resources on expensive rulemakings instead of other public health measures. The commenter points out that the health sector is the second most energy intensive commercial sector, and increases in energy costs would translate to rapid increases in health care costs.

Response to Comment 17: The commenter's assertion relies on the theory that the cost of the rule will result in lost income or employment that will, in turn, result in negative health effects that offset the positive health effects of the rule. (This is referred to as a "health-health tradeoff.") The EPA disagrees with this point and notes that there are a number of conceptual and empirical problems with any attempt to quantify the health-health tradeoffs of regulatory action to control air pollution. These analyses rely on questionable applications of cross-sectional data and ignore key factors that may influence changes in population health risks. Additionally, marginal decreases in household income caused by the pass through costs of the regulation are unlikely to cause large changes in any single aspect of household spending, such as health care. These analyses also fail to consider that household income may increase if individuals are able to work (or work more) as a result of improved health, offsetting some or all of the pass through costs of the rule. For these reasons, the EPA's science and economic peer review panels have consistently advised against attempting to quantify any health-health tradeoffs of regulation.

8. Support for the proposed rule.

Comment 18: Multiple commenters (12267, 17381, 17852, 17871, 17880, 17882, 17903, 17916, 18022, 18432, 18435, 18438, 18478, 18501, 18961) support the proposed rule and agree with the regulations designed to address the source of pollution as strictly as necessary to protect human health. Commenters 17882 and 18501 further add that coal-fired power plants are responsible for 99% of Hg emissions from the power sector in the U.S., justifying the rule. Commenter 17903 points out that some air toxics exist at high levels near coal-fired facilities, such as aldehydes and PAHs, that are not regulated by any ambient monitoring requirements. Commenter 17916 points out that much of the Hg deposited in Ontario originates in U.S. coal-fired EGUs, that has many potential adverse health effects, thus they strongly support the rule. Commenters 18432 and 18435 further urge the EPA not to weaken the proposed rule.

Response to Comment 18: The EPA acknowledges generally supportive comments (including commenters 12267, 15002, 17381, 17648, 17852, 17871, 17880, 17882, 17903, 17916, 17921, 18022, 18432, 18435, 18438, 18478, 18501, 18541, 18961, 19536, 19537, 19538, 18932) on the quantification of $PM_{2.5}$ health co-benefits. The EPA agrees with these commenters that the large health co-benefits of this rule resulting from $PM_{2.5}$ reductions far outweigh the costs and may underestimate the true benefits, as some health impacts (e.g., ozone health benefits, enhanced ecosystem services, increased fish consumption by women) were not able to be quantified.

9. Miscellaneous comments.

Comment 19: Commenter 16630 asks how averaging in combination with the credits affect the environment.

Response to Comment 19: In the proposed rule, the EPA planned to allow averaging of existing sources in the same subcategory at a common plant site for a given HAP. New and existing sources could not average and oil and coal could not average. This will not change for the final rule. The EPA has designed a rule that is intended to offer flexibility (including the averaging provisions), to the extent possible, while ensuring public health is protected in accordance with requirements outlined in the CAA.

Comment 20: Commenter 17734 submits information on technology developed by the commenter's company that could be used to remove HAP from EGUs. The technology is a "non-carbon Hg sorbent that effectively captures Hg from coal-fired plants" from Novinda.

Response to Comment 20: The EPA thanks the commenter for this information but believes this comment is out of the scope of this rule.

Comment 21: Commenter 17736 disagrees with the EPA's claim that "it is reasonable to only consider emissions reductions achieved from requirements directly imposed on EGUs because EPA cannot predict with any certainty how EGUs would satisfy other required reductions." The commenter argues that the EPA can use the EGU's Title V permit to identify all CAA requirements and make regulations accordingly.

Response to Comment 21: Commenter appears to take issue with the EPA's approach to evaluating whether it is "necessary" to regulate EGUs. See the preamble to the proposed and final rule for the EPA's interpretation of the term necessary and determinations that it remains necessary to regulate HAP emissions from EGUs. As indicated therein, we maintain that the 2000 finding was reasonable at the time it was made based on the available information and that our new analyses of wherein we considered whether HAP emissions remaining after imposition are reasonably anticipated to pose a hazard to public health and the environment far exceeds what is contemplated in CAA section 112(n)(1)(A).

Comment 22: Commenter 17811 argues that the proposed rule is insufficient to reduce levels of HAP to safe concentrations, based on modeling and monitoring data in Alabama.

Response to Comment 22: The EPA disagrees that today's final rule, which is technology-based, must reduce levels of HAP from EGUs to safe concentrations. It is the requirement of the residual risk rulemaking, which must occur within 8 years of promulgation of the technology-based standards, in which EPA evaluates whether additional HAP emissions control is necessary to protect public health with an ample margin of safety. We have based the final rule on the performance of the best performing sources in accordance with the statute.

Comment 23: Commenter 18502 argues that Puerto Rico currently is in compliance with all ambient air quality standards and thus further reductions in HAP emissions from the proposed rule will have no benefits to air quality on the island.

Response to Comment 23: Compliance with the NAAQS is not relevant to whether there would be benefits associated with this rule. The benefits are related to the emission reductions associated with applying controls. Both PM and ozone as well as many HAP have no threshold below which there are no health effects. Therefore, reducing emissions will lead to health benefits, even though we don't have the data to quantify these benefits at this time.

Comment 24: Commenter 17848 states that the numbers regarding monetized benefits in the proposed rule do not match the RIA. The rule states that total Hg-related benefits were calculated to be $450,000 to $890,000 at a 7% discount rate while the RIA states that Hg-related benefits were calculated to be $5,000 to $9,000 at a 7% discount rate. The commenter requests that the EPA review the information and revise accordingly, and also suggests that the EPA use a single base year (2006$ or 2007$) when tabulating benefits.

Response to Comment 24: Any discrepancies in the proposal will be corrected in the final RIA. All costs and benefits are presented in 2007$ in the final RIA.

6L - Impacts/Costs: Mercury Benefits

Commenters: 12798, 15002, 15160, 16122, 16682, 17254, 17405, 17408, 17409, 17620, 17621, 17676, 17679, 17681, 17682, 17683, 17716, 17731, 17732, 17751, 17754, 17761, 17766, 17789, 17811, 17843, 17844, 17854, 17875, 17882, 17904, 17922, 17926, 18014, 18020, 18033, 18043, 18248, 18421, 18425, 18432, 18435, 18436, 18443, 18484, 18487, 18498, 18500, 18541, 19210, 19214, 19506, 6640, 18932, 18023

1. General impacts.

Comment 1: Commenter 17807 states that the EPA should incorporate the latest Hg toxicological data, reevaluate its conclusions, and determine whether the proposed rule is appropriate and necessary.

Response to Comment 1: The EPA disagrees that the data and methods used to determine the risks and benefits for the proposed rule are inadequate. The SAB in its review of the EPA's Risk Assessment and supporting TSD finds that "the risk assessment provides an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs." The SAB approved of the overall design and general approach and considered the spatial resolution of the modeling of Hg deposition to watersheds to be appropriate for the analysis. There was agreement that the approach used to identify watersheds to include in the assessment was reasonable. This approach was based upon the availability of fish tissue methylmercury data and census data on target populations with potential subsistence fishers. The SAB agreed that the EPA's calculation of a hazard quotient for each watershed included in the assessment is appropriate as a principal means of expressing risk.

The EPA Science Advisory Board Report available at:
http://yosemite.epa.gov/sab/sabproduct.nsf/ea5d9a9b55cc319285256cbd005a472e/aaf67ae4dd199409852578cb006bcb04!OpenDocument

Comment 2: Commenter 18023 states the if the EPA had reported IQ loss estimates to only whole numbers or one significant figure, the differences between the scenarios in Table 5-6 would be zero indicating no benefit at all. According to the commenter, the EPA compounds this mistake by estimating a cost associated with accumulated IQ loss after recognizing that these benefits would be lower if lags were properly considered.

Response to Comment 2: The EPA disagrees with the commenter's statement that the benefits calculated would be zero. The benefits calculated are averaged across the population and hence the small increments yield the benefits reported. In addition, the EPA recognizes that the IQ benefits presented are an underestimate of the benefits of reducing Hg emissions. According to the SAB's review of the Mercury Risk TSD for this rule, "The loss of IQ points is likely to underestimate the impact of reducing methyl mercury in water bodies. The reason is that IQ score has not been the most sensitive indicator of methylmercury's neurotoxicity in the populations studied. As noted in the Mercury Risk TSD, in the Faroe Island study the most sensitive indicators were in the domains of language (Boston Naming), attention (continuous performance) and memory (California Verbal Learning Test), neuropsychological tests that are not subtests of IQ tests and are not highly correlated with global IQ. In the Seychelles study, the Psychomotor Development Index has been most sensitive measure and, while this is a component of the Bailey Scales of Infant Development, it is not highly correlated with cognitive measures."

The EPA acknowledges that MMAPS does not account for a time lag in ecosystem response to reductions in Hg emissions. Ecosystems are highly variable in their response to reductions in Hg emissions. Due to limitations in data and methodology, EPA was not able to quantify the effect of lag times on benefits.

Comment 3: Commenter 17621 states that with respect to the "hypothetical full scale IQ" this relatively small incremental change in IQ (0.18 on a 100-point IQ scale) associated with a 1 ppm Hg increase in hair cannot itself be measured for an individual, but must be estimated for the total population (through a series of analytical and exposure assumptions) to derive estimates at the national level (e.g., 510.8 IQ points saved in RIA, Table 5-7). The individual effects estimates for the "average" IQ loss per exposed child were defined out to the fourth or fifth decimal place (see RIA, Tables 5-6 and 5-7) to indicate the potential (and relatively) small effects across the different exposure scenarios.

Response to Comment 3: Although the EPA disagrees that the IQ results are too small to be important, the EPA acknowledges that IQ is not the most sensitive neurodevelopmental endpoint affected by methylmercury exposure. The EPA analysis of potential IQ loss from methylmercury exposure is for population effects, as is done for any quantitative estimate of risk. For precision, it is appropriate to use a large number of significant figures in calculation, if this is supported by the data inputs. Upon completion of calculations, the estimate is rounded to the number of significant figures reflective of the least precise term. In the case of IQ, based on the effect estimates from the underlying epidemiological studies and the exposure estimates, the level of precision is to 2 significant digits to the right of the decimal place.

The EPA independent SAB recommended that the IQ analyses be retained but de-emphasized in the documentation underlying the final regulation (U.S. EPA-SAB, 2011). SAB concluded, "The Panel does not consider it appropriate for EPA to use IQ loss in the risk assessment and recommended that this aspect of the analysis be de-emphasized, moving it to an appendix where IQ loss is discussed along with other possible endpoints not included in the primary assessment. Although the Panel agreed that the concentration-response function for IQ loss used in the risk assessment is appropriate, and no better alternatives are available, IQ loss is not a sensitive response to methylmercury and its use likely underestimates the impact of reducing methylmercury in water bodies." (U.S. EPA-SAB, 2011) The EPA is following the SAB recommendation by deemphasizing the IQ analysis and placing that analysis in an appendix to the revised TSD.

Comment 4: Many commenters (15002, 15160, 17408, 18425, 18421, 18432, 19210, 12798) support this rulemaking because it will reduce human health risks associated with exposure to Hg emissions from EGUs. Several commenters (19210, 15160, 18421) note that HAP, such as Hg, are linked to many health problems, including cancer, heart disease, neurological damage, birth defects, asthma, and premature deaths. Commenter12798 states that the health of Americans and the economy will be greatly aided by these new regulations. The commenter quotes a Harvard study that found Hg emissions from coal-fired power plants may cost the country nearly $30 billion per year in health, environmental and economic impacts and suggested a cost of another $100 billion per year from particulate emissions and $200 billion from climate change emissions. The commenter considers these costs outweigh the potentially higher utility bills that could result from the proposed rule, and states that the utility sector has had adequate time to prepare. Commenter 18421 notes that data from several studies have shown links between methylmercury exposure, adult leukemia, and increased mortality rates (Salonen, J.T., K. Seppänen, T.A. Lakka, R. Salonen and G.A. Kaplan, *Mercury accumulation and accelerated progression of carotid atherosclerosis: A population based prospective 4-year follow-up study in men in Eastern Finland*, Atherosclerosis. 148, 265-273 (2000) and Yorifuji T, Tsuda T, Kawakami N, *Age* *standardized cancer mortality ratios in areas heavily exposed to methyl mercury*, 88Int. Arch. Occup. Environ. Health. 679, 679-88 (2007).

Response to Comment 4: The EPA agrees that exposure to fine particulates and toxic air pollutants is associated with many adverse health effects and reducing exposure to these pollutants is associated with substantial public health benefits. The EPA also agrees that the benefits of the proposed rule outweigh the potential costs and that the proposed implementation schedule is reasonable.

Comment 5: Commenter 15002 expresses concern that even low levels of Hg exposure may be harmful because none of the studies of Hg toxicity have shown a threshold effect.

Response to Comment 5: The EPA agrees that there may be no threshold below which PM, Hg and other HAP have no effect and, in fact, the EPA uses a linear relationship in the concentration-response functions for those pollutants.

Comment 6: Commenter 19506 questions whether the benefits associated with the rule will actually be achieved. This commenter notes that the Hg emissions within Indiana have decreased by approximately 20% over the past 14 years, but concentrations of Hg from wet deposition sampling have only decreased by 7% with no apparent change in Hg concentrations within fish tissue in Indiana over the past 22 years.

Response to Comment 6: The EPA disputes the commenter's belief that this rule will not reduce Hg levels in fish. The data used in support of this RIA do not reflect the commenter's assertion. The EPA notes that in some cases, Hg levels in fish can decrease quickly following reductions in Hg deposition. However, the time lag between reduced Hg deposition and reduced Hg levels in fish can vary greatly and is not accounted for in the RIA benefits analysis.

Comment 7: Commenter 18500 states that the EPA describes the Hg problems without providing evidence that actual harm in the U.S. can be attributed to EGU Hg emissions, or even to all Hg deposition. According to the commenter, the EPA fails to demonstrate that meaningful benefits will be obtained from reducing Hg deposition in the U.S. On page 4.9 of the March 2011 RIA for the Toxics rule, the EPA states, "Model results for the continental United States indicate that total mercury deposition (wet and dry forms) reductions from this sector [EGUs] would be 24,000 $\mu g/m^2$(1.0% of total mercury deposition from all sources.

Response to Comment 7: The EPA disagrees with the commenter's assertion that meaningful benefits would not accrue to the public due to reductions in Hg from U.S. EGUs. Chapter 5 of the RIA presents a detailed analysis of the benefit to IQ in children. The SAB has supported the model used in the RIA analysis and states, "The support for the model of the relationship between IQ and methylmercury exposure comes from Axelrad and Bellinger (2007) and from a whitepaper produced by Bellinger (2005)." (U.S. EPA-SAB, 2011) The analysis in the RIA is not intended as the basis of the rule. It is intended only to estimate the costs and benefits of the proposed rule and therefore the IQ loss estimates presented in the RIA do not represent an attempt to afford more stringent than necessary protection in this rule. Furthermore, the EPA does not believe that the benefits of this rule are insignificant. The benefits of reduction of Hg exposure are underestimated on several counts 1) IQ is not the most sensitive indicator of neurological effects, 2) many health effects are unquantified, 3) benefits of reduction of other HAP are unquantified and 4) effects on ecosystems and wildlife are likewise unquantified. In addition, the co-benefits of reducing PM exposure are quite substantial and outweigh the costs of the rule.

In addition, the EPA recognizes that the IQ benefits presented are an underestimate of the benefits of reducing Hg emissions. According to the SAB's review of the TSD for this rule, "The loss of IQ points is likely to underestimate the impact of reducing methyl mercury in water bodies. The reason is that IQ score has not been the most sensitive indicator of methylmercury's neurotoxicity in the populations studied. As noted in the TSD, in the Faroe Island study the most sensitive indicators were in the domains of language (Boston Naming), attention (continuous performance) and memory (California Verbal Learning Test), neuropsychological tests that are not subtests of IQ tests and are not highly correlated with global IQ. In the Seychelles study, the Psychomotor Development Index has been most sensitive measure and, while this is a component of the Bailey Scales of Infant Development, it is not highly correlated with cognitive measures."

Comment 8: Commenter 18023 states that the EPA's analysis lacked transparency and therefore prevented meaningful review. One example, according the commenter, was the point the EPA made in a footnote on Page 5-78 of the RIA that monetized benefits of the rule could be significantly lower if lags in response to decreased Hg deposition were taken into account. The commenter states that lags are known to occur in many if not most aquatic ecosystems and that "a portion of the deposition is unlikely to reach the water at all."

Response to Comment 8: The EPA acknowledges that MMAPS does not account for a time lag in ecosystem response to reductions in Hg emissions. Ecosystems are highly variable in their response to reductions in Hg emissions. Due to limitations in data and methodology, the EPA was not able to quantify the effect of lag times on benefits.

2. Impacts on pregnant women and children.

Comment 9: Many commenters (15002, 15160, 16682, 6640, 17676, 17408, 17766, 17844, 17854, 17875, 17922, 18421, 18432, 18435, 18436, 18932) express concern about the Hg levels found in children and women of childbearing age. Several commenters (15002, 18932, 17875) express concern that a large number of women of childbearing age are exposed to Hg at levels that lead to cord blood Hg levels that exceed the EPA reference dose. Commenters 15160 and 17408 identify potential health impacts of Hg exposure in children and developing fetuses, including speech, motor control, reading and writing as well as asthma, neurological damage, cancer, birth defects and other chronic health disorders. Commenter 15160 quotes data from the NC Department of Health and Human Services that estimate at least 11,811 babies are born annually with blood Hg levels that put them at risk for lifelong learning disabilities, fine motor and attention deficits and lowered IQ. Commenters 15160 and 17875 note that as many as one in six women of childbearing age have enough Hg in their blood to present a serious risk to a fetus during pregnancy.

Comment 10: Commenter 16640 explains that Hg accumulates in the environment and causes exposures long after being released from a power plant and bioaccumulates in humans along with arsenic, chromium and lead. The commenter quotes the American Academy of Pediatrics Policy Statement on Mercury which calls for, ."..efforts should be made to reduce exposure to the extent possible to pregnant women and children as well as the general population." The commenter urges the EPA to set the strongest possible standard for Hg and other air toxics.

Response to Comments 9 - 10: The EPA agrees that Hg levels in women of childbearing age are of concern and that in utero exposure to levels above the reference dose may lead to adverse health impacts in children. The EPA further agrees that Hg and certain other HAP bioaccumulate and persist in the environment.

Comment 11: Several commenters quote data from recently published studies on the impacts of Hg exposure. These include:

- Commenter 17676 quotes data published in 2000 by the National Academy of Science and the National Research Council showing that over 60,000 children are born each year at risk for adverse neurological effects due to in utero exposure to methylmercury (see National Academy of Science and Nation Research Council, *Toxicological Effects of Methylmercury*, 2000, available on the Web at: http://www.nap.edu/openbook.php?record_id=9899&page=327, 327).
- Commenter 18421 quotes a 2006 study by Dr. Kathryn Mahaffey estimating that approximately 410,000 infants are born in the U.S. each year to mothers with blood Hg concentrations in excess of the EPA's reference dose.
- Commenter 18421 quotes a recent study of women conducted in Durham, North Carolina that found 30% of the women participating in the study had at least 1 ug/L of Hg in their blood, approximately 2% had blood Hg levels above 3.5 ug/L (level considered to be of concern during pregnancy), and 12.5% of women of Asian/Pacific Islander decent had blood Hg levels above 3.5 ug/L (see Miranda et al., Mercury Levels in an Urban Pregnant Population in Durham County, 8 North Carolina. Int. J. Environ. Res. Public Health 698, 698-712 (2011).
- Commenter 17408 quotes research conducted at the Children's Environmental Health Sciences Center at the University of Wisconsin that demonstrates developmental exposures to Hg are sufficient to cause alternations to nerve function causing permanent damage that has been implicated in development of neurodegenerative diseases, such as Alzheimer's and Parkinsons. This commenter also notes that recent research has shown that the toxic effects of Hg exposure are passed down from one generation to another resulting in developmental and behavioral issues in the children and grandchildren of individuals exposed to low levels of Hg.
- Commenter 18421 quotes two studies conducted in Korea. The first study identified a link between adult leukemia and exposure to high levels of methylmercury (see Yorifuji T, Tsuda T, Kawakami N, *Age standardized cancer mortality ratios in areas heavily exposed to methyl mercury*, 88Int. Arch. Occup. Environ. Health. 679, 679-88 (2007). The second study evaluated 274 Korean children found an association between Hg concentrations in urine and increased cholesterol, which is a risk factor for various forms of cardiovascular impacts (see Bose-O'Reilly et al, *Mercury Exposure and Children's Health*, Curr Probl Pediatr Adolesc Health Care. 2010 September; 40(8): 186–215).
- Commenter 18432 quotes a recent study conducted in the City of Chester and Borough of Eddystone, Pennsylvania located in close proximity to coal- and oil-fired EGUs. This study shows that asthma rates among children in these communities exceed 36 %.

Other commenters (18421, 18541, 17408-14) identify instances of methylmercury poisoning, such as the outbreaks in Minamata, Japan where the mothers exposed to elevated levels of methylmercury through consumption of contaminated fish typically did not exhibit any symptoms themselves, but gave birth to children with severe neurological and birth defects. Commenter 18421 also cites an outbreak of Hg poisoning in Iraq where consumption of contaminated grains resulted in serious reproductive impacts, including lower levels of pregnancies among the affected population.

Response to Comment 11: The EPA agrees with the commenters that research is ongoing and that new findings are being published that shed new light on these ubiquitous and harmful pollutants. The EPA is aware of the poisoning events detailed in the comments above and included descriptions of these events in the RIA for this rule.

Comment 12: Commenter 17681 questions whether this rulemaking will reduce the health impacts of Hg exposure on women and children. This commenter argues that this rulemaking may not reduce the Hg exposure for women of childbearing age that eat canned fish because it may result in manufacturing companies relocating to countries where there are less stringent Hg emission limits on EGUs.

Response to Comment 12: The National Scale Mercury Risk Assessment shows that changes in Hg emissions from 2005 to 2016 are in fact likely to result in reductions in U.S. EGU attributable fish tissue Hg concentrations.

3. Impacts on IQ.

Comment 13: Many commenters (15002, 15160, 17409, 17716, 17766, 18421, 18425, 18435, 19506, and 18932) note that Hg exposure has been associated with cognitive delays, learning disabilities, and lower IQ levels. Commenter 15002 notes that the EPA's own analysis has shown that a child born to an African-American woman in 2016 who consumed fish at the 90th percentile would experience a loss of approximately 7.7 IQ points in the absence of the proposed rule. Commenters 15160 and 18932 state that the North Carolina Department of Health and Human Services estimates that at more than 11,000 children per year are born in North Carolina with blood Hg levels that place them at risk for lifelong learning disabilities, fine motor and attention deficits, and lowered IQ. Commenters 17409 and 18435 identify recent studies such as the 2005 study by Transande that estimated between 300,000 and 600,000 children each year have cord blood Hg levels that are associated with loss of IQ points and estimate that the lost productivity from the lower IQ levels is almost nine billion dollars.

Commenter 18425 states that severe impacts on cognitive thinking, memory, attention, language, and fine motor and visual spatial skills have been seen in children exposed to methylmercury in the womb. This commenter stated that the EPA's data show 10,543 children in Wisconsin were prenatally exposed to unsafe levels of Hg in 2005, resulting in a 0.10 point loss in IQ per child (a total IQ loss in Wisconsin of 1,026.2 points). This commenter also notes that the proposed Air Toxics Rule will result in nearly an 8.3% reduction in the average maternal daily Hg ingestion from the 2005 baseline, which would result in more than 10% reduction in the average IQ loss per child and total IQ loss across Wisconsin due to reduced Hg exposure from in-state sources.

Response to Comment 13: The EPA agrees that in utero and early childhood exposure to methylmercury can lead to neurological deficits in children and that the economic consequences of such deficits can be substantial.

Comment 14: Commenter 15002 believes that the EPA underestimated the impact of Hg on IQ by restricting the analysis to populations who consume self-caught fresh-water fish and omitting Hg exposures from other freshwater and saltwater fish. This commenter also stated there is no evidence to support the hypothesis that some low level of Hg exposure is entirely without effect and that if the effect of lead on IQ extrapolates to the Hg, then low level Hg exposures may have a greater effect per unit exposure than higher levels.

Response to Comment 14: The EPA agrees that there may be no threshold below which PM, Hg and other HAP have no effect and, in fact, the EPA uses a linear relationship in the concentration-response functions for those pollutants. We acknowledge the commenter's belief that the analysis of Hg impacts and health benefits may be conservative.

Comment 15: Multiple commenters (17621, 17716, 18498, 19506, 17681, 17731, 18033, 18443) believe this rulemaking will have little impact on IQ. These commenters argue that the EPA RIA shows only a fraction of an IQ point gain for the most exposed individuals, with the average effected individuals as prenatal children, 244,000 annually, experiencing only a 2/1000 IQ point gain. Commenter 18498 questions whether the EPA's IQ impacts are real, while commenters 17716 and 19506 argue that the benefits of the rule are insignificant. Commenter19506 believes that the benefits to IQ levels would still be insignificant even if the EPA included the impacts of commercially caught fresh and saltwater fish and self-caught saltwater fish in their analysis. Commenter 17681 argues that the aggregated benefit estimate of 0.00209 IQ points lost is below the level that can be measured by an IQ test.

Commenters 17716 and 17731 state that the EPA's 0.11/ 0.10 average IQ loss per exposed child and 0.176 point for the most at risk group is much lower than the EPA's recent determination that a potential health risk occurs at 1-2 point IQ loss (The NAAQS for Lead, 73 FR 66964 (Nov. 12, 2008)). The commenter states that the EPA declined to set a more stringent NAAQS for lead because the estimated average IQ loss was lower than the 1-2 point range and argues that the proposed Hg limits are likely more stringent than needed because the current Hg emission levels from EGUs have been shown to result in a 0.176 point IQ loss for the most at risk children, which is well below the EPA-determined 1-2 point IQ loss level.

Commenter 17621 notes that in monetizing the loss of IQ the EPA relied on the Bureau of Labor Statistics National Longitudinal Survey of Youth (a national data set used to estimate the relationship between IQ and lifetime earnings). The commenter states that this survey does not contain a direct measure of IQ and is instead based on an Armed Forces Qualification Test (AFQT) that has been scaled to estimate IQ. The commenter states that an early analysis conducted at the request of the military reported a 0.77–0.80 correlation between AFQT scores and scores on a full-scale IQ test, the Wechsler Intelligence Scale for Children (Office Secretary of Defense, 1980) and that the EPA should take into consideration the relative loss of precision in scaling between the AFQT and a full-scale IQ test in light of the small changes in IQ presented in the RIA IQ loss/reductions analysis.

Response to Comment 15: The EPA disagrees that the IQ impacts are not real and notes that the average reduction in IQ loss reported in the RIA do not reflect the greater than average impacts that reduced exposure would have at the tails of the distribution. The EPA uses a linear response model to predict IQ loss due to methylmercury exposure because there is no literature to date that shows a threshold below which no effect is observed. The SAB has supported the model used in the RIA analysis and states that "The support for the model of the relationship between IQ and methylmercury exposure comes from Axelrad and Bellinger (2007) and from a whitepaper produced by Bellinger (2005). It was noted that the 1-2 point decrease reflects the mean response, but that a decrease of 1-2 points at the mean results in a much larger decrease at the tails of the distribution. This can result in a greater impact on those with IQ's that are much lower or higher than the mean." (SAB Report available at: http://yosemite.epa.gov/sab/sabproduct.nsf/ea5d9a9b55cc319285256cbd005a472e/aaf67ae4dd199409852578cb006bcb04!OpenDocument) The analysis in the RIA is not intended as the basis of the rule. It is intended only to estimate the costs and benefits of the proposed rule and, therefore, the IQ loss estimates presented in the RIA do not represent an attempt to afford more stringent than necessary protection in this rule.

The EPA does not believe that the benefits of this rule are insignificant. The benefits of reduction of Hg exposure are underestimated on several counts 1) IQ is not the most sensitive indicator of neurological effects, 2) many health effects are unquantified, 4) benefits of reduction of other HAP are unquantified and 4) effects on ecosystems and wildlife are likewise unquantified. In addition the co-benefits of reducing PM exposure are quite substantial and outweigh all the benefits estimates for Hg.

The EPA agrees that the differences between the AFQT and full-scale IQ tests are a source of uncertainty; however, the EPA believes that the effect on the estimates would be very small since the difference between the two tests is small.

Comment 16: Several commenters (17681, 17769, 17807 and 18034) assert that the 1999 NHANES data is out of date. These commenters state that more recent data (such as Caldwell, et. al. (2009), *International Journal of Hygiene and Environmental Health*, vol. 212, pp. 88-598) show a decline in NHANES blood Hg levels since 1999 and indicate that blood Hg levels have been below the EPA rfd since 2001.

Response to Comment 16: The EPA did not apply any data from NHANES survey in the analysis of Hg effects on IQ in the benefits estimates for the RIA. The estimates were generated using data and models reviewed by the SAB as part of its review of the TSD. (SAB report available at: http://yosemite.epa.gov/sab/sabproduct.nsf/ea5d9a9b55cc319285256cbd005a472e/aaf67ae4dd199409852578cb006bcb04!OpenDocumeny)

Comment 17: Commenter 17621 states that with respect to the "hypothetical full scale IQ" this relatively small incremental change in IQ (0.18 on a 100-point IQ scale) associated with a 1 ppm Hg increase in hair cannot itself be measured for an individual, but must be estimated for the total population (through a series of analytical and exposure assumptions) to derive estimates at the national level (e.g., 510.8 IQ points saved in RIA, Table 5-7). The individual effects estimates for the "average" IQ loss per exposed child were defined out to the fourth or fifth decimal place (see RIA, Tables 5-6 and 5-7) to indicate the potential (and relatively) small effects across the different exposure scenarios.

Response to Comment 17: Although the EPA disagrees that the IQ results are too small to be important, the EPA acknowledges that IQ is not the most sensitive neurodevelopmental endpoint affected by methylmercury exposure. The EPA analysis of potential IQ loss from methylmercury exposure is for population effects, as is done for any quantitative estimate of risk. For precision, it is appropriate to use a large number of significant figures in calculation, if this is supported by the data inputs. Upon completion of calculations, the estimate is rounded to the number of significant figures reflective of the least precise term. In the case of IQ, based on the effect estimates from the underlying epidemiological studies and the exposure estimates, the level of precision is to 2 significant digits to the right of the decimal place.

The EPA's independent SAB recommended that the IQ analyses be retained but de-emphasized in the documentation underlying the final regulation (U.S. EPA-SAB, 2011). The SAB concluded, "The Panel does not consider it appropriate for EPA to use IQ loss in the risk assessment and recommended that this aspect of the analysis be de-emphasized, moving it to an appendix where IQ loss is discussed along with other possible endpoints not included in the primary assessment. Although the Panel agreed that the concentration-response function for IQ loss used in the risk assessment is appropriate, and no better alternatives are available, IQ loss is not a sensitive response to methylmercury and its use likely underestimates the impact of reducing methylmercury in water bodies." (U.S. EPA-SAB, 2011) The EPA is following the SAB recommendation by deemphasizing the IQ analysis and placing that analysis in an appendix to the revised TSD.

Comment 18: Commenter 17681 states that the EPA's IQ reduction metric, which it developed to assess the health impact from Hg emissions, resulted in an "aggregated benefit estimate" of 0.00209 IQ points lost, well below the level that can even be measured by an IQ test.

Response to Comment 18: The commenter is confusing a measurement based on an IQ test and the response predicted by the linear model the EPA used to calculate IQ decrements caused by methylmercury exposure. The EPA uses a linear response model to predict IQ loss due to methylmercury exposure because there is no literature to date that shows a threshold below which no effect is observed. The EPA notes that the average reduction in IQ loss reported in the RIA does not reflect the greater than average impacts that reduced exposure would have at the tails of the distribution. The SAB has supported the model used in the RIA analysis and states that "The support for the model of the relationship between IQ and methylmercury exposure comes from Axelrad and Bellinger (2007) and from a whitepaper produced by Bellinger (2005)." (SAB Report available at: http://yosemite.epa.gov/sab/sabproduct.nsf/ea5d9a9b55cc319285256cbd005a472e/aaf67ae4dd199409852578cb006bcb04!OpenDocument).

4. Impacts on Food.

Comment 19: Many commenters (15002, 15160, 16682, 17405, 17408, 17409, 17254, 17683, 17766, 18043, 18421, 18425, 18435, 18932, 17676, 17679, 17922) support this rulemaking because it will reduce the levels of methylmercury in the U.S. diet. These commenters consider the consumption of methymercury in contaminated fish to be a primary health concern and they believe that fish and shellfish are the main sources of human methymercury exposure. Commenter 18932 states that, as of 2008, all 50 states had issued some type of fish consumption advisory for Hg and 27 states had issued statewide Hg advisories for all bodies of water in the state. This commenter is also concerned that the number of fish consumption advisories is increasing, stating that between 2006 and 2008 the number of Hg advisories rose from 3,080 to 3,361. The commenter also notes that both the EPA and the Food and Drug Administration (FDA) issued a joint advisory urging women and children not to consume any shark, swordfish, king mackerel, or tilefish, and to limit white albacore tuna to one meal per week.

Response to Comment 19: The EPA agrees that ingestion of methylmercury in fish is the main route of exposure in the American diet and that consumption of fish by pregnant women and children above the levels suggested by the advisories issued by the EPA and FDA can increase the risk of adverse health effects.

Comment 20: Commenter 15160 reports that Hg from coal-fired power plants in North Carolina has contaminated food, leading to advisories in North Carolina covering 17 species of ocean fish, walleye, and bass. Commenter 17254 states that the U.S. Geological Survey has shown that one in four fish contain Hg levels that exceed recommended EPA criteria and also notes that a recent issue of the Environmental Health Perspectives recreational anglers have been shown to have higher hair mercury levels. Commenter 17405 notes that human fish consumption restrictions cover every one of Wisconsin lakes. Commenter 17408 notes that a study of seafood-eating populations on Faroe Islands in the North Atlantic has shown that teenagers who were exposed to Hg while still in their mother's womb have neurological and behavior problems. Commenter 17676 notes that frequent consumption of high-Hg fish has been associated with a number of harmful effects in adults, including effects on neurologic, cardiovascular, and immune systems. Commenter 18932 believes that residents in coastal areas may be exposed to unsafe levels of methylmercury because their diets are especially high in fish and shellfish. The commenter notes that a study in Alabama found extremely high levels of Hg in hair samples from coastal residents who consume seafood and fish every week, indicating elevated Hg levels in their bodies overall. In a 1993 study, the North Carolina Department of Health and Human Services discovered that fishermen and their families were consuming fish from the Waccamaw River that are under a fish advisory and that blood samples taken from this population had average Hg blood levels of 7.5 ug/L, with approximately 40% of those tested having blood Hg levels greater than the recommended 3.5 ug/L level for women of childbearing age. Commenter 17683 argues that families should be able to eat safe fish without having to worry about Hg in their bloodstreams and believes that regulation of Hg emissions from EGUs is overdue. Commenter 16682 states that the proposed rule can achieve reductions in Hg contamination in fish tissues quickly because levels of Hg in fish tissue quickly drop when the source is reduced. The commenter believes the proposed EPA standards will protect the public health and the environment.

Response to Comment 20: The EPA agrees that Hg from coal-fired power plants is a contributor to the levels of methylmercury in fish across the country and that consumption of contaminated fish can lead to increased risk of adverse health effects. The EPA agrees that this rule will reduce Hg levels in fish. The EPA agrees that, in some cases, Hg levels in fish can decrease quickly following reductions in Hg deposition. However, the time lag between reduced Hg deposition and reduced Hg levels in fish can vary greatly and is not accounted for in the RIA benefits analysis.

Comment 21: Commenters 15002 and 17679 believe the EPA's analysis underestimates the impact of Hg emissions because the analysis focuses only on populations who consume self-caught fresh-water fish. Commenters argue that the EPA should include the contribution to Hg exposures from other freshwater and saltwater fish, including those most likely to contain large amounts of Hg (such as king mackerel, swordfish, large tuna, and tilefish). Commenter 17620 states that the EPA's analysis is of limited usefulness in assessing the health impacts of the proposed rules because it is based on self-caught freshwater fish rather than on commercially caught freshwater fish and saltwater fish that constitute the vast majority of the fish consumption in the U.S.

Response to Comment 21: The EPA agrees that the analysis presented in the RIA is an underestimate of the benefits of reduced Hg exposure in part due to the exclusion of some fish species especially saltwater fish. The EPA did not include marine fish due to data and methodological limitations.

Comment 22: Some commenters (17702, 17732, 17620, 17751, 18023) believe that the EPA's analysis is not based on best available science, and that the analysis is flawed and overestimates the impact of Hg emissions on human health. Commenter 17751 argues that the EPA failed to fully account for the role of dietary selenium's protective effects against methylmercury toxicity. This commenter states that there is extensive literature on the beneficial role of dietary selenium and that this literature shows that the binding affinity of Hg for selenium is up to a million times higher than for sulfur (Hg's second best binding partner). In support of their argument, this commenter quotes work completed by an EPA-funded study showing that 97.5% of freshwater fish analyzed for a Western U.S. survey have sufficient selenium to "potentially protect them and their consumers against Hg toxicity."

Response to Comment 22: The EPA disagrees with the commenters that the best available science was not used to generate the estimates presented in the RIA. There are uncertainties in the analysis; one of which is the role of selenium. The EPA was not able to quantify this relationship within the benefits estimates due to data and methodological limitations. There remains uncertainty with respect to the nature and magnitude of potential confounding between selenium and methylmercury and the associated effects on childhood neurodevelopment due to maternal ingestion during pregnancy. Additional research is needed to provide further clarity on this issue, but recent studies such as those referenced above reinforce the view that fish consumption during pregnancy should be approached as a case of multiple exposures to nutrients and to methylmercury, with a complex and potentially interactive set of risks and benefits related to infant development. The EPA SAB Mercury Review Panel, in their peer review of the EPA's National Scale Mercury Risk Assessment, evaluated the role of selenium in affecting Hg risk, and there was no consensus on the effects of selenium. The panel agreed that for all fish nutrients, there is not sufficient information to recommend a quantitative adjustment in health endpoint measures.

Comment 23: Commenters 17751 and 17681 argue that an analysis by Soon (See, Scientific Critique of EPA's EGU MACT and NSPS Revisions, Willie Soon, PhD, June 2011) identifies a number of material errors in the EPA's analysis of the health concerns related to Hg emissions from coal-fired EGUs. Commenter 17751 notes that Soon's analysis and various other peer-reviewed scientific studies indicate that regulatory management of Hg is likely impossible, because methylmercury bioaccumulation and methylation are driven by factors others than elemental Hg availability. The commenter believes that Soon's analysis clearly indicates that Hg emissions and impacts from sources other than those derived from EGUs greatly exceed the EGU emissions and impact and that even total elimination of all industrial emissions, inclusive of those from power plants, will not affect trace or even high methylmercury levels that have been found in fish tissue over century-long time periods. The commenter concludes that fish consumption advisories as an exposure prevention strategy make more sense than emissions control strategies.

Response to Comment 23: The EPA disagrees that regulatory management of EGU emissions of Hg is impossible and is proposing the MATS rule that will lead to reductions of Hg emissions from EGUs. The National Scale Mercury Risk Assessment shows that changes in Hg emissions from 2005 to 2016 are in fact likely to result in reductions in U.S. EGU attributable fish-tissue Hg concentrations. The EPA notes that decisions related to Hg emission controls are distinct from decisions about fish consumption advisories, which are intended to provide information to potential fish consumers. To the extent that regulations on EGU Hg emissions reduce concentrations of Hg in fish, specific fish consumption advisory information will reflect those changes in Hg concentrations.

Comment 24: Commenter 17751 disagrees with the EPA's statement that reductions in power plant emissions will likely result in a reduction in Hg concentrations for fish in the ocean. Commenter 17751 states that much valid, peer-reviewed scientific research has demonstrated that methylmercury in the world's oceans is not controlled by deposition of atmospheric Hg. As an example, the commenter discusses studies by Morel, et al. ("Response to Comment on Sources and Variations of Mercury in Tuna" Kraepiel, A. M. L.; Keller, K.; Chin, H. B.; Malcolm, E. G.; Morel, F. M. M.; Environmental Science Technology; 2004; 38(14); 4048-4048 (DOI: 10.1021/es0404217)) that show that Hg levels in tuna caught in the region around Hawaii have not changed over a period during which anthropogenic Hg inputs in the region have increased. The study's authors suggest that these findings "provides prima facie evidence that this concentration is not responding to anthropogenic emissions irrespective of the mechanisms by which mercury is methylated in the oceans and accumulated in tuna." This commenter further states that the world's oceans contain 40–200 million tons of Hg and that very little of it has been converted into methylmercury that can be accumulated in fish and that eliminating all of the 105 tons of Hg emissions released from U.S. anthropogenic sources in 2005 will leave the levels of Hg in the world's oceans virtually unchanged with a 0.0003 % reduction. Further, the commenter states that the primary source of exposure to methylmercury for most people living in the U.S. is through consumption of ocean fish and that exposure to methylmercury from freshwater consumption is statistically insignificant, as less than 0.05% of total fish and fish products consumed annually in the U.S. are freshwater fish (Food and Agriculture Organization of the United Nations, Trade in Fish and Fish Products, Fish Consumption, Fishers and Fleet Information, Tables CM 1.1 and CM 1.2).

Response to Comment 24: The EPA disagrees that U.S. Hg emissions do not contribute to the global pool of Hg or affect Hg concentrations in ocean-going fish. The NAS in its 2009 report Global Sources of Local Pollution: An Assessment of Long-Range Transport of Key Air Pollutants to and from the United States http://www.nap.edu/catalog/12743.htmlreport, explains that "Hg is truly a global pollutant, as it has the potential, once emitted from any source, to be transformed to different chemical forms, transported through the atmosphere, and deposited long distances from the point of origin. Reservoirs that accumulate Hg include the atmosphere, the oceans, freshwater systems, soils, biota, and the cryosphere. Hence intercontinental transport is an important process that clearly affects U.S. exposures. Continued emissions will increase the amount of Hg in the global pool available for longrange transport and recycling among these reservoirs in the environment." Thus since the oceans are considered a sink for Hg pollution it is reasonable to conclude that marine fish would be affected by that exposure.

Hg accumulation in fish is dependent on many variables including the age and weight of the fish. Additionally, Hg concentrations are variable across the oceans with methylated Hg accounting " for up to 29% of the total Hg in subsurface waters (average 260 ± 114 fM). We observed lower ambient methylated Hg concentrations in the euphotic zone and older, deeper water masses, which likely result from decay of MeHg and Me2Hg when net production is not occurring "(Sunderland,2009).

That being said, the RIA is a national scale assessment which focuses on the exposures to methylmercury in populations who consume self-caught freshwater fish (recreational fishers and their families). Although there are other routes of exposure, including self-caught saltwater fish and commercially purchased fresh and saltwater fish, these exposures are not evaluated because 1) for self-caught saltwater fish, we are unable to estimate the reduction in fish tissue methylmercury that would be associated with reductions in Hg deposition from U.S. EGUs, and 2) for commercially-purchased ocean fish, it is very difficult to determine the source of the methylmercury in those fish, and thus we could not attribute Hg levels to U.S. EGUs.

Comment 25: Commenter17751 disagrees with the EPA assessment of a direct one-to-one proportional relationship between reductions in atmospheric Hg and methylmercury concentrations in fish. The commenter believes this to be one of several errors that grossly inflate the EPA's estimates of the human health benefits of the proposed controls on Hg emissions by EGUs and asserts that any health benefits from the EGU MACT would occur at times far removed from the time at which reductions in emissions occur.

Response to Comment 25: The EPA disagrees that the health benefits of Hg control are inflated. In fact the EPA believes that the estimates presented in the RIA are an underestimate because the EPA was not able to analyze the impacts using the most sensitive endpoints for human health. According to the SAB's review of the TSD for this rule "The loss of IQ points is likely to underestimate the impact of reducing methyl mercury in water bodies. The reason is that IQ score has not been the most sensitive indicator of methylmercury's neurotoxicity in the populations studied. As noted in the TSD, in the Faroe Island study the most sensitive indicators were in the domains of language (Boston Naming), attention (continuous performance) and memory (California Verbal Learning Test), neuropsychological tests that are not subtests of IQ tests and are not highly correlated with global IQ. In the Seychelles study, the Psychomotor Development Index has been most sensitive measure and, while this is a component of the Bailey Scales of Infant Development, it is not highly correlated with cognitive measures."

Further, the EPA disagrees that the proportionality assumed in the MMAPS model that relates the reduction in Hg deposition to reductions in fish tissue concentrations is inappropriate. According to SAB

"Since the Mercury Maps approach was developed, several recent publications have supported the finding of a linear relationship between mercury loading and accumulation in aquatic biota (Orihel et al., 2007; Orihel et al., 2008; Harris et al., 2007). These studies suggested that that mercury(II) deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. These results substantiate that the assumption of proportionality between air deposition changes and fish tissue methylmercury level changes is sufficiently robust for its application in this risk assessment."

The EPA does agree that there may be a lag time between evidence of health benefits due to the reduction of Hg emissions and the actual occurrence of the reductions however there is no data available on how long that lag may be.

Comment 26: Commenter 17751 believes that the EPA should not have relied on Faroe Islands study because the Faroe Islanders receive Hg exposure by atypical consumption of pilot whale meat contaminated by PCBs which has little relationship to fish consumption in the U.S. This commenter asserts that the EPA should have used data from the Seychelles Islands study, because this study is the most relevant to the U.S., where there was no adverse response observed in women or their children despite maternal Hg levels 10 times those found in the U.S. Commenter 17751 also notes that (1) Seychelles islanders consume far more fish than do Americans; (2) the amount of methylmercury in the U.S. population is 10 to 20 times below that of the Seychelles islanders; and (3) all ocean fish throughout the world contain about the same amount of methylmercury, so, per fish meal, there is no difference in methylmercury intake when comparing the seafood diet of Americans to Seychelles islanders. Commenter 17751 believes that the Seychelles Islands study is the right study to use as a basis for making a regulatory decisions and assessing the health impacts of Hg.

Response to Comment 26: The comment has several inaccurate statements. As published by Dr Weihe and colleagues, exposure to methylmercury in the Faroes was largely from consumption of pilot whale meat; exposure to PCBs was found in the portion of the population who also consume whale blubber. The lipophilic PCBs are found in the fat compartment of the pilot whales; methylmercury, by contrast, is bound covalently to protein in the whale meat.

Contemporary publications on data and analyses from the Seychelles Child Development Study of Methylmercury from Fish Consumption (SCDS) have reported methylmercury-related effects from testing of older children in their study cohort (e.g., van Wyngaarden et al. 2006; Strain et al., 2008.)

The EPA's RfD for methylmercury is based on multiple endpoints from the three extant large studies of childhood effects of *in utero* exposure: Faroes, New Zealand, and an integrative measure including data from Seychelles. Documentation for the choices underlying calculation of the RfD can be found in the following sources: U.S. EPA (2001) *Water Quality Criterion for the Protection of the Human Health: Methylmercury*EPA-823-T-01-001, available at http://water.epa.gov/scitech/swguidance/standards/criteria/aqlife/pollutants/methylmercury/index.cfm; U.S.EPA. 2011.Integrated Risk Information System, available at http://www.epa.gov/iris/subst/0073.htm; Rice et al (2003).

5. Impacts on low-income and subsistence populations.

Comment 27: Multiple commenters (15002, 16122, 17409, 17254, 17732, 17766, 17811, 18421, 18435, 18436, 18487, 18932) note that Hg emissions have a disproportionate impact on low-income and subsistence populations, such as Native Americans, Hispanics, and Location subsistence fishers. Several commenters (17409, 18421, 18932) state that African Americans, Native populations, Latino communities, Asian Americans (e.g., Vietnamese in the gulf area), and other low income communities who fish recreationally are more likely to eat the fish they catch. Commenter 17766 states that African Americans and Hispanics eat more fish that are contaminated with Hg than are their White counterparts because these groups eat fish to obtain a source of high quality protein and catch the fish themselves to make up for economic inequities. This commenter quotes 2006 statistics showing that approximately 1.4 million African Americans and 1.3 million Hispanics were avid subsistence anglers. This commenter further notes that many of these disadvantaged groups fish in urban areas near where they live because they have limited transportation options and therefore, tend to fish in urban areas where fish are most Hg-laden. Commenter 18932 quotes a 2005 survey of anglers in Baltimore Harbor, the District of Columbia, and the Tidewater Region of Virginia where interviewers found that in many instances anglers stated that they knew of health advisories associated with the fish that they caught, but still ate the fish and shared them with at-risk members of their families, e.g., women of childbearing age. In the Tidewater Region of Virginia, the study showed that 91% of those interviewed stated that they ate some of the fish they caught, 50 % of stated that having a fresh fish dinner was a very important motivation for fishing, and 19% stated that reducing the cost of food was a very important motivation for fishing.

Response to Comment 27: The EPA agrees that low-income and subsistence fishers are disproportionately affected by exposure to methylmercury in fish due to their fish consumption patterns.

Comment 28: Commenter 17254 notes that African Americans are disproportionately affected by Hg emissions because this population have a greater prevalence of kidney disease and are more likely to reside in closer proximity to industries that emit Hg and other air pollutants. Commenter 18435 provides maps of the southeastern states showing the proximity between concentrations of low income people, including both white and African-Americans, and the location of coal-fired power plants and notes that the close proximity of these plants to waterways near their homes makes it more likely that fish from those waterways would make part of their diet. Commenter 15002 notes that the EPA's analysis concluded that a child born to an African-American woman in 2016 who consumed fish at the 90th percentile would experience a loss of approximately 7.7 IQ points in the absence of the proposed rule. This commenter stated that this risk represents an unacceptable burden on this population.

Response to Comment 28: The EPA agrees that low-income African Americans are at greater risk of adverse health outcomes due to their higher consumption rates of fish with high levels of methylmercury. The EPA agrees that this risk is and unacceptable burden for this population.

Comment 29: Commenter 17732 acknowledges that there are subpopulations of Native Americans more susceptible to methylmercury exposure because of subsistence diets based on fish and notes that the 1997 Mercury Study to Congress concludes that exposures among specific subpopulations including anglers, Asian-Americans, and members of some Native American Tribes may be more than two-times greater than those experienced by the average U.S. population. However, this commenter believes that fish consumption is limited and occurs primarily during recreational activities. Commenter 17732 notes that a 2004 U.S. Fish & Wildlife report concluded that the Navajo "can and should feel comfortable about consuming fish on a recreational basis…" and further argues that the EPA should not assume that exposure to Hg and other HAP on Tribal lands are equal in comparison to exposures in the more densely populated metropolitan and urban areas where population and industrial growth continue to contribute to hazards to public health and environment. The commenter further recommends the EPA collect more public health data in areas in close proximity to regional HAP so as to better understand the true public health and environmental impacts.

Response to Comment 29: The EPA agrees that the analyses presented in the RIA focused on Native American populations with high-end fish consumption patterns specifically the Great Lakes tribes of Chippewa and Ojibwe whose consumption patterns may constitute a higher risk of adverse health effects. The people of the Navajo nation were not included in the modeled populations for the risk assessment or the RIA for this rule. The EPA acknowledges that some Native American populations do not fit the criteria for subsistence level fishers.

6. Impacts on tourism and recreational fishing.

Comment 30: Commenters 16122 and 17732 note that Hg contamination of streams, rivers, and lakes threaten the economy of states and tribes that rely on fishing tourism. Quoting data published by the U.S. Department of Interior, Fish and Wildlife Service, commenter 16122 notes that the Wisconsin Department of Natural Resources sells approximately 1.5 million fishing licenses and that the sales of these licenses, as well as of food, lodging, gasoline, and sporting equipment related to fishing adds approximately $2.1 billion to the Wisconsin economy and another $5 billion to the states of Illinois, Indiana, Michigan, Minnesota, and Ohio.

Response to Comment 30: The EPA agrees that Hg contamination of water bodies across the U.S. has led to fish consumption advisories for those water bodies that may have a negative effect on recreational fishing. The EPA also agrees that recreational fishing has a large economic impact in many states. The EPA further agrees that reducing Hg levels in fish should have beneficial effect on recreational fishing. However, given data methodological limitations, the EPA was not able to estimate those benefits at this time.

7. Impacts on wildlife.

Comment 31: Multiple commenters (17679, 18033, 18043, 18248, 18487, 18541, 19214) point out that Hg emissions have adverse health effects for numerous species of wildlife, including reproductive, neurological, survival, and behavioral effects.

Response to Comment 31: The EPA agrees that Hg exposure in wildlife is responsible for various adverse health effects in many species across the U.S. and recognizes that research is ongoing in this area. The benefits to ecological health remain unquantified in the assessments for this rule due to data and methodological limitations. Because these benefits are unquantified, the benefits assessment presented in the RIA for this rule is underestimated and conservative.

8. Benefits do not justify the rule.

Comment 32: Multiple commenters (17716, 17682, 18484, 18500, 17904, 18020, 17754) argue that the benefits of the proposed rule do not justify the costs.

Response to Comment 32: The EPA disagrees that the benefits of the MATS rule do not justify the costs. As the analyses presented in the RIA for the rule show the benefits outweigh the costs by a large margin. Although the monetized benefits of reducing Hg emissions are not large, those benefits are also not equally distributed across the population. As the sensitivity analysis shows, some populations including low-income African Americans and some Native American populations may receive a disproportionate benefit, and the distributional aspects of the benefits may help to justify the costs of the rule. Furthermore, the analysis depended on using a less sensitive endpoint (IQ) of neurological impacts of Hg exposure as noted by the SAB which leads to underestimation of the benefits. Additionally, many other impacts of Hg emissions were not quantified including impacts on ecosystems and wildlife; especially fish, birds (both fish and insect eating), and mammals. Other HAP controlled by the MATS rule were likewise not quantified due to data, resource and methodological limitations. Even if we were able to fully monetize the public health benefits of reducing exposure to Hg and other HAP, it is likely that the PM benefits would continue to dominate the total monetized benefits due to the size of the exposed population and the severity of the associated health effects. Despite our inability to provide monetized benefits of HAP emission reductions, the total monetized benefits exceed the estimated costs of the rule by a substantial margin, even when taking uncertainty into account.

Consideration of $PM_{2.5}$ health co-benefits expected as a result of direct $PM_{2.5}$ and SO_2 emission reductions is directed by OMB Circular A-4 (p. 26, available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/):

"Your analysis should look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks. An ancillary benefit is a favorable impact of the rule that is typically unrelated or secondary to the statutory purpose of the rulemaking (e.g., reduced refinery emissions due to more stringent fuel economy standards for light trucks) while a countervailing risk is an adverse economic, health, safety, or environmental consequence that occurs due to a rule and is not already accounted for in the direct cost of the rule (e.g., adverse safety impacts from more stringent fuel-economy standards for light trucks)."

It is also directed by EPA's Guidelines for Preparation of Economic Analyses (p. 11-2, available at: http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html):

"An economic analysis of regulatory or policy options should present all identifiable costs and benefits that are incremental to the regulation or policy under consideration. These should include directly intended effects and associated costs, as well as ancillary (or co-) benefits and costs."

In line with this guidance, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible. We further note that if we were able to fully monetize all of the benefit categories, the benefits would exceed the costs by an even greater amount than we currently estimate.

9. Lack of quantification of non-Hg HAP means no benefits.

Comment 33: Commenter 17716 believes that the fact that the benefits of non-Hg HAP are not quantified means that no benefits exist for these reductions.

Response to Comment 33: This rule is expected to achieve important non-Hg HAP benefits. However, monetization of non-Hg HAP benefits is limited by currently available data and methods. In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAP anticipated to be reduced by these rules. The EPA disagrees that the health benefits of non-Hg HAP could never be measured. A well-designed epidemiological study could measure these benefits. The EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk. Quantitative estimates of these benefits are provided to the extent possible, and our limited ability to monetize these benefits does not indicate that they are non-existent or less important.

Our treatment of these benefits follows guidance set by OMB Circular A-4 (pp. 26-27, available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/):

“Sound quantitative estimates of benefits and costs, where feasible, are preferable to qualitative descriptions of benefits and costs because they help decision makers understand the magnitudes of the effects of alternative actions. However, some important benefits and costs (e.g., privacy protection) may be inherently too difficult to quantify or monetize given current data and methods. You should carry out a careful evaluation of non-quantified benefits and costs. Some authorities refer to these non-monetized and non-quantified effects as “intangible.”

It is also in line with EPA’s Guidelines for Preparing Economic Analyses (p. 11-3, available at: http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html).

“Benefits and costs that cannot be monetized should, if possible, be quantified (e.g., expected number of adverse health effects avoided). Benefits and costs that cannot be quantified should be presented qualitatively (e.g., directional impacts on relevant variables).”

10. MATS is duplicative of the CSAPR and multiple NAAQS.

Comment 34: Commenter 17761 believes that MATS will duplicate emissions reductions achieved through the CSAPR and NAAQS implementation.

Response to Comment 34: The EPA disagrees that MATS is duplicative with the CSAPR and NAAQS. MATS will reduce emissions of HAP emissions not regulated by the aforementioned rules. Furthermore when the EPA estimates the benefits for rules like MATS, the EPA includes other rules such as the CSAPR in the “baseline.” Any emission changes expected as a result of MATS are additional emission reductions beyond those regulations (e.g., CSAPR) that were considered to be part of the baseline.

11. U.S. EGU mercury emissions are a small contributor to the global pool.

Comment 35: Multiple commenters (17716, 17682, 18484, 18500, 17904 18020, 17754) argue that reductions of Hg emissions from U.S. EGUs is not a cost-effective method for reducing Hg emissions since Hg is emitted globally and the contribution from U.S. sources is very small.

Response to Comment 35: The EPA disagrees that controlling Hg emissions from U.S. EGUs is not a cost-effective method of reducing Hg emissions. The EPA agrees with NACAA (public comment EPA-HQ-OAR-2009-0234-17620-A1) that “while a global mercury pool does exist, data collected at a number of U.S. locations over the past decade show that reductions in point source air emissions of mercury produce substantial improvement in the local and regional environment shortly after those reductions are implemented. Indeed, ongoing monitoring efforts in a number of states indicate that mercury levels in fish and other biota have fallen as those states have begun to address sources of mercury pollution.”

In November, 2002, an enhanced air monitoring site was established in Steubenville, Ohio to investigate source-receptor relationships for Hg deposition in eastern Ohio. The site overlooking the Ohio River was in close proximity to several anthropogenic point sources, including EGUs. The data collected during this study demonstrated that approximately 70% of the Hg in wet deposition was due to coal combustion and that a significant portion of the Hg deposited in the immediate vicinity of local EGUs was directly attributed to those local sources. The University of Michigan researchers concluded that "it has become evident that near-field impact of coal fired utility boilers on Hg deposition is significant and underestimated by the models that have been utilized in previous policy decision making."(Keeler et al, 2006) Similarly, wet deposition data collected throughout the Great Lakes over the past decade have demonstrated distinct regional variability that undercuts any suggestion that local Hg emission efforts are of no value. Precipitation samples collected in southeastern Michigan showed a 25 to 35% increase in the Hg concentration between urban sites in Detroit and a rural site 40 miles to the east. This phenomenon is not limited to the northern part of the country. Studies in south Florida revealed that the spatial and temporal patterns of wet deposited Hg were also strongly influenced by local sources. National data show similar variability in deposition rates; Hg deposition rates attributable to U.S. EGU emissions at the most affected water bodies are eight times the mean rate of such deposition. The EPA's modeling suggests that the proposed rule will reduce this local excess deposition from U.S. EGUs by 80%. (Gerald J. Keeler, Matthew S. Landis, Gary A. Norris, Emily M. Christianson, and J. Timothy Dvonch**,** *Sources of Mercury Wet Deposition in Eastern Ohio, USA,* pub *Environ. Sci. Technol.*, 2006, *40* (19), pp 5874–5881.)

12. HCl contribution to acidification of ecosystems.

Comment 36: Commenter 18487 points out that reducing emissions of acid gases will benefit acid sensitive ecosystems and the fish and wildlife that depend on those ecosystems.

Response to Comment 36: The EPA agrees that acidification poses a significant risk of adverse effects to fish and wildlife in aquatic and terrestrial ecosystems. Please refer to the EPA's recent Risk and Exposure Assessment for Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur-Main Content (Final Report available at http://www.epa.gov/ttn/naaqs/standards/no2so2sec/data/NOxSOxREASep2009MainContent.pdf) for a comprehensive report on those effects including increased Hg methylation in acidified systems. To the extent that acid gases contribute to acidification, the EPA agrees that those gases pose a risk for acidification of ecosystems. However, due to data and methodological limitations, the EPA was not able to quantify those risks and benefits.

6M - Impacts and Costs: Air quality co-benefits modeling

Commenters: 17627, 17752, 19686

Comment 1: Commenter 17627 states that the 2005 base year did not include emission reductions that have already occurred as a result of many enforceable federal and state programs. Additionally, the 2016 emissions are predicated off the IPM-related NODA dated October 2010 and do not include results from two subsequent NODAs. If the emission estimates were corrected, the benefits would not be overstated and it is possible that the rule could not be justified on cost considerations.

Response to Comment 1: The EPA disagrees with the commenter's assertion that the benefits are overstated based on a 2005 base year. The benefits of the rule are computed based on differences between the 2016 baseline and the 2016 policy case, and not the differences from 2005. Therefore, to achieve reasonably accurate estimates of benefits, the most important feature of EPA's approach is having an accurate projection from 2005 to 2016, so that the emissions reductions and economic downturn referenced by the commenter are included in the future base and therefore not included as part of the benefits of the rule. These impacts are included in both the 2016 baseline and the 2016 policy case and therefore are not captured as benefits of the rule. The EPA diligently included the emissions reductions that have occurred from 2005 to present and the final modeling done for the RIA for this rule is the best available national information to reflect reductions in emissions that have occurred from 2005 to present. The data used at proposal were updated to reflect the comment process on the CSAPR, for which a number eastern states provided detailed updates to the EPA's emissions projection assumptions for EGU, non-EGU point, stationary area, and nonroad mobile sources. All of these comments were included in the projections used for the final rule. Furthermore, the comment process for this rule provided an opportunity to make the EPA aware of any other projection changes that were needed for improving our benefits estimates. In the rare instances where such specific comments were made for this rule, the EPA included those reductions in the final 2016 projections. The EPA used the best economic forecasts available at the time the datasets were created. This included the use of Annual Energy Outlook of 2010 data in the EGU projections. Other updates to point sources included the incorporation of all known controls in the 2016 baseline, and the inclusion of non-EGU plant closures, federally enforceable emissions reductions, and consent decrees that have happened since 2005.

Comment 2: Commenter 17752 describes errors found in the IPM file pertaining to two of the commenter's units which are affected by the proposed rule. The commenter explains that the Big Stone Plant was shown to have an on-line scrubber in 2011, which it does not. The file also showed an ESP, while the plant has only a fabric filter and not an ESP. The commenter also explains that the Hoot Lake Plant Unit 2 does not have any NO_X control listed in the file, but it is equipped with low NO_X burners and overfire air. The commenter requests the EPA make corrections to these and any other incorrect IPM files and determine the true rule impacts.

Response to Comment 2: The EPA thanks the comment for this observation and notes that IPM modeling for the final rule has been updated to reflect these corrections.

Comment 3: Commenter 19686 states that the rule's technical analysis fails to account for Tribes with respect to monitoring and modeling. The EPA used the Community Multi-scale Air Quality (CMAQ) model to estimate the rule's reduction in the incidence of adverse health effects, as well as the estimated economic value of the reduction in the incidence of adverse health effects. The grid sizes used fail to account for the considerable variation in the land size of individual Tribes, which can be anywhere between one to thousands of acres. The smallest lands, because of their size, may be wholly or partially located in areas that heavily influence airflow unlike surrounding jurisdictions (*e.g.,* valleys, mountains), meaning that CMAQ grid sizes of 12 km and greater may have a hard time modeling the true effects on local air quality for Tribes. To predict the rule's impact on Tribes more accurately, the commenter recommends that the EPA redo its CMAQ analysis and use modeling grids no greater than 4 km. Further, the EPA should use similar size grids for any of its forthcoming rules that may have potential impacts on Tribes.

In using the CMAQ model, the EPA cites as one uncertainty the "[l]ack of ozone and PM 2.5 monitors in rural areas" that required the EPA to extrapolate "observed ozone data from data to rural areas." Most of Indian Country is located in rural areas, meaning that their lands were unrepresented by the modeling results. Tribal lands located in urban areas are also largely unrepresented since they possess few monitors to discern the presence and amount of pollutants covered by the rule. Hence, the EPA lacks the data to make any accurate conclusions about the rule's impact on Tribes. Further, the EPA must get away from the practice of extrapolating data for Tribal lands for any of its rules and actions.

Response to Comment 3: The EPA agrees with the commenter that the CMAQ modeling with 12 km grid resolution may provide a lower bound estimate on EGU contribution as higher impacts using finer grid resolution are possible. The EPA also agrees with the commenter that there may be some variation in estimated air quality within a 12 km grid cell, but we believe the air quality estimates at 12 km generally reflect the area within the grid cell. The EPA would like to point out that the application of a photochemical model at 12 km grid resolution for the entire continental U.S. is more robust in terms of grid resolution and scale that anything published in literature and represents the most advanced modeling platform used for a national Hg deposition assessment.

6N - Impacts/Costs: Other/Miscellaneous

Commenters: 15002, 15160, 17620, 17884, 17973, 19214

Comment 1: Commenter 15002 recommends the EPA implement a 5-year review cycle for Hg and other HAP, similar to what is mandated by the CAA for the NAAQS. The commenter notes that emissions will plateau at current levels due to population increases balanced out by improved emission controls that become more effective and less expensive. However, the commenter also points out that no safe level exists for Hg or other HAP.

Response to Comment 1: The EPA welcomes the commenter's observations regarding future emissions levels and control technology but notes that, while a regular 5-year review schedule is mandated by the CAA for the NAAQS, the schedule prescribed by the CAA for review of emission standards for Hg and other HAP calls for a review every 8 years. See CAA section 112(d)(6). The EPA believes that subsequent periodic reviews will identify any improvements in techniques for the control of Hg and other HAP, and these will be incorporated as appropriate.

Comment 2: Commenter 17620 asks that the final rule reach a balance between protecting public health and avoiding unnecessary costs on the regulated community. The commenter notes that the EPA has projected substantial reductions in the emissions of Hg, HCl, fine PM and SO_2, all of which are needed to protect public health. The commenter further notes that industry testing supports emission standards of the stringency proposed and the technology to meet the proposed standards has been in use for 10 to 40 years.

Response to Comment 2: The EPA agrees with the commenter's assessment that the rule achieves important reductions in the emissions of several air pollutants without being unduly burdensome.

Comment 3: Commenter 15160 sees the proposed rule as an important step toward ensuring that the living and working environments of all Carolinians are reasonably safe and encourages the EPA to maintain the same level of strictness in the final rule.

Response to Comment 3: The EPA thanks the commenter for their support.

Comment 4: Commenter 17884 sees the proposed rule as having little, if any, health benefit and believes it may endanger public health and welfare by reducing the disposable income of people for the necessities of life.

Response to Comment 4: The EPA does not agree with the commenter's assertion that the rule will achieve little or no health benefit, and the EPA's position is supported by information on the benefits of the rule documented in the rulemaking record. The commenter also makes an assertion which relies on a theory that the cost of a rule will result in lost income that will, in turn, result in negative health effects that offset the positive health effects of the rule. (This is sometimes referred to as a "health-health tradeoff.") The EPA also disagrees with this claim and notes that there are a number of conceptual and empirical problems with any attempt to quantify the health-health tradeoffs of regulatory action to control air pollution. Claims about health-health trade-offs rely on questionable applications of cross-sectional data and ignore key factors that may influence changes in population health risks. Additionally, marginal decreases in household income caused by the pass-through costs of the regulation are unlikely to cause large changes in any single aspect of household spending, such as health care. These analyses also fail to consider that household income may increase if individuals are able to work (or work more) as a result of improved health, offsetting some or all of the pass-through costs of the rule. For these and other reasons, the EPA's science and economic peer review panels have consistently advised against incorporating alleged health-health trade-offs in EPA analyses of regulatory effects.

Comment 5: Commenter 17973 states that the fleet of coal-fired EGUs in the U.S. is aged and inefficient, having operated in most cases without modern controls for 35 years or more. The commenter considers the proposed rule to be overdue, as all other major source categories of HAP have implemented controls under MACT requirements already. The commenter believes that a well-controlled EGU equipped with a baghouse, SO_2 scrubber and SCR can meet the proposed standards.

Response to Comment 5: The EPA thanks the commenter for their support.

Comment 6: Commenter 19214 believes HAP emissions reductions beyond present levels are needed for the U.S. to fulfill the mission under the National Park Service Organic Act to protect national parks in an unimpaired condition for future generations.

Response to Comment 6: The EPA agrees with the commenter's statement that HAP reductions will have a positive environmental impact in addition to the health benefits quantified for this regulation.

Comment 7: Commenter 19686 states that to better assess the impact of the rule and any forthcoming actions by the EPA, they recommend that the EPA provide Tribes with an appropriate number of monitors of various types to establish baseline monitoring data for criteria pollutants and HAP.

Response to Comment 7: The agency encourages interested tribes to work with the EPA Regional Offices to determine where monitoring would be appropriate, as monitoring resources are typically supported with state and tribal air grants.

Comment 8: Commenter 16849 states that even under revised averaging periods, TRONA and DSI is not a viable option, as is incorrectly stated by the EPA ("IPM Parsed Results - Policy Case," Unplanned DSI Installations by 2015 includes Asbury: 2076_B_1).

Response to Comment 8: The EPA believes that DSI has the potential to be a useful and cost-effective control technology option for many units. We also understand that it is not an appropriate option for all facilities. Overall the EPA believes that the technology is most applicable for units burning lower-sulfur content coal (including, potentially, low-sulfur bituminous coal).

Comment 9: Commenter 17884 states that the EPA erred by failing to consider the negative health and welfare consequences of its proposed rule. According to the commenter, the proposed rule will have little, if any, health benefit and will endanger the public and welfare by reducing the disposable income people will have for the necessities of life. Because the purpose of the CAA is to protect public health and welfare, failure to consider the negative health consequences is arbitrary and capricious and otherwise not in accordance with law. *See AT&T Corp. v. Iowa Utils. Bd.*, 525 U.S. 366, 388 (1999) (invalidating agency interpretation not "rationally related to the goals" of the governing statute).

Response to Comment 9: The EPA disagrees with the commenter that our interpretation of the statute is in error for the reasons set forth in the proposed rule and this final action. The EPA also does not agree with the commenter's assertion that the rule will achieve little or no health benefit, and the EPA's position is supported by information on the benefits of the rule documented in the rulemaking record. The commenter also makes an assertion which relies on a theory that the cost of a rule will result in lost income that will, in turn, result in negative health effects that offset the positive health effects of the rule. (This is sometimes referred to as a "health-health tradeoff.") The EPA also disagrees with this claim and notes that there are a number of conceptual and empirical problems with any attempt to quantify the health-health tradeoffs of regulatory action to control air pollution. Claims about health-health trade-offs rely on questionable applications of cross-sectional data and ignore key factors that may influence changes in population health risks. Additionally, marginal decreases in household income caused by the pass-through costs of the regulation are unlikely to cause large changes in any single aspect of household spending, such as health care. These analyses also fail to consider that household income may increase if individuals are able to work (or work more) as a result of improved health, offsetting some or all of the pass-through costs of the rule. For these and other reasons, the EPA's science and economic peer review panels have consistently advised against incorporating alleged health-health trade-offs in EPA analyses of regulatory effects.

CHAPTER 7: STATUTORY AND EXECUTIVE ORDERS

7A - Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Commenters: 17638, 17648, 17681, 17702, 17713, 17715, 17721, 17734, 17751, 17757, 17758, 17768, 17806, 17842, 17833, 17868, 17884, 17911, 17917, 17919, 18016, 18018, 18446, 18486, 19042, 19114

1. The EPA did not comply with EO 13563.

Numerous commenters (17638, 17681, 17702, 17713, 17715, 17721, 17751, 17757, 17758, 17842, 17868, 17884, 17911, 17917, 17919, 18106, 18018, 18446, 18486, 19042, 19114) state that the EPA failed to comply with the requirements of EO 13563.

Comment 1: Multiple commenters (17638, 17713, 17884, 18446, 18486, and 19114) state that the EPA failed to consider the cumulative impacts of the proposed rules as required by EO 12866 and EO 13563. Commenter 17638 states the regulation's benefits do not justify its costs nor impose the least burden on society taking into the costs of cumulative regulations. Commenter 17884 believes the EPA is producing a series of rule-by-rule RIAs that narrowly define what impacts the specific rule at issue has, which has the result of minimizing the impact of any one rule and avoiding taking responsibility for the actions utilities are taking in anticipation of the EPA's entire regulatory agenda. Commenter 18446 cites a report by the National Economic Research Associates (NERA) that shows that the combination of the Transport Rule and the Utility MACT Rule will be a serious blow to the economy, causing a net loss of 1.4 million jobs by 2020, and the combination of the two regulations will also cause a substantial increase in retail electricity prices, with the price increase estimated to top 23 % in some areas of the country. Commenter 18446 suggests the EPA withdraw the rule until the agency conducts a cumulative impact analysis.

Commenter 17715 suggests the proposed rule does not take into account harmonization with other regulations, such as the effect of this rule coupled with future requirements surrounding Coal Combustion Residuals (CCR), revised NAAQS, regulations surrounding cooling water intake impingement and entrainment (316(b)) and GHG regulations that will also be affecting sources in upcoming years.

Commenter 17734 states that there are a large number of related rulemaking efforts coming out in the near term, including revisions to the NAAQS for $PM_{2.5}$, ozone, and 1-hour SO_2; a new GHG NSPS; and the recently promulgated CSAPR, which will make it difficult for implementing agencies and affected facilities to determine the most efficient use of resources to allocate in order to cost-effectively achieve compliance. The commenter suggests that if the agency can coordinate, reconcile, and harmonize the overlapping regulatory requirements, it will help to lessen these difficulties.

Commenter 17757 notes that the EPA analysis failed to take into account the impact of each of the CSAPR and the proposed EGU air toxics rule on the common objective of appropriate and reasonable emissions control.

Commenter 17842 states that while the rule estimates costs of compliance and anticipated retirements, it is the collective impact of all emission regulations affecting EGUs that the industry fears will create a snowballing cost effect, ultimately taking utilities to a point where they would have been better off investing in other base load generation sources. The commenter believes the proposed Utility MACT rule does not account for these concerns, and the resulting uncertainty places utilities in a very disagreeable position in terms of generation planning.

Commenter 17917 states that the EPA should consider the cumulative effects of the host of proposed and recently final rules, including these proposed rules, to the power utility and manufacturing sectors, not to mention ratepayers and others affected. The commenter believes these rules neither promote economic growth, competitiveness nor job creation.

Commenter 17919 states the EPA should address the timeframe and content of overlapping rules for the power sector, beginning with Utility MACT. The commenter believes rules should impose the "least burden," taking into account the multiple and overlapping rules facing the power sector. Where the EPA has the capacity for flexibility, such as in the control of non-Hg HAP, subcategorization, determination of the MACT floor, and other areas, the commenter believes the EPA should do so. The commenter notes that numerous rules promulgated or expected to be promulgated in 2010-2012, in conjunction with Utility MACT, means that the generating units subject to these rules would either have to undertake the installation of extensive retrofits on an unrealistic timeframe or else shutdown entirely. The commenter suggests that the EPA extend the compliance period in the proposed rule to allow for such retrofits.

Commenters 17806 and 17833 state that the proposed rule, in addition to the NSPS for GHG emissions, new regulations for handling coal ash, and new revisions to the ozone and PM NAAQS, will have a negative impact on the economies of many regions. Commenters add that the EPA has not described how the regulations interrelate or whether they have a collective benefit. Commenter requests that the agency withdraw all the proposals mentioned and conduct a cumulative impact assessment.

Response to Comment 1: The Agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: 1) the various EO requirements that the Agency must comply with require us to estimate impacts specific to this rule; 2) decision makers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; 3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, EPA makes clear statements about what impacts, costs, and benefits will be generated as a result of this particular regulation.
This does not, however, mean EPA has failed to consider cumulative impacts of the regulation. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the broader cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed at the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html.

The direct benefits of the 1990 Clean Air Act Amendments and associated programs significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits exceed costs combined with extensive uncertainty analysis suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. This conclusion is likely to also be attributable to this rule as shown in the RIA.

In implementing rules such as the MATS, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the NAAQS for PM and ozone in some areas and assist other areas with attaining these NAAQS. Although both RIAs calculate PM and ozone costs and benefits, it is important to note that there are key differences in the design and analytical objectives of a NAAQS RIA and one for a rule such as MATS. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that states may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. Some costs and benefits estimated in the final MATS RIA account for the same air quality improvements as estimated in the illustrative $PM_{2.5}$ and ozone NAAQS RIA, but these effects are only counted once when considering cumulative costs and benefits.

Comment 2: Commenter 19042 suggests the EPA failed to follow the guidelines in EO 13563 for assessing the impact of the proposed regulation on federal agencies as well as state and local governments. The commenter cites OMB Circular A-4, suggesting that the EPA is required to consider as part of its RIAs, significant increases in the federal government's administrative costs. The commenter believes that if the EPA's Utility MACT standards result in higher electricity costs for itself and other federal agencies, thereby making it more difficult to administer government programs, such costs are considered administrative in nature.

Response to Comment 2: The EPA disagrees with the commenter's assertion that the agency failed to follow the guidelines in EO 13563 and OMB Circular A-4. Circular A-4 requires the analysis of government administrative costs or savings when those effects are expected to be significant. The EPA's analysis of costs does include direct costs to government-owned facilities that are subject to regulation under the rule. The agency does not believe that the indirect administrative costs are large enough to have a significant impact.

Comment 3: Commenters 17702 and 18018 believe the EPA has an obligation to maintain consistency in its regulations when addressing court vacaturs and remands of CAIR and CAMR. The commenters also state the EPA increased the stringency of both the Clean Air Transport Rule (CATR) and the proposed utility air toxic rule beyond what is necessary to address the deficiencies identified by the Courts.

Response to Comment 3: The EPA disagrees with the commenters' assertions concerning CAMR and notes that comments on CAIR are outside the scope of this action. The D.C. Circuit Court vacated, not remanded, CAMR because the Court determined that the EPA had not properly delisted EGUs from the section 112 list of sources and the EPA did not have the authority to regulate HAP emissions under section 111 for source categories listed under section 112. (*New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008).) The EPA is finalizing standards for EGUs under section 112(d) of the CAA and we maintain that our action is consistent with the D.C. Circuit Court's decision.

Comment 4: Commenter 17638 states that the EPA did not respond to a Congressional inquiry regarding statements that the EPA coordinated with DOE, FERC, the National Electric Reliability Council (NERC), Public Utility Commissions (PUCs), and Regional Transmission Organizations (RTOs).

Response to Comment 4: The EPA is separately working on those responses. Status of the EPA responses to Congressional inquiry does not affect the EPA's authority or responsibility under section 112 to issue final emission standards for EGUs.

Comment 5: Several commenters (17868, 17758, 17911, 18106) state the EPA has not proposed any of the regulatory options to reduce burdens and maintain flexibility in order to comply with the EO requirements to consider flexible approaches. Commenter 17911 notes the EPA failed to respond to the recommendation for less intrusive regulatory approaches suggested during the SBAR Panel process. Commenter 17758 states that many of the proposed measures for demonstrating compliance impose unnecessary burdens and excessive costs in contradiction to the EO. The commenter recommends these restrictive requirements be removed.

Response to Comment 5: The EPA believes it has appropriately incorporated provisions that provide regulated EGUs with the maximum flexibility permitted by the statute to reduce emissions and achieve compliance in the most cost-effective and efficient manner possible for the particular EGU, while assuring that significant reductions in emissions and the health benefits attendant to such reductions will be realized. Examples include: (1) the work practice standards for dioxin/furans and non-dioxin/furan organic HAP, (2) the EPA's treatment of variability in setting emission standards, (3) the provisions allowing emissions averaging to demonstrate compliance, (4) the availability of surrogates to determine compliance, (5) the choice for existing sources to comply with either input-based or output-based emission limitations, (6) the statutory eligibility for a 1-year extension to comply with the rule in the event that the additional time is necessary for installation of controls, consistent with the statutory requirements of section 112(i)(3), and (7) the provision of an affirmative defense to any malfunction.

Comment 6: Commenter 17751 states the EPA has not demonstrated that it has considered the relative costs of achieving the benefits associated with the proposed regulation affecting the EGU sector by means of alternative regulatory strategies.

Response to Comment 6: Although the proposed rule did not include a full quantitative analysis of a more and less stringent regulatory alternative, a quantitative analysis of costs was included in the MACT Floor TSD to illustrate the feasibility of the beyond-the-floor standard for lignite. The analysis of the floor for all subcategories constitutes a less stringent alternative than the proposed standard. Additionally, the proposal includes a qualitative discussion of a number of alternative approaches such as a health-based standard and alternative subcategorization.

Comment 7: Commenter 17721 suggests that the proposed rule would negatively impact innovation if ACI technology remains the only EPA-endorsed Hg control technology. The commenter suggests that the proposed rule include a variety of Hg control systems, including DLPS technology.

Response to Comment 7: The commenter is incorrect – the EPA does not endorse any specific type of pollution control technology, nor does it mandate or prohibit technologies. The MACT standard is an emission-based standard that is established by considering the maximum emission reductions currently achieved by existing EGUs. Individual facilities are free to use whatever technology they wish in order to achieve this standard. Contrary to the commenter's belief, the MACT standard encourages innovation by spurring companies to develop more effective and efficient methods for achieving the necessary emission reductions.

Comment 8: Commenter 17681 states that the EPA must explain how the proposed rule utilizes the best techniques to accurately quantify present and future benefits. Commenter 17681 states that the EPA must explain how the proposed rule ensures the objectivity of scientific and technological information and processes to support the action.

Response to Comment 8: The EPA recognizes its obligations under EO 13563 to use the best available techniques to accurately quantify both present and future costs and benefits as well as to ensure the objectivity of scientific and technological information and processes used in its analysis. As such, the EPA relies upon guidance from its independent scientific and economic review panels and employs peer reviewed processes and technical literature in completing its analyses. All necessary documentation is provided in the RIA and technical support materials accompanying the final rule.

Comment 9: Commenter 17868 acknowledges that the EPA has discretion in developing utility air toxics under section 112, and that EO 13653 provides important guidance as to use of this discretion. The commenter believes the projected cost for the rule is significant while providing only minimal benefits from the direct reduction of HAP. The commenter notes that 99.99% of the benefits from the proposed rule will result from co-benefits associated with estimated reductions of SO_2 and NO_X, resulting in lower ambient $PM_{2.5}$ and ozone levels; however, these co-benefits are expected to occur following the implementation of other CAA requirements in progress.

Response to Comment 9: The EPA disagrees with the commenter's assertion that the benefits achieved from this rule are expected to occur from the implementation of other CAA requirements. In implementing rules such as the MATS, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the NAAQS for PM and ozone in some areas and assist other areas with attaining these NAAQS. Although both RIAs calculate PM and ozone costs and benefits, it is important to note that there are key differences in the design and analytical objectives of a NAAQS RIA and one for a rule such as MATS. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. Some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in the illustrative $PM_{2.5}$ and ozone NAAQS RIA, but these effects are only counted once when considering cumulative costs and benefits. The EPA believes that to properly understand the impacts of this rule, it is equally important to identify the co-benefits from reductions in PM and ozone as it is to identify the direct benefits resulting from reductions in HAP.

Comment 10: Commenter 17638 believes the EPA has not provided sufficient time for the public to meaningfully participate in this rulemaking, and the EPA's adherence to the November finalization date precludes the EPA from meaningfully understanding and responding to comments that will be provided. The commenter believes if the EPA does not appropriately change this schedule, the EPA's actions are (and will be) arbitrary and capricious, and a violation of the Administrative Procedure Act. At a minimum, the commenter suggest the EPA must explain how its actions are consistent ·with the '''General Principles" and "Public Participation" directives of EO 13563.

Response to Comment 10: The EPA is mindful both of its obligation to provide an opportunity for public comment and of its obligation to proceed with this rule in a timely manner, but disagrees with the commenter's assertion that it has acted arbitrarily or capriciously with regard to these obligations. The agency is obligated to finalize the MATS by December 16, 2011, consistent with a consent decree. This date reflects a 30-day extension the EPA obtained from the original November 16, 2011 deadline. The proposed rule was signed on March 16, 2011 and the public comment period was scheduled to close on July 5, 2011. The EPA extended the comment period an additional 30 days to close August 4, 2011. Agency staff began reviewing comments and identifying key issues prior to the close of the comment period. Additionally, the EPA held three public information sessions in Chicago, Atlanta and Philadelphia during the month of May where the public was able to provide comment on the rule. The EPA believes that its approach to public comments meets or exceeds both the letter and spirit of the EO's guidance on public participation.

Comment 11: Commenter 17702 believes the EPA increased the stringency of the proposed rule without regard to the lack of additional health benefits that might accrue or additional costs that will be incurred by the public. The commenter instead states that the EPA should use its discretion to minimize the cost of the rule while still providing for safety of the public.

Response to Comment 11: The EPA disagrees with the commenter and notes that under the CAA, the agency has limited discretion in setting a MACT floor standard. The MACT floor standard is a technology-based standard based on the performance of existing sources in the regulated source category. It provides the minimum level of HAP emission control required for new and existing sources. The MACT floor for new sources is equivalent to the level of HAP emission control achieved by the best-controlled similar source, and the MACT floor for existing sources is the average level of HAP emission control achieved by the top 12% of sources each category or subcategory with 30 or more sources and the best performing 5 sources for each category or subcategory with less than 30 sources. Based on the requirements of the CAA, the EPA can only consider economic, environmental, and health impacts when setting a standard more stringent than the MACT floor. Although the EPA explored several alternatives for standards beyond the MACT floor, ultimately, only the low rank virgin coal subcategory was subject to a more stringent standard.

2. The EPA did comply with EO 13563.

Comment 12: Commenter 17648 states that the proposed rule complies with EO 13563 by producing benefits that far exceed its costs and promoting economic and job growth. The commenter believes the EPA also complied with the other requirements of the EO by involving the public, employing where it can flexible approaches such as averaging, establishing performance based standards, relying on sound objective science, requiring coordination and harmonization of regulatory actions and the promotion of innovation.

Response to Comment 12: The EPA thanks the commenter for these observations.

3. Legal considerations and EO 12866 and 13563.

Comment 13: Commenter 17768 believes the EPA has the legal authority to reinterpret "appropriate" to allow for the consideration of costs and benefits, as well as the statutory authority to consider net benefits under section 112(d), and should do so to best adhere to the principles of EO 12866 and 13653, which instruct agencies to maximize net benefits unless a statute requires another regulatory approach.

Comment 14: Commenter 17842 encourages the EPA to consider the overall objective of section 112(n) to reduce Hg emissions while considering the call of EO 13563 to "propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs."

Response to Comments 13 - 14: The Executive Orders supplement but cannot modify or diminish statutory requirements. The EPA believes the agency's interpretations of section 112(n)(1) and 112(d) constitute reasonable interpretations of the statute. While we agree that the cited executive orders direct the EPA to maximize benefits and minimize costs to regulated industries, we believe that we have done so within the constraints imposed by the CAA.

7B - Paperwork Reduction Act

No comments were received specifically on the Paperwork Reduction Act (PRA) requirements, although the PRA is mentioned in the context of some comments regarding another topic and have been addressed as appropriate.

7C - Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA)

Commenters: 10987, 16705, 17004, 17400, 17608, 17648, 17689, 17712, 17805, 17817, 17868, 17885, 17911, 18032, 19094, 19121, 8443

1. General.

Comment 1: Commenters 16705 and 17400 express concern that smaller utilities and those in rural areas will be unable to get vendors to respond to their requests for proposals, since they will be able to make more money serving larger utilities.

Response to Comment 1: The preamble to the proposed rule (76FR 25054, May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed rule. The EPA has provided pursuant to section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. CAA section 112(i)(3)(B). If the situation described by commenters (i.e., where smaller utilities and those in rural areas are less able to get vendor responses to requests for proposals than larger utilities) results in the source needing additional time to install controls, they would be in a position to request the 1-year extension.

2. Concerns with SBAR Panel.

Comment 2: Multiple commenters (8443, 10987, 17689, 17712, 17817, 17885, 17868) believe Small Entity Representatives (SERs) were not provided with regulatory alternatives including descriptions of significant regulatory options, differing timetables, or simplifications of compliance and reporting requirements, and subsequently presented with an opportunity to respond. Commenters reference the Report of the SBAR Panel, citing the following text: "SERs stated that they do not believe they were provided the opportunity for effective participation in the Federal regulatory process as required by SBREFA."

Comment 3: Commenter 17608 believes the EPA's formal SBAR Panel notification and subsequent information provided by the EPA to the panel did not include information on the potential impacts of the rule as required by section 609(b)(1). The commenter states that such information was not provided until the EPA's submission to OMB/OIRA under EO 12866, after consultation with the SERs was complete.

Comment 4: Several commenters (8443, 17608, 17868) suggest that the EPA's rulemaking schedule put pressure on the SBAR Panel through the abbreviated preparation for the panel. Commenters 8443 and 17868 note that only one panel meeting was provided and after that meeting, Panel members were given a mere 14 days to prepare written comments on an incredibly complex topic. Commenters note that the lack of a pre-panel consultation resulted in the lack of SER involvement with the EPA to draft outreach materials and participate meaningfully.

Comment 5: Commenters 17608 and 17868 state that the EPA did not identify regulatory alternatives for the SBAR Panel to consider. The commenters state the EPA did not present a proposed regulatory approach with sufficient detail for SERs to identify potential economic effects of suggest specific regulatory alternatives; it had only presented them with broad discussions and raw data upon which the EPA would eventually make discretionary judgments. Commenters do not believe that the EPA's response to the SBAR Panel concerns regarding the deficiencies in the process relieves the EPA of its obligations under section 609(b).

Comment 6: Several commenters (8443, 17608, 17911) express concerns that the EPA did not provide participants more than cursory background information on which to base their comments. Commenter 17608 states that the EPA did not provide deliberative materials, including draft proposed rules or discussions of regulatory alternatives, to the SBAR Panel members. The commenter believes such materials could have guided the Panel's deliberations towards regulatory alternatives that minimize the burden on small entities.

Comment 7: Commenter 17608 states the SBAR Panel Report does not meet the statutory obligation to recommend less burdensome alternatives. The commenter suggests the EPA Panel members declined to make recommendations that went further than consideration or investigation of broad regulatory alternatives, with the exception of those recommendations in which the EPA rejected alternative interpretations of the CAA section 112 and relevant court cases. The commenter does not believe the Panel was provided with information necessary to make recommendations beyond a restatement of the EPA's existing obligations or to evaluate specific regulatory decisions and the impacts of those decisions on particular small entities or small entities in general.

Comment 8: Commenters 17868 and 17911 note that the EPA did not respond to the concerns of the small business community, the Small Business Administration (SBA), or OMB, ignoring concerns expressed by the SER panelists. Commenter 17868 notes specifically that the EPA did not respond regarding the 3-year compliance deadline and by not acting upon OMB's suggestions to meet again before the rule was proposed.

Comment 9: Commenter 19121 believes the EPA failed to convene required meetings and hearings with affected parties as required by law for small business entities.

Comment 10: Commenter 8443 notes that public power accounts for about 16% of all kW-hr sales to retail electricity consumers, approximately 46% of the MW-hr of electricity produced by public power systems are generated using coal, and more than 90% of public power utility systems meet the definition and qualify as small businesses under the SBREFA, giving more importance to the Panel.

Response to Comments 2 - 10: The RFA requires that panels collect advice and recommendations **from** SERs on the issues related to:

- the number and description of the small entities to which the proposed rule will apply;

- the projected reporting, record keeping and other compliance requirements of the proposed rule;

- duplication, overlap or conflict between the proposed rule and other federal rules; and

- alternatives to the proposed rule that accomplish the stated statutory objectives and minimize any significant economic impact on small entities.

The RFA does not require a covered agency to create or assemble information for SERs or for the government panel members. Although section 609(b)(4) requires that the government panel members review any material the covered agency has prepared in connection with the RFA, the law does not prescribe the materials to be reviewed. The EPA's policy, as reflected in its RFA guidance, is to provide as much information as possible, given time and resource constraints, to enable an informed panel discussion. In this rulemaking, because of a court-ordered deadline, the EPA was unable to hold a pre-panel meeting but still provided SERs with the information available at the time, held a standard Panel Outreach meeting to collect verbal advice and recommendations from SERs, and provided the standard 14-day written comment period to SERs. The EPA received substantial input from the SERs, and the Panel report describes recommendations made by the Panel on measures the Administrator should consider that would minimize the economic impact of the proposed rule on small entities. The EPA believes it has properly complied with-the RFA.

3. Impacts on small businesses.

Comment 11: Commenter 17004 requests that the EPA work with utilities such that new regulations are as flexible and cost efficient as possible.

Response to Comment 11: In developing the final rule, the EPA has considered all information provided prior to, as well as in response to, the proposed rule. The EPA has endeavored to make the final regulations flexible and cost efficient while adhering to the requirements of the CAA.

Comment 12: Commenter 17868 is concerned about the ability of small entities or nonprofit utilities such as those owned and/or operated by rural electric co-op utilities, and municipal utilities to comply with the proposed standards within 3 years. The commenter believes that the EPA disregarded the SER panelists who explained that under these current economic conditions they have constraints on their ability to raise capital for the construction of control projects and to acquire the necessary resources in order to meet a 3-year compliance deadline.

Response to Comment 12: The preamble to the proposed rule (76 FR 25054, May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed rule. The EPA has provided pursuant to section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. CAA section 112(i)(3)(B). If the situation described by commenters (i.e., where small entities or nonprofit utilities constraints on ability to raise capital for construction of control projects and to acquire necessary resources) results in the source needing additional time to install controls, they would be in a position to request the 1-year extension.

Comment 13: Commenters 17868 and 18032 believe the EPA did not adequately consider the disproportionately large impact on smaller generating units. The commenters note the diseconomies in scale for pollution controls for such units. Commenter 17868 notes the rule will create a more serious compliance hurdle for small communities that depend on coal-fired generation to meet their base load demand. The commenter notes that by not subcategorizing units, the EPA is dictating a fuel switch due to the disproportionately high cost on small communities.

Commenter 18032 believes the MACT and NSPS standards are unachievable by going too far without really considering the impacts on small municipal units, as public powers is critical to communities, jobs, economic viability and electric reliability.

Commenter 17868 believes that the EPA has not fully recognized the number of small entities that are impacted by the rule and underestimated the impacts of the proposed rule on smaller utilities despite the SER panel.

Comment 14: Commenter 19094 is a generating and transmissions electric cooperative which qualifies as a small entity and believes the proposed rule will ultimately result in increased electricity costs to its members and will negatively impact the economies of the primarily rural areas that they serve.

Comment 15: Commenter 17648 believes there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units, particularly given the current market situation and applicable equitable factors. The commenter suggests both the EPA's and SBA's analyses focus exclusively on the effects on entities causing HAP emissions and primarily on those operating obsolete EGUs, and fail to consider either impacts on downwind businesses and governments or the positive impacts on small entities and governments owning and operating competing, clean and modern EGUs.

Response to Comments 13 - 15: The EPA disagrees with the commenters' belief that the impacts on smaller generating units were not adequately considered when developing the proposed rule. The EPA determined the number of potentially impacted small entities and assessed the potential impact of the proposed action on small entities, including municipal units. A similar assessment was conducted in support of the final action. Specifically, the EPA estimated the incremental net annualized compliance cost, which is a function of the change in capital and operating costs, fuel costs, and change in revenue. The projected compliance cost was considered relative to the projected revenue from generation. Thus, the EPA's analysis accounts not only for the additional costs these entities face resulting from compliance, but also the impact of higher electricity prices. The EPA evaluated suggestions from SERs, including subcategorization recommendations. In the preamble to the proposed rule, the EPA explains that any basis for subcategorizing should be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not see a distinction between emissions from smaller generating units versus larger units. One commenter (17648) believes that there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units. The commenter points out that relaxation in standards would not only harm downwind governments and small businesses who incur higher labor costs due to pollution, but will harm other small businesses and state, tribal and local governments developing or operating generation facilities using modern and less polluting generation technologies. The EPA acknowledges and generally agrees with the commenter's assertion.

Comment 16: Commenter 18032 notes that the EPA recognizes LEEs in the rule such that they should receive less onerous monitoring requirements; however, the EPA does not recognize that small and LEEs also need and merit more flexible and achievable pollution control requirements. The commenter notes that the capital costs for emissions control at small-sized utility units is disproportionately high due to inefficiencies in Hg removal, space constraints for control technology retrofits, and the fact that small units have fewer rate base customers upon which to spread these costs. The commenter cites the Michigan Department of Environmental Quality report titled "Michigan's Mercury Electric Utility Workgroup, Final Report on Mercury Emissions from Coal-Fired Power Plants," (June 2005). The commenter notes that the EPA has addressed such concerns previously, citing the RIA for the 1997 8-hour ozone standard. The commenter also suggests smaller utility systems generally have less capital to invest in pollution control than larger, investor-owned systems, due to statutory inability to borrow from the private capital markets, statutory debt ceilings, limited bonding capacity, borrowing limitations related to fiscal strain posed by other, non-environmental factors, and other limitations.

Response to Comment 16: The EPA acknowledges its proposal of reduced monitoring requirements for existing units that qualify as low emitting EGUs. Although the EPA does not believe that reduced pollution control requirements are warranted for LEEs, including small entity LEEs, we believe that flexible and achievable pollution control requirements are promoted through alternative standards, alternative compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs.

Comment 17: Commenter 8443 believes that the EPA should develop more limited monitoring requirements for small EGUs. The commenter notes small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as Hg CEMS and PM CEMs. The commenter notes the EPA could have identified monitoring alternatives to the SBAR panel for consideration.

Response to Comment 17: The EPA provided monitoring alternatives to using PM CEMS, HCl CEMS, and Hg CEMS in its standards. The continuous compliance alternatives would be available to all affected sources, including small entities. As monitoring alternatives to use of PM CEMS and HCl CEMS, sources would be allowed to conduct additional performance testing. Sorbent trap monitoring would be allowed in lieu of Hg CEMS.

4. The EPA did not comply with the RFA.

Comment 18: Commenter 17608 believes the EPA has not sufficiently complied with the requirements of the RFA or adequately considered the impact this rulemaking would have on small entities. The commenter believes the EPA has not given itself the opportunity to engage in meaningful outreach and consultation with small entities and therefore recommends that the EPA seek to revise the court-agreed deadlines to which this rulemaking is subject, re-convene the SBAR panel, prepare a new initial regulatory flexibility analysis (IRFA), and issue it for additional public comment prior to final rulemaking.

Commenter 17608 believes the IRFA does not sufficiently consider impacts on small entities as identified in the SBAR Panel Report. The commenter believes it is not apparent that the EPA considered the recommendations of the Panel. The commenter believes the description of significant alternatives in the IRFA is almost entirely quoted from the SBAR Panel Report, which the commenter does not believe is an adequate substitute for the EPA's own analysis of alternatives. The commenter also notes the EPA does not discuss the potential impacts of its decisions on small entities or the impacts of possible flexibilities. Where the EPA does consider regulatory alternatives in principle, the commenter believes it does not provide sufficient support for its decisions to understand on what basis the EPA rejected alternatives that may or may not have reduced burden on small entities while meeting the stated objectives of the rule. Additionally, the commenter notes that the EPA did not evaluate the economic or environmental impacts of significant alternatives to the proposed rule.

Commenter 17608 believes that the EPA's stated reasons for declining to specify or analyze an area source standard are inadequate under the RFA. The commenter believes the EPA must give serious consideration to regulatory alternatives that accomplish the stated objectives of the CAA while minimizing any significant economic impacts on small entities and that the EPA has a duty to specify and analyze this option or to more clearly state its policy reasons for excluding serious consideration of a separate standard for area sources.

Commenter 17608 suggests that the EPA reconvene the SBAR Panel to solicit more meaningful consultation with the SERs; the EPA prepare an IRFA that includes descriptions of specific regulatory alternatives, the effects on small entities of the regulatory alternatives, and the policy reasons for selected among them; and the EPA release the IRFA for additional public comment before making any decisions about the EPA's preferred options for final rulemaking. The commenter recognizes that the EPA will have to request of the litigants and the court an extension of the timeline for final rulemaking but feels strongly that this action is necessary.

Comment 19: Commenter 17805 believes the EPA did not fully consider the subcategorization of sources such as boilers designed to burn lignite coals versus other fossil fuels, especially in regard to non-Hg metal and acid gas emissions. The commenter references the SBAR Panel Report suggestion provided in the preamble of the proposed rule that the EPA consider developing an area source versus major source distinction for the source category and the EPA's response.

Comment 20: Commenter 17868 is concerned that the recommendations made by the SER participants were ignored and not discussed in the rulemaking. Specifically, the commenter notes the EPA did not discuss subcategorizing by age, type of plant, fuel, physical space constraints or useful anticipated life of the plant. Nor did the EPA provide any opportunity for smaller emitters to use GACT—often used in other EPA MACT regulations to alleviate the regulatory costs and operational difficulties that would have burdened other small businesses including dry cleaners, metal fabricating, metal finishing, and others.

Comment 21: Commenter 17817 believes it is likely that different numerical or work practice standards are appropriate for area sources of HAP, just as in other rulemakings such as the RICE rule, and that the EPA would have provided the opportunity for small entities to make such demonstration had they followed their own regulatory requirements.

Response to Comments 18 - 21: The EPA disagrees with one commenter's (17608) assertion that the agency has not complied with the requirements of the RFA. The EPA complied with both the letter and spirit of the RFA, even under the court-ordered deadline. For example, the EPA notified the Chief Counsel for Advocacy of the SBA of its intent to convene a Panel; compiled a list of SERs for the Panel to consult with; and convened the Panel. The Panel met with SERs to collect their advice and recommendations; reviewed the EPA materials; and drafted a report of Panel findings. The EPA further disagrees with the commenter's assertion that the EPA's IRFA does not sufficiently consider impacts on small entities. The EPA's IRFA, which is included in chapter 10 of the RIA for the proposed rule, describes, among other things, the economic impact of the proposed rule on small entities and the Panel's findings. The economic impact of the final rule on small entities is included in chapter 7 of the RIA for the final rule.

Several commenters (17608, 17805, 17868, and 17817) are concerned that recommendations made by the SERs were ignored and not considered or discussed in the proposed rulemaking. Specifically, commenters cite SER recommendations regarding subcategorization and separate standards for area sources. The EPA disagrees with the commenters. The preamble to the proposed standards includes detailed discussion of how the EPA determined which subcategories and sources would be regulated (76 FR 25036-25037, May 3, 2011). In that discussion, the EPA explains the rationale for its proposed subcategories based on five unit design types. In addition, the EPA acknowledges the subcategorization suggestions from the SERs and explains its reasons for not subcategorizing on those bases. The preamble to the proposed standards also includes a discussion of the SERs' suggestion that area source EGUs be distinguished from major-source EGUs and the EPA's reasons for not making that distinction (76 FR 25020-25021, May 3, 2011).

One commenter (17608) suggests that the EPA pursue an extension of the timeline for final rulemaking such that the SBAR Panel can be reconvened and a new IRFA can be prepared and released for public comment prior to the final rulemaking. The EPA entered into a Consent Decree to resolve litigation alleging that the EPA failed to perform a non-discretionary duty to promulgate CAA section 112(d) standards for EGUs. *American Nurses Ass'n v. EPA*, 08-2198 (D.D.C.). That Consent Decree initially required the EPA to sign the final MATS rule by November 16, 2011, but the EPA negotiated a 30-day extension of the deadline with the plaintiffs in the litigation consistent with the requirements of the modification provision of the Consent Decree. If plaintiffs in the *American Nurses* litigation objected to an additional extension request, which we believe they would, the agency would have had to file a motion with the Court seeking an extension of the deadline. Consistent with governing case law, the agency would have been required to demonstrate in its motion for extension that it was impossible to finalize the rule by the deadline provided in the Consent Decree. *See Sierra Club v. Jackson*, Civil Action No. 01-1537 (D.D.C.) (Opinion of the Court denying EPA's motion to extend a consent decree deadline). The EPA was able to complete the rule by December 16, 2011; accordingly, the agency had no basis for seeking a further extension of time.

7D - Unfunded Mandates Reform Act of 1995

Commenters: 16859, 17868, 17911, 18023

Comment 1: Commenter 16859 believes the EPA in its proposed rule does not appear to have addressed the statement in UMRA section 202(a)(2) directing federal agencies to consider direct state administrative costs and to make this information available to the public. The commenter cites concerns that state, local and tribal government officials expressed at a meeting with the EPA in October 2010 regarding the potential burden associated with implementing the rule, noting that the EPA did not respond to these concerns in the proposed rulemaking.

Response to Comment 1: UMRA focuses on mandated costs associated with enforceable duties falling on states. State administrative costs are not expressly included in UMRA as the type of costs to be included in analyzing cost impacts to the states. Thus, the EPA does not interpret state administrative costs to be among mandated costs, and state administrative costs were not addressed in the proposed rule and also are not addressed in the final rule. The UMRA discussion in the preamble to the final rule addresses this response to the commenter's concern.

Comment 2: Commenter 17868 suggests the EPA failed to meet the requirements of UMRA as the proposed rule does not consider significant impacts on small municipalities. These impacts include the increased cost of power being driven up by the compliance costs of the proposed rule, and the social and economic impacts of the potential shut down of power plants on municipal governments. The commenter was unable to find information in the rulemaking record regarding the qualitative and quantitative assessment of the anticipated costs and benefits of the proposed regulation on local governments, or an assessment of the disproportionate effect of the rule on regions of the country.

Further, commenter 17868 notes that additional regulatory permitting costs would be incurred by public power utilities, and therefore any comments submitted by municipal or state governments, including their electric utilities, be considered under SBREFA and UMRA. The commenter notes that the adverse cost impacts from the EGU MACT would extend directly to municipal and local government operating budgets, and that increasing operating costs for such not-for profit power producers would be passed on directly to rate payers. The commenter also notes that significant increased costs may reduce Payments in Lieu of Taxes to municipal operating budgets, which could in turn result in cuts to essential governmental services including emergency services and schools.

Comment 3: Commenter 17911 believes the EPA failed to provide a complete financial analysis of the cost to communities in the proposed rule. The commenter identifies specific items which the EPA did not take into account: (1) The impact of the rule on the Payment in Lieu of Taxes received by the community from the local municipal utility; (2) The additional costs to be borne by city government in paying for the electricity that they use for powering city government; (3) The additional costs to borne by the city through the utility for increases in default rates on utility payments; (4) The cost to the city budget of potential downgrade to municipal bond ratings caused by the city having to take on higher debt load to pay for the emission upgrades; (5) The disparate impact of the rule on smaller cities and smaller generating units; and (6) The social and economic impact of the shutdown of municipal power generation in smaller towns and the resulting increase in power costs on the competitiveness of local industries and other major employers.

Response to Comments 2 - 3: The EPA assessed the impact of the proposed and final rule on all directly-impacted municipalities (those holding covered EGUs). As required by UMRA, the EPA provided a written statement of the qualitative and quantitative impacts to state, local, and tribal governments, and the private sector. This analysis is presented for all municipalities in section 10.2 of the RIA for the proposed rule and Chapter 7 of the RIA for the final rule, and specifically for small municipalities in section 10.1 of the RIA for the proposed rule and section 7.5 of the RIA for the final rule. Total compliance costs for all government and private sector entities are presented in Chapter 8 of the proposal RIA and Chapter 3 of the final RIA. In the EPA's analysis, a "small" government jurisdiction is defined as the government of a city, county, town, district, or special district with a population of less than 50,000. The EPA estimated the incremental net annualized compliance cost, which is a function of the change in capital and operating costs, fuel costs, and change in revenue. The projected compliance cost was considered relative to the projected revenue from generation. Thus, the EPA's analysis accounts not only for the additional costs these entities face resulting from compliance with the proposal, but also the impact of higher electricity prices that government entities should face, and does account for projected early retirements due to the proposal among affected units owned by government entities. All of these results are included in Chapter 10 of the RIA for the proposed rule and Chapter 7 of the RIA for the final rule, and detailed results are found in the docket for the rulemaking.

As previously stated, the EPA's analysis of costs includes direct compliance costs to units owned by states or municipalities that are subject to regulation under the rule. The EPA does not believe that indirect administrative costs are large enough to have a significant impact. Additionally, while local governments may incur administrative costs as outlined by the commenter, such costs would be nearly impossible to estimate with any degree of accuracy due to the unique characteristics of each affected community and the numerous approaches local governments could take to minimize or offset administrative costs of the rule.

Comment 4: Commenters 17868 and 17911 express concerns over an apparent lack of communication from the EPA regarding potential impacts of the proposed rule with state and local governments as required by UMRA. The commenters discuss these shortcomings with respect to the EPA meeting with the "Big Ten" on October 7, 2010. Specifically, the commenters submit that the "Big 10" organizations are unlikely to have stakeholders that will be impacted by the MACT rule, and the commenters are not aware that any of the state/local governments that the EPA estimates will be impacted by the MACT rule received any meaningful communications regarding potential impacts."

Response to Comment 4: The EPA disagrees with the commenters that there was a lack of communication between the EPA and state and local governments regarding potential impacts of the proposed rule. Although details of the proposed rule had not been established at the time of the October 2010 meeting, the EPA believes that meaningful information was shared with representatives of the state and local organizations early in the regulatory process. The presentation that the EPA used to overview the Utility MACT regulatory effort at the October 2010 meeting with the "Big 10" included information indicating that the EPA was early in the process of developing the proposed action. Specifically, the presentation included a list of central decision points and potential issues (e.g., MACT floors and variability, subcategorization, pollutants for which standards would be established) for which decisions had not yet been made and the EPA was seeking input. That presentation is available in the rulemaking docket. As pointed out above, even though specific information regarding costs and other consequences of regulatory alternatives was not available, decisions and issues that would affect costs and other consequences of regulatory alternatives were presented for discussion at the October 2010 meeting with the "Big 10." Thus, this process enabled meaningful and timely input by state and local officials.

The EPA also disagrees with the commenters that the "Big 10" organizations are unlikely to have stakeholders potentially impacted by the MACT rule. As examples, The National Association of Towns and Townships represent smaller communities, towns and townships, and other suburban and rural localities; the National Association of Counties represents county governments; and the National League of Cities serves as a resource to and an advocate for the more than 19,000 cities, villages and towns. In fact, 48 of the 112 state/local governments the EPA estimated to be potentially impacted by the MACT rule are also small government entities. Further, ten SERs were representatives of small entity representatives that participated in the SBAR panel process for the proposed rule. Thus, the EPA disagrees that potentially impacted state/local governments did not receive meaningful communications regarding potential impacts either directly or through representation in the Federalism consultation and/or the SBAR panel process.

Comment 5: Commenter 17911 notes that the EPA never responded to suggestions by SERs during December 2010 that the 3-year timeline proposed by the EPA was both unrealistic and impossible to meet.

Response to Comment 5: The preamble to the proposed rule (76 FR 25054, May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed rule. With respect to the final rule, the EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. CAA section 112(i)(3)(B).

Comment 6: Commenter 17911 states the EPA failed to fully evaluate the unintended consequences of this rule on local economies, especially in mid-sized and smaller communities where a disproportionate share of those over 65 and those under the poverty level reside.

Response to Comment 6: The EPA conducted its economic analyses in response to the statutory and executive orders requirements that it must follow for economically significant rules such as this one. The agency's analysis included estimates of the increase in retail electricity price both nationally and regionally, and this analysis shows no increases in retail electricity price above 7% in 2015, and lower price increases thereafter. Such an analysis is informative to meet the requirements of EO 12898 (Environmental Justice). State and local authorities are best equipped to mitigate impacts related to increases in electricity rates.

Comment 7: Commenter 18023 states that the EPA's RIA must adhere to UMRA and EO 12866 in conducting cost-benefit analysis.

Response to Comment 7: The EPA adhered to the requirements of UMRA and EO 12866 in preparing the cost-benefit analysis that is presented in the RIA for the proposed and final rules. The agency presented its analysis of the impact of the rule on federal, state, and local government entities in Chapter 10 of the RIA for the proposed rule and Chapter 7 of the RIA for the final rule. This analysis serves as the written statement that is required under section 202 of the UMRA. Intergovernmental consultations as required under section 204 were conducted and were placed in the docket for this rulemaking. The agency explained why this standard was proposed, and alternatives to it, in the preamble for the proposal. The contents of the RIA are consistent with what EO 12866, and the guidance in OMB Circular A-4, requires for an RIA.

7E - Executive Order 13132, Federalism

Commenters: 16859, 17701, 17791, 17868, 18447

1. Federalism requirements.

Comment 1: Commenter 16859 points out that section 6.(b)(2)(B) of EO 13132 requires that the EPA provide to the OMB a federalism summary impact statement (FSIS) containing a number of elements, including a statement of the extent to which the concerns of state and local officials have been met. Commenter indicates that states continue to remain uncertain of the extent to which the EPA is considering state administrative costs, including state administrative costs for this proposed utility MACT rule.

Response to Comment 1: As required by section 6(b)(2)(B) of EO 13132, the EPA provided a FSIS in its proposed rule and provides an updated impact statement in the preamble to the final rule. The final rule impact statement presents the EPA's assessment of the compliance costs of the regulatory option being promulgated on state and local governments. In addition, the statement addresses state and local officials' uncertainty regarding the extent to which the EPA is considering state administrative costs. We note that state administrative costs are not expressly included in the Federalism guidance as the type of costs to be included in analyzing cost impacts to the states. That is, the focus is on mandated costs associated with enforceable duties falling on states, and the EPA does not interpret state administrative costs to be among mandated costs.

Comment 2: Commenter 17868 believes that the EPA ignored several principal tenants of EO 13132. Specifically, the commenter references section 3(b) of EO 13132, which requires agencies to consult with state and local officials to determine whether federal objectives can be attained by other means where there are significant uncertainties as to whether national action is authorized or appropriate.

Response to Comment 2: Commenter implies that there is significant uncertainty about the agency's authority to issue the final rule and whether it is appropriate to address the hazards to public health and the environment posed by EGUs. The EPA disagrees with the commenter. The EPA determined that it was appropriate and necessary to regulate EGUs in December 2000 and added such units to the section 112(c) list. Sources listed must be regulated pursuant to section 112(d). See section 112(c)(2).

Comment 3: Commenter 18447 does not understand why the EPA categorically states that the federal government will not provide funds necessary to pay the imposed "substantial direct compliance costs on state and local governments." The commenter believes the costs of complying with the rule will be substantial and will impact ratepayers dramatically, potentially driving residents and businesses from the city in an effort to seek cheaper electricity elsewhere. The commenter believes its city is more disproportionately impacted by the rule than utilities with larger and more diverse generation resources.

Response to Comment 3: EO 13132 provides that when a regulation imposes substantial direct compliance costs, the agency has the option of either providing the funds necessary to pay those direct costs or consulting with state and local officials. It does not explicitly favor either option. With respect to the air toxics regulation for EGUs, the EPA consulted with state and local officials. As described in the preamble to the proposed rule, the EPA invited 10 national organizations representing state and local elected officials to a consultation meeting that was held on October 27, 2010 (76 FR 25085, May 3, 1011). The purposes of that consultation were to provide general background on the proposal, answer questions and solicit input from state/local governments. As required by the EO, a FSIS was included in the preamble to the proposed rule. An impact statement is also included in the preamble to the final rule.

In response to the commenter's concerns that their costs of complying with the rule will be substantial and disproportionately high resulting in dramatic impacts on their ratepayers, the EPA believes that flexible and achievable pollution control requirements are promoted through alternative standards, alternative monitoring and compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs. Moreover, as discussed elsewhere in this document, the EPA's analyses indicate that the impacts of compliance with the rule will not cause a significant increase in electricity costs to rate payers.

2. Federal and state interaction.

Comment 4: Commenters 17791 and 17701 appreciate the EPA's participation in ongoing meetings with industry, environmental groups, state air regulators and state energy officers to provide the opportunity to better understand how they can work together as rules such as this proposal are implemented. The commenters note that the EPA officials have made themselves available and have sought input on the rulemaking from their organization representing utility commissioners. The commenter encourages continued dialog and interaction between federal and state air and energy regulators.

Commenter 17791 points out that continued collaboration between the federal agencies, states, and industry will be essential to further promoting energy efficiency and reducing emissions. The commenter discusses prior state energy efficiency efforts that the EPA was involved with -- the National Action Plan on Energy Efficiency (NAPEE) and the State Energy Efficiency Action Network (SEE-Action).

Response to Comment 4: The EPA welcomes these observations and recognizes the important contributions of state and local governments to the rule development process. The EPA will continue to work with state and local governments to fulfill its mission of protecting human health and the environment.

7F - Executive Order 13175, Consultation and Coordination with Indian Tribal Governments

Commenters: 12462, 15182, 16122, 17674, 17732, 17733, 17846, 18017, 19686

Comment 1: Several commenters (12462, 16122, 17846) support stringent EPA regulations on toxic air emissions that must eliminate the disproportionate impact on the American Indians and Alaska Natives, and Indigenous Peoples, their lands, waters and natural resources.

Commenter 16122 also notes that the EPA has a responsibility to not only identify but address the very significant effects that Indian tribes and their members face from their exposure to Hg emissions from EGUs. The commenter notes the impacts of Hg contamination pose not only disproportionally high and adverse health effects, but unique and distinctive threat to its members because of the enormous and cultural value natural resources have for the Tribe and its members.

Comment 2: Commenter 15182 notes concern within tribal communities that methylmercury in *ogaa* (walleye) may pose a serious threat to the health of fetuses and young children as the practice of harvesting, sharing, and consuming the fish is passed down through generations. The commenter notes that *ogaa* and other fish represent a significant subsistence food source for tribal communities and that tribes are disproportionately impacted by the Hg levels in these fish that regularly exceed the EPA fish consumption guidance values. The commenter suggests that limitations on the consumption of *ogaa* and other species as a result of elevated Hg concentrations threaten the traditional Anisinaabe lifeway and the ability of the Chippewa people to fully exercise their treaty harvest rights.

Response to Comments 1 - 2: The EPA acknowledges the support for stringent federal regulations of EGU air toxics emissions from commenters and understands the concerns expressed by commenters with regard to tribal member exposure to Hg emissions from EGUs and elevated Hg levels in subsistence fish. We believe that the final rule will substantially reduce the emissions of Hg in the U.S. The resulting reduction in emissions will benefit communities with subsistence lifeways, including Native American Indians and Alaska Natives, whose traditional diets include high consumption of fish.

Comment 3: Commenter 12462 requests that the EPA fulfill its mandate to respect the rights of tribes, as sovereign governments, to exercise their right to self-determination with an appropriate consultation process on regulations that affect the health, safety and welfare of Indigenous Peoples. The commenter asserts that the federal government and the EPA must acknowledge its trust responsibility to Tribes to end the disproportionate impact of air toxins from EGUs. The commenter also cites an example in which the Michigan Department of Environmental Quality (MDEQ), was delegated the authority to issue a Permit to Install (PTI) to a coal-fired power plant but did not consider the different and disproportionate impacts on Tribes.

Comment 4: Several commenters (16122, 17733, 17846, 19868) state that the EPA has a strict duty and legal obligation under the Trust Responsibility to promulgate a MACT standard that fully and adequately protects its environmental interests and its tribal resources. Commenters note that it is clear that Hg deposition from EGUs have significantly impacted culturally-important lands, waters and natural resources on reservations.

Commenter 19686 recommends that the EPA devote more of its resources to conduct in-depth studies regarding the effects of Hg emissions on Tribal communities, and in fact, the EPA should do such studies for other pollutants. Further, commenter 19686 recommends that the EPA conduct a benefits analysis that fully assesses the rule’s impacts on Tribal air quality and health, as well as cultural and subsistence practices.

Comment 5: Commenter 18540 believes that the EPA has a trust responsibility to ensure that the Community's water rights, and other guarantees and benefits provided in the Arizona Water Settlements Act (AWSA) are preserved, and that the trust responsibility prohibits the agency from imposing a Utility MACT that limits the community's ability to receive and use Central Arizona Project (CAP) water. The commenter believes the proposed rule would force the closure of Navajo Generating Station (NGS), inhibiting and possibly eliminating the Community's right to receive and utilize its allocation of CAP water guaranteed by the AWSA. The commenter believes that the proposed Utility MACT rule would make it extremely difficult, if not impossible, to pay for CAP water and would eviscerate the future Development Fund revenue stream that is intended to subsidize CAP water costs and pay for operation, maintenance, and replacement charges associated with the delivery of CAP water. Even more, the proposed Utility MACT rule would limit the Community's ability to farm its reservation lands and its future economic development opportunities, and would negatively impact the livelihood and health of Community members.

Comment 6: Commenters 17674 and 17732 have concerns with the consultation with their tribal governments as required by EO 13175. Commenter 17674 is troubled that the EPA has not undertaken any formal consultation with their tribal community, despite a formal request submitted in July. The commenter believes given the nature of the interests at stake, the implications of the proposed rule, and the EPA's federal trust obligations, consultation must be among senior-level EPA officials and tribal leaders. Commenter 17732 states that the EPA only provided a generic letter to the tribal government as consultation. The commenter believes the proposed rule will have substantial direct effects on its tribal community, which relies on two of the three coal-fired power plants identified in the Tribal Outreach memo, and their supporting mines, for one third of its general operating fund in addition to significant jobs provided by both the plants and their mines. Therefore the commenter believes that the EPA must do better to engage their tribal government in meaningful consultation on this and other proposed rulemakings.

Response to Comments 3 - 6: The EPA appreciates these comments and recognizes the importance of appropriate consultation with tribes in developing this rule, consistent with the federal government's trust responsibility to federally recognized tribes. The EPA agrees that this rule affects tribes and as such, we actively encouraged tribes to participate in our rulemaking. We conducted outreach and information sharing with tribal environmental staff through the monthly National Tribal Air Association calls, at the National Tribal Forum, and a webinar targeting tribal environmental professionals on the content of the proposal. In addition, we sent letters to all tribal leaders and offered consultation on the rule, prior to proposal and after the proposal, to ensure tribes had the opportunity to participate in the process. Because of concerns raised by several tribes, and in order to help us better understand their concerns, we also participated in a face-to-face meeting with tribes in Arizona who were concerned about the potential impact of this rule on their income and water rights. Following that meeting, we held an additional technical meeting on how IPM is used in the RIA and provided one-on-one consultation with the Navajo Nation, Gila River Indian Community and the Ak-Chin Indian Community. Thus, the EPA disagrees with commenter statements that the EPA has not undertaken any formal consultation with their tribal community. The EPA also points out that senior-level EPA officials were involved in the meetings. The EPA would like to clarify that the generic letter to tribal governments to which one commenter refers was not intended to be "the consultation" but, rather, it offered consultation.

With regard to commenters' concerns about the impact of the final rule on NGS and the delivery of water under water settlements in Arizona, the EPA recognizes the significance of NGS to the Central Arizona Project and has been consulting with affected Indian tribes and working closely with other federal agencies, including the Department of the Interior, on these issues. The EPA does not believe that the agency is precluded from regulating NGS under section 112 of the CAA or that based on available information the water settlements require exclusion or disparate treatment of the facility under this CAA regulation. The facility is currently regulated under other CAA programs, and we believe that the requirements of section 112 also apply. The EPA is, however, mindful of the complex situation relating to NGS and the delivery of water in Arizona. The EPA is committed to continuing to work closely with affected tribes and other federal agencies to consider these issues as the rule is implemented, consistent with the federal government's trust responsibility to the tribes. The EPA also notes that it is not currently certain what decisions will be made with respect to NGS's operation to address the rule's requirements. The EPA's modeling and projections are intended to be a reflection of possible compliance using specific tools, assumptions, and methodologies that the agency believes to reflect the best and most current information related to the power sector. The inclusion of other regulatory actions (including federal, state, and local actions) in the modeling reflects the level of controls that are likely to be in place in response to other requirements apart from MATS and provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions. It is not intended to reflect actual compliance decisions, since those will be made individually by the affected industry based on what makes most sense using existing technologies or other, more cost-effective strategies. For that reason, we caution commenters not to assume that any statements in EPA's modeling analyses about possible actions by NGS, including closure, reflect the only possible outcome of the final rule. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues as they arise. Public utility commissions and other authorities, including tribes, will need to develop and implement compliance plans in order to address harmful emissions.

With regard to one commenter's concerns about the permits issued by the MDEQ, we note that the agency under its environmental justice (EJ) strategy known as Plan EJ 2014 is actively pursuing tools, resources and guidance to improve the incorporation of EJ considerations in our permitting. However, this rule will not affect the preconstruction permitting New Source Review programs, and this issue cannot be addressed by this rulemaking.

In response to one commenter's recommendation that additional studies and analyses be conducted, we agree that additional analysis would be helpful to better understand the impacts of air pollution, particularly Hg, on Native American populations. This rule addresses impacts of air pollution on Native American populations in that it regulates Hg air pollution from EGUs. The EPA's Office of Research and Development has undergone realignment to better address agency priorities, for which disproportionate exposure is of particular concern. This issue falls within the content areas of the Sustainable and Healthy Communities, Air, Climate and Energy, and Safe and Sustainable Water Resources research programs, which are working in a more integrated way with sustainable human and ecological well-being as the goal. Air pollution contamination of food fish falls within their work on multipollutant emissions, transport and cascading effects. This comment will be provided to those groups to ensure that these issues of critical importance to Tribal communities are given due consideration in research efforts.

Comment 7: Commenter 17732 generally supports the proposed NESHAP Rule in its goal of addressing reductions of HAP from stationary sources. The health and well-being of the natural environment and the people of the tribal nation are of utmost importance to the commenter. As a tribal nation and small government landlord of affected EGUs, the commenter states that the EPA is obligated to consult with the tribal nation and analyze the economic impacts to the nation in promulgating the proposed rule. The commenter further states that the EPA is required to tailor the proposed rule so that the costs of compliance for plants located on the tribal nation are achievable within a reasonable timeframe, while taking into account the unique challenges of the plants for this and future rulemakings. The commenter explains that compliance costs to meet BART have the potential to impact the tribal nation economy significantly. The commenter is concerned that the rule will create a recurring threat of severe reductions in the revenue received from the power plants and their supplying mines. The commenter asks that the EPA analyze the impacts from these rulemakings and provide flexibility for compliance scheduling so that EGUs upon which the Nation relies can continue operations.

Response to Comment 7: The EPA recognizes the concerns raised by the commenter as a tribal nation and small government landlord of EGUs, although landlords of affected facilities are not included in the definition of an affected small entity. The EPA estimated the potential impacts associated with complying with the rule on all entities that own affected EGUs, including those located on tribal nation land. We offered consultation to all tribal governments and conducted one-on-one consultation with the commenter. With respect to the compliance schedule, the EPA has provided the maximum 3-year period for sources to come into compliance as allowed by section 112 of the CAA. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. CAA section 112(i)(3)(B).

Comment 8: Commenter 17674 expresses concern with the EPA's presumption in the rulemaking that the NGS will close in 2015, citing the RIA where the EPA presumes that two of the three units would retire with or without implementation of the Utility MACT and the third would be forced to retire as a result of the economic and regulatory burdens imposed by the proposed rule. The commenter believes these assumptions are in contrast to prior statements by the EPA regarding the facility during the BART rulemaking. The commenter also believes the EPA must address the catastrophic impacts that the Utility MACT will have on Arizona tribes and reconcile these opposed positions.

Response to Comment 8: As mentioned previously, the EPA conducted extensive outreach and consultation on this rule. However, because of concerns raised by several tribes, and in order to help us better understand their concerns, we also participated in a face-to-face meeting with tribes in Arizona who were concerned about the potential impact of this rule on their income and water rights. Following that meeting, we held an additional technical meeting on how IPM is used in the RIA and provided one-on-one consultation with the Navajo Nation, Gila River Indian Community and the Ak-Chin Indian Community. We point out that IPM is used to analyze the power sector's cost-minimizing response to meet electricity demand with MATS in place. The EPA modeling and projections are intended to be a reflection of possible compliance using specific tools, assumptions, and methodologies that the agency believes reflect the best and most current information related to the power sector. It is not intended to reflect actual compliance decisions, since those will be made individually by the affected industry based on what makes most sense using existing technologies or other, more cost-effective strategies. Thus the EPA's IPM analysis of MATS does not dictate what a given facility must do to comply with MATS. Each facility may determine its own compliance strategy to meet the emission rate limits in MATS. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues as they arise. Public utility commissions and other authorities, such as tribes, will need to develop and implement compliance plans in order to address harmful emissions. We would point out that changes in the final rule are significant and will reduce costs, increase flexibility and alleviate industry concerns about achievability of standards.

Comment 9: Commenter 17674 discusses numerous considerations regarding NGS, suggesting it should be treated differently from other generating units because it is a unique facility with a significant federal purpose. The commenter notes that NGS powers the delivery of water, a trust resource, to fulfill the mandate of eight Congressionally-approved Indian water rights settlements, to Native American communities, and provides jobs both directly and through the associated coal mine.

Response to Comment 9: As discussed above, the EPA is sensitive to the commenters' concerns and intends to work with tribal and other authorities to ensure a smooth transition and address specific issues as they arise. However, we note that section 112 of the CAA imposes specific requirements with respect to the methodology the EPA must use in establishing emission standards for HAP, including Hg emissions from EGUs. The commenter suggests treating NGS differently from other generating facilities, and we interpret this comment at least in part as a request for a subcategory for NGS. Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. In the preamble to the proposed rule, the EPA further explains that any basis for subcategorizing (e.g. class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not agree that a subcategory based on location on tribal lands is consistent with the statutory authority to subcategorize, and the commenter does not explain why emissions would be different for EGUs located on tribal lands. Absent that showing, it would not be appropriate to subcategorize units even if we believed such a subcategory was consistent with the statute. Another commenter believes that there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units. The commenter points out that relaxation in standards would not only harm downwind governments and small businesses who incur higher labor costs due to pollution, but will harm other small businesses and state, tribal and local governments developing or operating generation facilities using modern and less polluting generation technologies. The methodology for determining emission standards under CAA section 112 does not result in requirements that specify the means of complying with standards. Thus, affected sources make their own determination regarding how they will comply with the standards. We believe that flexible and achievable pollution control requirements are promoted in the final rule through inclusion of alternative standards, alternative compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs.

Comment 10: Commenter 18017 states that if the proposed rule and other pending rules require installation of new control equipment costing hundreds of millions of dollars, the potential result could be early closure of their plant because the owners will be required to comply before they know whether the approvals necessary to operate after 2019 can be obtained. The commenter is concerned that the EPA may establish final emission limits governing NGS PM emissions that are so stringent that a new PM control will be required with compliance dates before approvals can realistically be obtained. The commenter asserts that this would lead to high compliance costs and could jeopardize continued operation of the NGS facility with severe economic impacts on numerous Indian Tribes.

Response to Comment 10: As the EPA has noted previously in this document, facilities that have or are already in the process of installing significant emission controls are likely to experience lower compliance costs as the result of this rule. Many coal facilities have already invested in pollution controls, and they are well positioned to comply with this rule with modest changes to operations. The EPA will work with relevant authorities to ensure a smooth transition with this rule and address specific issues as they arise.

Comment 11: Commenter 19686 states that the EPA needs to integrate the United Nations Declaration on the Rights of Indigenous Peoples (signed in December 2010) into the rule and other EPA actions. A number of federal entities including the Department of the Interior and Department of Justice are taking actions to implement the Declaration in their programs and policies. However, the EPA has been silent on how it plans to implement the Declaration. The rule is a good place for the EPA to start, making sure that the individual and collective rights of Tribes are protected and advanced in the EPA's efforts to reduce Hg and other toxic emissions from EGUs. The NTAA asks that the EPA inform our Tribal members about how it plans to implement the Declaration through the rule and other EPA actions with potential Tribal implications.

Response to Comment 11: The U.S. announced its support for the United Nations Declaration on the Rights of Indigenous Peoples in December of 2010. US agencies, including EPA, are currently engaged in many initiatives to address the issues in the Declaration. Consistent with the Declaration's call to develop a concept of self-determination specific to indigenous peoples, EPA has worked to strengthen the government-to-government relationship with tribes through the development and implementation of its May 4, 2011 Policy on Consultation and Coordination with Indian Tribes. Consistent with the important provisions of the Declaration that address environmental issues, in the development of this rule EPA encouraged tribal participation, by requesting data and information from the tribes to help us understand the impacts of the pollutant from the power plants in Native American Communities. Additionally, EPA conducted a series of outreach and consultation activities including consultation prior to proposal and post proposal, webinars, and onsite consultation with several tribes at their request. The EPA's discussion of EO 13175 includes additional details regarding EPA's consultation and coordination with Indian tribes.

Comment 12: Commenters 17846 and 19686 state that the Tribe and its members are greatly concerned about the environmental, health, and economic impacts of Hg deposition from coal-fired EGUs. Because of this, commenter 17846 commends the EPA for proposing a rule that, in accordance with the requirements of CAA section 112, applies the same emission limits to all EGUs within a subcategory. This is critical to avoid the creation of Hg "hot spots," which could leave large portions of Indian country susceptible to continuing Hg contamination.

Response to Comment 12: The EPA acknowledges commenters' concerns and appreciates their support of this important rule that will reduce emissions of Hg and other air toxics.

Comment 13: Commenter 19686 states that the EPA has failed to provide Tribes with any assurances that their communities and land will not be part of Hg emission hotspots as a result of the rule's implementation. The EPA has a trust responsibility to Tribes that requires it to look out for the general welfare of such Tribes when taking actions with potential Tribal implications. The commenter recommends that the EPA develop a plan for dealing with hotspots that affect Tribes. In addition, the EPA must provide Tribes with a map overlay of Tribal lands and EGUs so that Tribes can have a better understanding of how the rule might impact them.

Response to Comment 13: In the final rule, the EPA established technology-based standards consistent with the requirements of CAA section 112(d). Such standards require all sources within a source category or subcategory to reduce HAP emissions to the same level without consideration of risk. To determine whether additional standards are necessary, the EPA will consider whether risk remains from HAP emissions from a source category within 8 years of promulgating final section 112(d) standards pursuant to section 112(f)(2). We encourage the commenter's suggestions on how to continue to minimize the potential local impact of Hg from these sources as the rule is implemented. The EPA will provide any non-privileged available information relevant to Hg deposition in Indian country in response to a request from the tribe. Finally, we encourage tribes to work with the EPA as it considers the risk to public health, including tribal members, in determining the need for further standards as the EPA reviews these standards consistent with the statute.

Comment 14: Commenter 17846 states that the Tribe and its members are greatly concerned about the environmental, health, and economic impacts of Hg deposition from coal-fired EGUs. Because of this, The Fond du Lac Band of Lake Superior Chippewa commends the EPA for proposing a rule that, in accordance with the requirements of section 112, applies the same emission limits to all EGUs within a subcategory. This is critical to avoid the creation of Hg "hot spots," which could leave large portions of lndian country susceptible to continuing mercury contamination.

Response to Comment 14: The EPA shares the tribes concerns about Hg and its potential impact on tribes. We believe this rule will prevent local hotspots from occurring.

7G - Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

Commenters: 10822, 12462, 16121

Comment 1: Commenter 10822 provides a copy of a journal article entitled “Pregnancy Loss and Maternal Methemoglobin Levels: An Indirect Explanation of the Association of Environmental Toxics and Their Adverse Effects on the Mother and the Fetus.” According to the abstract, the aim of this epidemiologic study was to point out a relationship between the exposure to products of coal combustion, and complications in pregnancy where one third of causes of stillbirth are still unknown.

Comment 2: Commenter 12462 notes Hg is of special concern to Tribal children and women of childbearing age, as Hg is a neurotoxin that causes neurological delays and damage. The commenter states in utero exposure to Hg, via contaminated fish eaten by expectant mothers, can impair thinking, memory, attention, language, and fine motor and spatial skills. Additionally, the commenter states that children who eat Hg-contaminated fish are at risk for decreased brain function.

Comment 3: Commenter 16121 supports the EPA for its proposal to reduce Hg and other harmful emissions, stating the American public, especially vulnerable populations such as pregnant women and children, is currently not adequately protected from Hg exposure in the environment. The commenter briefly summarizes Hg issues related to health effects and exposures for these populations.

Response to Comments 1 - 3: The EPA acknowledges the concerns of all three commenters and appreciates their input regarding health effects of Hg and other coal combustion emissions. In addition, the EPA thanks commenter 16121 for their general support of the proposal.

7H – Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

Commenters: 18447

Comment 1: Commenter 18447 suggests that, despite the EPA's conclusion, the rule is likely to have adverse effect on the supply, distribution, or use of energy, and the EPA downplays the impact of the rule with respect to the costs that the taxpayers and U.S economy must bear, which the commenter believes are substantial.

Response to Comment 1: As discussed extensively elsewhere in this document, the preamble to the final rule, the RIA, and other supporting materials, the EPA disagrees with commenter and maintains that the EPA's analysis of the rule is reasonable, and does not understate impacts as the commenter suggests.

7I - National Technology Transfer and Advancement Act

No comments were received specifically on the National Technology Transfer and Advancement Act (NTTAA) or its requirements. To the extent that the NTTAA is referenced in the context of comments regarding another topic it has been addressed as appropriate.

7J - Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Commenters: 17254, 17681, 17697, 17710, 17713, 17766, 18433, 18934, 19145, 19210, 19536/19537/19538

1. General comments regarding impacts on minority and low-income populations.

Comment 1: Commenter 17254 presents a map showing the close correlation between the location of populations below the poverty line expected in 2016 and the locations of power plants. The commenter states that while the EPA developed these maps to show the potential impacts from fish consumption in nearby waterways, the evidence also shows that these populations face higher risks because of the air they breathe.

Commenter 17254 notes that coal-fired power plants are disproportionately located in or near low income and minority communities. The commenter states that 68% of all African Americans in the U.S. live within 30 miles of a power plant, as opposed to 56% of whites. The commenter also notes that even though African Americans compromise 13% of the U.S. population, they account for 17% of the population living within 5 miles of power plant waste sites.

Comment 2: Multiple commenters (17524, 19210, 19536, 19537, 19538) note that disadvantaged communities that rely on the extra source of protein from fishing shoulder a disproportionate share of the impact from Hg pollution. Commenter 17524 cites a study that Sierra Club commissioned from Bendixen and Amandi, a polling firm, in which increased risks to the Hispanic community are identified from fishing in urban communities, where fish caught tend to have the highest concentration of Hg contamination. The commenter notes that the study reports that Hispanics in California consume almost twice the EPA safe limit of Hg due to subsistence fishing.

Response to Comments 1 - 2: The EPA agrees that minority and low-income populations are overrepresented among those persons who live in close proximity to coal-fired power plants and that certain low income and minority community members (such as subsistence fishers) consume higher levels of fish that may be contaminated by Hg. For these reasons, the EPA expects that minority, low-income and indigenous population groups would benefit disproportionately from the reduced emissions that will result from the rulemaking, both in terms of reduced inhalation of pollutants and reduced ingestion of Hg-contaminated fish.

Comment 3: Commenter17681 requests that the EPA work towards developing scientific evidence of EGU's impact on Hg blood concentrations in at risk populations, such as minorities and the elderly. The commenter notes that they are cautious to endorse a rule which will financially impact such populations to great extent while at the same time it is witnessing unexplained substantial reductions in blood Hg concentrations of all population classes according to the EPA's National Health and Nutrition Examination Survey (NHANES) data.

Response to Comment 3: First, the EPA has developed an analytical method to estimate the impact of Hg emissions from U.S. EGUs on Hg fish tissue concentrations and the implications for human health, as documented in the National-Scale Mercury Risk Assessment. Second, the EPA disagrees that there is a statistically discernible downward trend in the NHANES data on blood Hg. The EPA is unaware that a formal statistical analysis for temporal trends has been completed for NHANES data on blood Hg levels for the period 1999 to 2008. Mahaffey et al. 2009, evaluating NHANES data collected 1999 to 2004 for women at child-bearing age, could "not support the conclusion that there was a general downward trend in blood mercury concentrations over the 6-year study period." However, the same publication noted that "there was a decline in the upper percentiles reflecting the most highly exposure women" having blood Hg concentration greater than established levels of concern. Visual observations of the data show a slight decrease in Hg blood level concentrations from 1999-2008 at the geometric mean. This decrease may not be statistically significant based on overlapping confidence intervals. A decrease in Hg blood level concentrations is also observed at the 95th percentile. Except for differences observed between 1999 and 2008, the temporal decrease may not be statistically significant. Conclusions cannot be drawn without further and more formal statistical analysis of the data.

The EPA remains concerned that substantial numbers of women of childbearing age in the U.S. may have blood Hg levels that are equivalent to exposures at or above the RfD. Mean and 95th percentiles from recent NHANES data are below 5.8 ug/l (a blood Hgy concentration equivalent to the RfD). However, blood levels for some portions of the population (high consumers of fish, for example) may be indicative of exposures above the RfD. The EPA did not find data for NHANES blood distributions above the 95th percentile. Modeled data from Tran et al., 2004 provided estimates showing high blood Hg levels at the 99th percentile for females of child-bearing age (i.e., 24.41 ug/L at the 99th percentile). Mahaffey et al. 2009 showed that 2.4% of women of child-bearing age had blood Hg values above 5.8 ug/L. Other published studies have shown that various population groups can have high blood Hg levels (Mahaffey 2005; Miranda et al. 2011; Hightower and More 2003; Hightower et al. 2006; McKelvey et al. 2007). For example, in Hightower et al. 2006, the authors found that Asian populations had Hg exposures greater than 5.8 ug/L in 83% of the Asian population compared to 12% for the total survey population.) (Butler Walker, J., J. Houseman, et al. (2006). "Maternal and umbilical cord blood levels of mercury, lead, cadmium, and essential trace elements in Arctic Canada." Environ Res 100(3): 295-318; Hightower, J. M. and D. Moore (2003). "Mercury levels in high-end consumers of fish." Environ Health Perspect 111(4): 604-608; Hightower, J. M., A. O'Hare, et al. (2006). "Blood mercury reporting in NHANES: identifying Asian, Pacific Islander, Native American, and multiracial groups." Environ Health Perspect 114(2): 173-175.)

Comment 4: Several commenters (17697, 17710, 18433) note that Guam is designated as a "distressed nonmetropolitan middle-income" area due to both high poverty and unemployment rates, yet its utility costs are among the highest in the nation. Given these circumstances, commenter 17710 requests that the EPA consider relief for the Guam Power Authority (GPA) from the final rule.

Commenter 17710 suggests the compliance costs and risks associated with the rule would require significantly increased electricity rates that could cause economic hardship on its customers, such as the unemployed, underemployed and those with limited or fixed incomes.

Response to Comment 4: The EPA disagrees that the rule will result in significantly increased prices for electricity. The increase in electric rates to consumers as shown in the RIA will be 3.7% on average nationally by 2015. These increases are accompanied by substantial benefits to health from the emission reductions that will take place across the country due to this rule. The increased price information is factored into the agency's decision making and is discussed in more detail in the RIA. States and local entities responsible for utility rate structures are best positioned to deal with economic impacts on low income customers and with the overall distribution of increased costs.

The EPA expects that the general population, including low income persons, would experience significant health benefits as a result of this rulemaking. The standards would prevent as many as 17,000 premature deaths and 11,000 heart attacks a year and would provide particular health benefits for children, preventing 120,000 cases of childhood asthma symptoms and about 11,000 fewer cases of acute bronchitis among children each year. The EPA estimates that for every dollar spent to reduce pollution from power plants, the American public and American businesses will see up to $13 in health and economic benefits. It is also likely that household income for some low income families may increase if individuals are able to work (or work more) as a result of improved health.

Finally, the EPA has acknowledged the unique circumstances of non-continental liquid oil-fired EGUs, such as those on Guam, and adopted specific provisions for them in the final rule.

Comment 5: Commenter 18934 suggests that in the case of EJ communities, more extensive reductions beyond that required to meet the average level achieved by the top 12% of plants be required as such technology exists. The commenter offers to work with the EPA to further define EJ communities for such a purpose.

Response to Comment 5: CAA section 112(d) standards are technology-based standards. Pursuant to section 112(d)(3), the EPA establishes MACT floor limits for existing sources based on the best performing 12% of sources. After establishing the MACT floors, the statute requires the agency to determine whether standards more stringent than the MACT floor are achievable after considering the costs of achieving such additional emission reductions and the non-air quality health and environmental impacts of more stringent standards. CAA section 112(d)(2). The EPA has conducted an analysis consistent with section 112(d)(2) for this rule and determined that a more stringent standard is achievable for one pollutant from one existing source subcategory. As the D.C. Circuit recognized in *Sierra Club v. EPA,* 353 F.3d 976 (D.C. Cir. 2004:

"These [112(d)(2) and (d)(3)] emission standards are to be based not on an assessment of the risks posed by HAP, but instead on the maximum achievable control technology (MACT) for sources in each category. Senate Report, at 148 ("The MACT standards are based on the performance of technology, and not on the health and environmental effects of hazardous air pollutants."). The standards, at a minimum, must reflect the emissions limitation achieved by the best-performing sources in a particular category. . . The idea is to set limits that, as an initial matter, require all sources in a category to at least clean up their emissions to the level that their best performing peers have shown can be achieved." 353 F.3d at 990.

In *Sierra Club*, Sierra Club argued that the phrase "non-air quality health and environmental impacts" in 112(d)(2) required the EPA to consider the "impacts of deposition, persistence, toxicity and bioaccumulation of metal HAP emissions on people, wildlife and the environment." The Court rejected this argument and upheld the EPA's interpretation of the phrase, which was that "'non-air quality ... impacts' refers to any health and environmental impacts ... that may result directly or indirectly from [the control] measures that will achieve the emission reductions." 353 F.3d at 990-91. The Court further held that "Sierra Club's interpretation would collapse the technology-based/risk-based distinction at the heart of the Act, undermining the central purpose of the 1990 Amendments." *Id.* The commenter here seeks to infuse risk into setting technology-standards, which is not permissible.

Within 8 years after the EPA promulgates section 112(d) standards, section 112(f) directs the agency to evaluate the risk remaining after implementation of the MACT standards to determine whether the standard provides an ample margin of safety to protect public health. The EPA will consider risks posed to disadvantaged communities in that evaluation, but any resulting standards must be national in their scope and applicability. To the extent that any given community is seeking greater protection than a national rule would provide, we encourage them to work with the appropriate State and local authorities to fashion solutions that are specific to their community.

Comment 6: Commenter 19145 provides several statistics on the disproportionate impacts related to African Americans and power plants. The commenter uses these statistics to show pollution from power plants is an issue of racial disparity as African Americans are most likely to be exposed to the toxins coming from power plants and the impact is apparent through the higher rates of infant mortality, low birth weight, and premature births among the population. The commenter also notes that the African American population has increased rates of asthma, with power plant pollution being a contributing factor to asthma and chronic bronchitis.

Response to Comment 6: The EPA agrees that minority populations, including African Americans, generally have worse health than whites and that many minority and low income communities are overburdened by air pollution. The EPA agrees that the African American population has increased rates of asthma compared to other population groups and that pollution from power plants can be a contributing factor to asthma and chronic bronchitis. To that extent, African Americans living in the vicinity of power plants can be expected to receive disproportionate benefits from the rule's implementation.

Comment 7: Several commenters (19536, 19537, 19538) believes information gathering and better understanding of the cumulative health impacts in areas where many sources of HAP are located together, such as industrial areas, would be beneficial for addressing EJ concerns.

Response to Comment 7: The EPA generally agrees with the value of assessing cumulative impacts in such areas, and that additional data would be useful in that process, but collection of these data is outside the scope of this regulatory action.

2. The EPA did not meet requirements of EO 12898.

Comment 8: Commenter 17713 believes the Environmental Justice Statement included in the proposed rule does not meet the requirements of EO 12898 as it failed to address increased electric rates to consumers that will cause disproportionate harm to minority, fixed-income and low-income populations, as well as health impacts from the decreased disposable incomes that these consumers would have to spend on health care, food, cooling and heating, and housing.

Response to Comment 8: The EPA does not agree with the commenter's assertion that the agency failed to consider the impacts of increased electric rates to consumers, including minority, fixed income and low-income populations. The commenter also makes an assertion which relies on a theory that the cost of a rule will result in lost income that will, in turn, result in negative health effects that offset the positive health effects of the rule. (This is sometimes referred to as a "health-health tradeoff.") The EPA also disagrees with this claim and notes that there are a number of conceptual and empirical problems with any attempt to quantify the health-health tradeoffs of regulatory action to control air pollution. Claims about health-health tradeoffs rely on questionable applications of cross-sectional data and ignore key factors that may influence changes in population health risks. Additionally, marginal decreases in household income caused by the pass-through costs of the regulation are unlikely to cause large changes in any single aspect of household spending, such as health care. These analyses also fail to consider that household income may increase if individuals are able to work (or work more) as a result of improved health, offsetting some or all of the pass-through costs of the rule. For these and other reasons, the

EPA's science and economic peer review panels have consistently advised against incorporating alleged health-health tradeoffs in the EPA analyses of regulatory effects.

The agency's rule requires reductions of HAP such as Hg, arsenic, lead and other metals, that are shown to cause serious injury to exposed populations. The benefits of Hg and HAP emission reductions, along with the substantial benefits from reductions in emissions of PM, SO_2, and other pollutants are shown in our RIA. Populations that are the focus of EO 12898 will benefit from these reductions as shown in the RIA. In addition, the increase in electric rates to consumers as shown in the RIA will be 3.7% on average nationally by 2015, with some consumers in certain regions seeing increases of less than 10% while other consumers in different regions will see increases of only 1%. These increases in electric rates may not be minimal in some areas of the U.S., but they should be seen in light of the substantial benefits to health from the emission reductions that will take place across the country due to this rule.

Comment 9: Commenter 17713 believes the Environmental Justice Statement failed to consider the cumulative impacts of the rule in addition to other power sector rules, which disproportionately impact lower income, elderly and minority populations. The commenter cites an economic analysis prepared by National Economic Research Associates for the American Coalition for Clean Coal Electricity (ACEE) showing estimated increases in electricity prices, natural gas prices, and loss of jobs from the combined impacts of the proposed rule and the CSAPR. The commenter also includes in their comment a copy of a January 2011 publication entitled "Energy Cost Impacts on American Families, 2001-2011" and cites a March 2010 study performed for the Affordable Power Alliance by Management Systems, Inc. on the effect of GHG regulations, both of which conclude that there are disproportionate impacts on low income and minority groups from these regulations.

Response to Comment 9: As discussed above, the EPA disagrees with the assertion that the rule will result in disproportionate negative impacts on low-income, elderly, and minority populations. The EPA believes this rule will provide significant benefits to all citizens, including minority, low-income and indigenous populations. Furthermore, the EPA has recently assessed the cumulative impact of regulations adopted to implement the 1990 CAA Amendments. In March 2011, the EPA issued the Second Clean Air Act Prospective Report which assessed the benefits and costs of regulations pursuant to the 1990 CAA Amendments. The study examines the cumulative impact of these regulations (found at http://www.epa.gov/air/sect812/feb11/summaryreport.pdf). As shown in the report, the direct benefits from the 1990 CAA Amendments reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at http://www.epa.gov/air/sect812/prospective2.html. The direct benefits of the 1990 CAA Amendments and associated programs significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits exceed costs combined with extensive uncertainty analysis suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. The EPA believes the same conclusion applies to this rulemaking, as discussed in the RIA.

The economy as a whole is also stronger with 1990 CAA Amendment programs as cleaner air leads to better health and productivity for American workers and less money spent on health care to treat air pollution-related health problems. Economy-wide modeling shows that long-term economic growth is greater and American household economic welfare is improved because benefits such as fewer sick days and lower medical costs more than offset the economy-wide cost of investing in air pollution control.

Comment 10: Commenter 17713 suggests that high energy prices from the rule will lead to businesses cutting costs by laying off workers, with low-wage workers being the groups that will be impacted by such layoffs. The commenter notes that low-wage workers are disproportionately Black and Hispanic.

Response to Comment 10: As discussed elsewhere in this document, the EPA's analysis shows that high energy prices will not result from this rule, and increases are expected to be 3.7% on average nationally by 2015. The EPA estimates that the overall impact on short-term employment will be an increase on net of 46,000 jobs associated with the rule, with an increase in long-term jobs annually of 9,000 (with jobs being measured as job-years, or 1 year of employment for one full-time worker). The range of employment impacts in the long-term is a loss of 15,000 to a gain of 30,000 jobs. Thus, any lay-offs will be smaller than the number of jobs expected to be supported or created from compliance with the rule.

Comment 11: Commenter 17713 believes the EPA's regulations will significantly impact the cost of all fossil fuels, leading to an increase in prices of all basic goods, disproportionately impacting minority populations. The commenter provides statistics showing the percentage of income spent on food, housing and clothing by minority populations in comparison to Whites.

Response to Comment 11: Although there may be increases in price for electricity, natural gas, and coal associated with this rule, it should be noted that the increase in electricity price to consumers is less than 4% by 2015, and the increase in natural gas price on average from 2015-2030 is less than 1.5%. These estimates are presented in the RIA for the rule. Thus, these increases are unlikely to significantly affect the prices of basic goods, and are modest when considering the substantial benefits from reductions of HAP and other pollutant reductions that this rule is expected to achieve. These benefits will be enjoyed by minority populations, as well as other populations, and to a disproportionate extent for those living in the vicinity of power plants.

Comment 12: Commenter 17713 notes that the combined impacts from increased unemployment, reduced incomes, and increased prices for housing, basic necessities, energy, and utilities resulting from the EPA regulations will further reduce Black and Hispanic discretionary incomes.

Response to Comment 12: As discussed elsewhere in this document and the preamble to this rule, the EPA provides estimates of the impact of this rule on energy prices, unemployment, and prices for industries affected by any predicted increases in energy prices in the RIA for this rule. As stated above, the EPA expects that the impacts of increased electricity prices would be small and would be more than offset by increases in employment and the substantial benefits from reductions of HAP and other pollutant reductions that this rule is expected to achieve.

3. The EPA met requirements of EO 12898.

Comment 13: Commenter 17766 believes the current rule as written, would significantly protect minority and low-income populations living near coal- and oil-burning EGUs by lowering Hg, HAP, and fine particulate emissions in the air and in turn Hg in water and accumulated in fish.

Response to Comment 13: The EPA agrees with this comment.

7K - Statutory and Executive Orders: Other

Commenters: 15182, 16705, 17295, 17400, 17697, 17710, 17824, 18038, 18433, 18433, 18575, 19042, 19213, 19580

Comment 1: Commenter 15182 requests that the EPA further regulate emissions from power plants to meet the goal of achieving zero emissions of nine critical pollutants (including Hg) by 2020, which the EPA and other signatories established under the Binational Program to Restore and Protect Lake Superior.

Response to Comment 1: Reductions in Hg and other emissions from this action are modeled for full compliance in 2016. Although this action is neither intended nor required by the CAA to achieve the zero emissions target of the Binational Program to Restore and Protect Lake Superior, it is a critical step toward significantly reducing overall emissions of these pollutants in support of that goal by the year 2020.

Comment 2: Commenter 17751 believes the proposed rule does not adequately comply with EO 13563, EO 12866, the RFA or UMRA. The commenter also believes the proposal does not show the proposed emissions reductions would have substantial benefit, ignores the "dwarfing" presence of Hg from natural sources, and attempts to justify the rule almost completely from alleged co-benefits. The commenter also notes that the proposal does not fully consider that state of scientific knowledge, is duplicative of other regulatory programs, violates the requirements of the Information Quality Act (IQA), and fails to carry out the requirements of UMRA and EO's to compare costs and benefits of alternative regulatory approaches, including no regulation.

Response to Comment 2: The EPA has complied with all applicable statutory and executive order requirements in the preparation of this rulemaking. The RIA for the proposed rule does show that the emission reductions from this rule would result in substantial benefits (on the order of $50 to over $100 billion). Accounting for ancillary benefits is standard practice in benefit-cost assessment since these benefits are a consequence of the rule, regardless of the rule's intended purpose. As such, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible, for the purpose of determining the likely impacts, not to justify an action. This rule is expected to achieve substantial $PM_{2.5}$ health benefits resulting from primary PM and SO_2 emission reductions and are, thus, an important category to quantify. Consideration of ancillary benefits in benefit-cost analysis is directed by OMB Circular A-4.

Comment 3: Multiple commenters (16705, 17295, 17400, 17697, 17710, 18038, 18433, 18575, 19213) request that the EPA evaluate the impact to their utility under the SBREFA, UMRA, EO 13563, EO 13132, EO 12866 and EO 13211 based on their concerns with the proposed rule. The commenters state that they have standing under these Executive Orders to call for reasonable and cost-effective regulations to achieve reductions in air pollution in a reasonable timeframe.

Response to Comment 3: The EPA has complied with all applicable statutory and executive order requirements in the preparation of this rulemaking. All utilities that the agency expects will be impacted by this rule have been included in all analyses completed as part of compliance with the applicable statutory and executive order requirements. The results of these analyses are contained in the RIA for this rule, in various TSD) prepared for this rule, and the results are summarized in the preamble for this rule. Results of these analyses are available in various level of detail in the RIA and the TSDs, and the detailed results can be found in the docket for this rulemaking and through the official web site for this rule. In adopting a final rule establishing national emission standards, the EPA is not required to conduct individual plant-specific analyses under the cited statutes and executive orders.

Comment 4: Commenter 18575 requests that the EPA review the impacts of the proposed rule on a "least cost to society basis," pursuant to EO 13563, 12866, 13211, and 13132, as the commenter believes the EPA can propose less costly, yet still protective, alternatives to the proposed rule.

Comment 5: Commenter 19580 recommends the EPA more closely follow the existing requirements for promulgating regulations and actually conduct detailed analysis prior to rulemaking. This analysis would include: a review of the EPA's IQA Guidelines; a detailed RFA analysis to determine the impact of a regulatory action upon small businesses before certifying that there is no significant economic impact; UMRA analysis to determine the least costly, most cost-effective, or least burdensome alternative that achieves the objective of the rule; and PRA analysis to determine if OMB approval is needed to meet information collection requirements.

Response to Comments 4 - 5: The EPA is obligated to meet the relevant requirements of the CAA. In doing so, the agency developed control strategies in the proposal that would show how affected EGUs could meet these requirements at least cost to them consistent with the requirements of the rule. In addition, the agency is mindful of mitigating the cost to society as part of this regulatory effort and completed economic impact analyses for this rule that examined the impacts not only to the electric power sector but to sectors outside of the power sector. These analyses are in the RIA for the rule. The agency also completed analyses and consultations in compliance with the stated Executive Orders; the OMB and other federal agencies reviewed these analyses and was aware of the consultations. All of the analyses are in the RIA and in other documents within the docket for this rulemaking; documentation for the consultations are in the docket as well.

Comment 6: Commenter 19042 suggests the Obama Administration has, with limited transparency and no Congressional and industry scrutiny, promulgated a complex scheme of Executive Orders, reports, scorecards, and associated documents that assert implementation of various environmental regulations will reduce costs to the federal government and industry without any supporting analytical regulatory documentation. The commenter notes several sustainability goals identified by EO 13514 and imposed by the CEQ, noting that as a result of the proposed Utility MACT standards, utility costs will increase within the federal budget, obviating any potential savings claimed by the Obama Administration due to implementation of EO 13514.

Response to Comment 6: In adopting today's final rule, the EPA has complied with the statutes and all relevant executive orders, and has provided extensive documentation in support of its technical and economic analyses. To the extent that the commenter is questioning other actions taken by the Executive Branch, this comment is outside the scope of this rulemaking.

Comment 7: Several commenters (19536, 19537, 19538) maintains that because endangered, threatened and other protected species have been documented with high levels of Hg, and the livelihood and reproductive success of these creatures can be affected by this and other hazardous pollutants, the EPA is required to consult with the appropriate agencies to determine the levels at which emissions need to be set not only as required under the Endangered Species Act (ESA) section 7(a)(2) but also to meet the EPA's ESA section 7(a)(1) duty to determine how the EPA can use its authority to enhance the recovery of these species.

Response to Comment 7: The EPA generally agrees that such species are threatened by high levels of Hg and other HAP and that actions to reduce those levels is appropriate. However, the commenters are incorrect in their assertion that the EPA must conduct an ESA consultation in this action. In a challenge to the NESHAP for primary copper smelters, the D.C. Circuit held that the ESA does not apply to the MACT standard setting process under CAA section 112(d). *Sierra Club V. EPA*, 353 F.3d 976, 992 (D.C. Cir. 2004).

CHAPTER 8: RULE LANGUAGE CORRECTIONS

8A - Rule: Definitions (existing)

Commenters: 17174, 17316, 17386, 17402, 17620, 17623, 17648, 17681, 17690, 17715, 17716, 17721, 17725, 17728, 17733, 17754, 17756, 17771, 17775, 17796, 17800, 17801, 17804, 17805, 17808, 17812, 17818, 17821, 17838, 17843, 17846, 17855, 17870, 17878, 17880, 17881, 17904, 17914, 18024, 18025, 18031, 18034, 18425, 18427, 18444, 18483, 18498, 18963, 19040, 19114, 18023

Several commenters requested that the EPA review the proposed definitions for consistency and clarity.

1. Definition of natural gas.

Comment 1: Multiple commenters (17174, 17801, 18483, 17878) request that the EPA review and revise the definition of natural gas to be consistent with the NSPS. For natural gas, the third element of the NSPS definition is excluded in the NESHAP definition (i.e., "A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 % methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot)"). Commenters 17801 and 17878 state that by excluding this provision, IGCC or other generating units will be subject to the same standards as coal-fired boilers despite the fact they burn substitute natural gas (SNG), which is the same chemically as natural gas. Should such IGCC or other generating units remain subject to the rule, fuel sampling should be allowed as a compliance demonstration option in lieu of a Hg CEMS or sorbent trap methodology due to Hg being removed from the fuel prior to combustion and the absence of post-combustion Hg controls. If the EPA decides that the definitions should have different scopes and limitations, the reasons for the divergent definitions should be clarified. Commenter 17174 also requests that the EPA use the definition for distillate oil in the subpart Db NSPS, which contains a limitation on the weight % nitrogen, while the proposed definition for the Utility MACT does not.

Response to Comment 1: The EPA concurs with the commenters concerning the definition of natural gas from the NSPS and has made the suggested revisions to the 40 CFR subpart UUUUU definitions in the final rule so as to be consistent with 40 CFR Part 75. Concerning the IGCC units, EPA must regulate such units if the gas at issue is derived from coal or oil and EPA is listing coal- and oil-fired EGUs. Although EPA believes that IGCC units could sample the gas stream before it enters the turbine, as noted elsewhere in this document, EPA has dropped fuel sampling, and, thus, the issue is moot. Owners or operators of IGCCs will need to perform instrumental monitoring (Hg CEMS or sorbent traps) or quarterly emissions testing for mercury.

> <u>Natural gas</u> means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 % methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

2. Definition of EGU.

Comment 2: Several commenters (17620, 17316, 17805) request that the EPA clarify in the final regulations what the "25 MW" in EGU definition references. Commenter 17316 questions whether the 25 MW EGU threshold refers to the power supplied to the grid (i.e., the net MWs) or the power generated by the EGU (i.e., the gross MWs). The commenter indicates that the 40 CFR 60.2 definition of EGU implies that the net MW is of more relevant concern. Similarly, Commenter 17620 recommends that the EPA specify whether the unit can produce more than 25 MWe is based on its maximum rated capacity, short-term peak capacity, or if it is based on the unit's current ability taking into consideration the age of the unit and its thermal efficiency.

Comment 3: Commenter 17805 requests that the EPA clarify that the definition of EGU is assessed by reference to the maximum electrical generating capacity of the generator the combustion unit serves. Thermal units, or boilers, are not, from an engineering standpoint, assigned MW or MWe ratings in design or specification and are only known to be assigned to generator electric output (i.e., to the generators a boiler serves). Thus, the thermal capabilities of a combustion unit are specified by reference to generator output. The commenter requests that the definition of EGU should therefore be revised as follows:

> "Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit serving a generator of more than 25 megawatts (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit."

Comment 4: Commenter 18425 states that the definition of EGU is unclear for two reasons:

- The phrase "of more than" can have multiple reasonable definitions (e.g., that a facility has the capability to produce 25 MWe or that the facility is actually producing 25 MWe). The commenter recommends that the definition should be clarified that EGUs will be affected by the proposed rule if they are capable of producing 25 MWe rather than only when they produce 25 MWe during operation.
- It is unclear if cogenerating units can be classified as EGUs using the first sentence of the definition as it is currently written. The commenter recommends that the definition specify whether cogenerating units apply.

Comment 5: Commenter 17818 supports the proposed definitions for fossil fuel, fossil fuel-fired and the specification that an EGU must have fired coal or oil for more than 10.0 % of the average annual heat input during the previous three calendar years or for more than 15.0 % of the annual heat input during any one of those calendar years to be considered a fossil fuel-fired EGU but indicates that the provision for combusting more than "73 megawatt-electric (MWe) (250 million British thermal units per hour, MMBtu/hr) heat input (equivalent to 25 MWe electrical output) of coal or oil" is confusing. The commenter suggests that it would seem to be more appropriate to consistently relate MW thermal as fossil fuel fired heat input rather than MW electric (73 MW, or 73 MW thermal, or 73 MWhr/hr).

Comment 6: Alternatively, Commenter 17316 states that depending on the heat rate of an EGU, it may require more or less than 250 MMBtu to generate 25 Mw of electricity. The commenter states that referencing 250 MMBtu/hr as a threshold marker is confusing and 25 Mw alone should be used as the applicability threshold in all Sections of the rule for consistency and clarity.

Comment 7: Commenter 17386 states that the definition of "Electric utility steam generating unit" provided in section 63.10042 of the proposed rule seems to include inconsistent designations. The definition suggests the 25 MW threshold is a gross value for EGUs that output electricity only (1st sentence) and a net value for EGUs that output steam and electricity (2nd sentence): "Electric utility steam generating unit means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit."

Commenter 17386 states that classifying EGUs based on their gross MW capacity, for EGUs that output electricity also conflicts with the 40 CFR 60 definition that implies the 25 MW threshold is based on net electrical output, as identified below: "Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility."

Commenter 17386-A2, therefore, requests that the EPA clarify the rule to identify whether the 25 MW applicability threshold is based on gross electricity generation or net electrical output. The commenter also recommends utilizing the 25 MW net electrical output approach consistent with the 40 CFR 60 definition in all sections of the MACT rule for consistency and clarity.

Comment 8: Commenter 17818 supports the applicability cutoff limit of greater than a 25 MWe rating level, but questions the applicability of the proposed rule to EGU's that have an actual "nameplate" rating capacity of 25 MWe or less but have actual demonstrated outputs of greater than 25 MWe. Numerous examples of units with nameplate capacity listed as 25 MWe or less have demonstrated summer and/or winter outputs of greater than 25 MWe, as documented in EIA listings. Conversely, the EIA listings also identify EGUs with 25 MWe nameplate capacities that have actual demonstrated output ratings less than 25 MWe. Such units that have actual ratings below the original nameplate may have permit restrictions or other cycle restrictions that prevent the unit from attaining actual outputs greater than 25 MWe. Units with 25 MWe nameplate rating but have demonstrated generation outputs in excess of 25 MWe may have been under-rated from the manufacturer or may have undergone modifications or operating practices that increase the output in excess of that anticipated by the generator manufacturer. Commenter believes that the EPA must consider these circumstances in determining unit applicability.

Comment 9: Commenters 17818 and 17843 support the EPA's proposed EGU exemptions as listed in paragraphs (a) through (c) of section 63.9983.

Comment 10: Commenter 18031 agrees with the EPA's expanded EGU definition which supports renewable energy from biomass, however clarification is needed to ensure that boilers which provide steam to a generator <25 MW are not considered EGU's under the proposed EGU MACT Rule. Commenter currently owns and operates four units that burn a combination of biomass, coal, and natural gas. Commenter is in the process of upgrading these facilities in order to provide for even more biomass generation to help meet a state mandate of 25 % renewable energy by 2025. Careful wording of the definition of an EGU in the proposed EGU MACT Rule is important to ensure the viable future of these renewable energy sources.

Commenter 18031 states that the EGU definition in the proposed EGU MACT Rule allows for up to 10 % coal on a 3-year basis, and up to 15 % on a one-year basis, and these units would still qualify as industrial boilers, even though the rated capacity is greater than 25 MW per unit. Two of Commenter's four biomass units (located at the Hibbard Renewable Energy Center) are greater than 25 MW rated capacity of the turbine/generator. Allowance for the use of coal for start-up and flame stabilization is important due to the nature of the woody biomass combustion characteristics at these units. Biomass heat content can vary from 2000 to 6500 Btu/lb with a moisture content ranging from 24 % to 65 %. Coal helps to reduce the impact of this variability, resulting in better combustion and increased operational stability.

Commenter 18031 states that because of the small size of these units, the emphasis on renewable biomass generation, and the fact their primary function historically has been to provide steam to an industrial process (paper mill), the Hibbard Renewable Energy Center boilers are more properly classified as industrial boilers, not EGUs. Commenter supports retaining the language in the EGU definition that would allow the continued use of coal for start-up and flame stabilization, and yet classify these boilers as industrial boilers, not EGUs.

Commenter 18031 states that two of their boilers that burn primarily biomass were primarily designed as industrial boilers to provide steam to a co-located paper mill. These two solid fuel boilers are both rated at greater than 250 MMBtu/hr (270 MMBtu/hr), however the turbine/generator each unit serves is less than 25 MWe, so these boilers should be classified as industrial boilers, not EGUs. CAA section 112(a)(8) defines an EGU as: "a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale…… " . …Since the boilers do not feed turbine/generators greater than 25 MWe, and have a primary purpose of providing steam to a paper mill, they should not be classified as utility boilers. These boilers are more properly defined as industrial boilers, and should fall under the Industrial Boiler MACT requirements. The definition of an EGU in the final EGU MACT Rule should not require boilers rated at greater than 250 MMBtu/hr, but serving a generator <25 MW, to meet the EGU MACT emission limits and other requirements.

Comment 11: Commenters 17316 and 17386 state that section 63.9983(c) of the proposed MACT rule references an applicability threshold of 250 MMBtu/hr, with a parenthetical indicating that this heat input is equivalent to 25 MW. Commenters note that, depending on the heat rate of an EGU, it may require more or less than 250 MMBtu to generate 25 MW of electricity. Commenters state that referencing 250 MMBtu/hr as a threshold marker is confusing; 25 MW alone should be used as the applicability threshold in all sections of the rule for consistency and clarity.

Comment 12: Commenter 17733 strongly agrees with the preamble's statement that units that do not meet the efficiency standards required to be a cogeneration unit should still qualify as EGUs if they otherwise meet the definition of an EGU. Otherwise, owners of coal and oil-fired units would be encouraged to avoid the EGU MACT requirements by reducing their units' efficiency. This result would clearly be contrary to the intent of the CAA, and also clearly violate the EPA's Trust Responsibility and its obligations under the Environmental Justice Doctrine. The commenter requests that the EPA should make it clear in the final rule that any unit that does not meet the efficiency requirements of a cogeneration unit will still qualify as an EGU if the unit otherwise meets the CAA EGU definition.

Further, Commenter 17733 strongly disagrees with the EPA's interpretation of the CAA section

112(a)(8) definition “that a non-cogeneration unit must both have a combustion unit of more than 25 MWe and supply more than 25MWe to any utility power distribution system for sale to be considered an EGU pursuant to this proposed rule so as to be consistent with the cogeneration definition in CAA section 112(a)(8).” This interpretation is contrary to the plain language of the first sentence of CAA section 112(a)(8). This sentence makes clear that an EGU includes “any fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.” Nowhere does it indicate that a non-cogeneration unit must supply more than 25 MWe to a utility-power distribution system for sale to be considered an EGU.

Commenter 17733 states that the EPA’s narrowing of the definition of an EGU is especially concerning, since it is likely to exclude from the requirements of the EGU MACT Rule many older, less efficient, and dirtier facilities. Owners of these facilities will likely be incentivized to reduce their electrical output to just below 25 MWe and thereby avoid having to implement more effective Hg controls. This will allow substantially more Hg contamination to occur, and therefore will be inconsistent with the EPA’s Trust Responsibility and the Environmental Justice Doctrine.

Commenter 17733 states that the EPA should make clear that units that fail to qualify as a cogeneration unit will appropriately be considered an EGU if they meet the qualifications in the first sentence of the EGU definition. This would mean that units that do not meet the efficiency standards for a cogeneration unit are considered an EGU if they are a fossil fuel-fired combustion unit of more than 25 MW, that serves a generator that produces electricity for sale (regardless of whether the generator actually supplies more than 25 MWe to a utility power distribution system). By applying this standard, the EPA can ensure that units that do not meet the cogeneration efficiency requirements are appropriately treated like any other fossil fuel-fired unit. This will allow the EPA to help limit Hg emissions and therefore their impact on Native American communities.

Comment 13: Commenter 17648 states that the EPA has scoped the Toxics Rule properly to apply to EGUs that meet the definition of EGU in CAA section 112(a)(8). The affected sources will all be units with original nameplate rate capacity of more than 25 MW, consistent with the statutory definition of EGUs, thus excluding from the rule relatively small units.

Comment 14: Commenter 17775 supports the EPA’s choice of dates for defining a new EGU.

Response to Comments 2 - 14: The EPA’s interpretation of the statutory definition of the source category found in CAA section 112(a)(8) (.”..combustion unit of more than 25 megawatts...”) is that it clearly refers to the size of the combustion unit (i.e., boiler) rather than to the size of the generator. Thus, EPA is not modifying the definition of an EGU such that it relies on the generator size as suggested by some commenters as this would be outside EPA’s authority. We do not interpret the CAA section 112(a)(8) definition to include consideration of the size of the generator for a non-cogeneration combustion unit as long as the combustion unit itself is greater than 25 MW.

As noted by other commenters, boilers by themselves do not generate any electricity. The EPA had, therefore, provided for clarity the general heat input equivalency. However, other commenters indicated that this equivalency would not hold uniformly as a result of differences in boiler efficiency. Further, EPA’s stated intent was to use the “nameplate” capacity of the boiler (i.e., the design capacity expressed on the “nameplate” affixed to the boiler). Absent such a “nameplate,” the boiler size contained in the original permit would serve as the “nameplate capacity.” The EPA has re-evaluated its use of the term “MW” and believes the correct interpretation would be “megawatt-thermal,” or MW_t (thermal power produced by the combustion unit) as opposed to MWe which is the electric power generated by the generator. The EPA has modified the final rule to note only the 25 MW distinction for consistency and clarity rather than the equivalent heat input. Further, EPA interprets the "more than" in the literal sense to mean a combustion unit having a nameplate capacity (either original or modified) of greater than 25 megawatts regardless of its current operating capacity. Any combustion unit with a nameplate capacity of 25 MW or less, regardless of the size of the generator being served, would not be subject to the final rule.

The EPA agrees with the commenter that we erred in providing the "non-cogeneration" definition and have removed it from the final rule. Further, EPA believes that the statutory definition for non-cogeneration units is clear in CAA section 112(a)(8) and in the final rule, EPA adheres to that definition. However, EPA believes that the commenter has misunderstood the provisions of the rule. There are no "efficiency standards required to be a cogeneration unit" included in the proposed or final rule. There is only the requirement contained in CAA section 112(a)(8) that the cogeneration unit supply "more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale..."

The EPA specified in Table 10 of the proposal preamble that the output-based emission limits (i.e., lb/MWh or lb/GWh) are specified as "gross." The EPA has made this clarification in the final rule.

4. Definition of cogeneration facility.

Comment 15: Commenter 19040 questions why the definitions for a cogeneration facility differ in the proposed rule and the Transport rule. The definition in the Transport Rule requires the cogeneration system either be a topping-cycle or bottom-cycle unit and the electric sales onto the grid cannot exceed the greater of one-third the nameplate capacity or 219,000 MWh per year.

Response to Comment 15: The EPA is operating under different statutory provisions for the Cross-State Air Pollution Rule and the Mercury and Air Toxics Standards. We believe that our definitions in each rule are consistent with the relevant statutory authority.

5. Definition of "fossil fuel-fired."

Comment 16: Commenter 17733 supports the EPA's definition of "fossil fuel-fired," which helps ensure that units cannot make short-term operational changes to avoid or delay meeting the requirements of the EGU MACT Rule, consistent with the first sentence of the CAA definition and the EPA's obligations under the Trust Responsibility and the Environmental Justice Doctrine.

Comment 17: Commenter 17805 recommends that the definition of "fossil fuel-fired" should also be revised as follows for consistency:

> "Fossil fuel-fired (or cogeneration means a cogeneration means an electric utility steam generating unit (EGU) that is capable of combusting sufficient fossil fuel more than 73 MWe (250 million Btu/hr, MMBtu/hr) heat input (equivalent to 25 MWe output of fossil fuels to generate 25 MWe from such fuels alone. To be ''capable of combusting' ' fossil fuels, an EGU would need to have these fossil fuels allowed in their permits and have the appropriate fossil fuel handling facilities on-site (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 % of the average annual heat input during the previous 3 calendar years or for more than 15.0 % of

the annual heat input during any one of those calendar years."

Commenter 17880 also recommends this proposed definition of fossil-fuel fired.

Comment 18: Commenter 17796 recommends that the EPA revise the definitions for "fossil fuel" and "fossil fuel-fired steam generating unit" to be consistent with the definitions of subpart D.

Comment 19: Commenter 17818 states that the definition of "fossil fuel-fired" units should be refined to reduce confusion and inconsistencies. The commenter provides several examples where the language uses both MW to convey fossil fuel-fired heat input and to convey MW electric. The commenter suggests that it may be more appropriate to relate MW thermal as fossil fuel-fired heat input rather than MW electric.

Response to Comments 16 - 19: As noted in the preamble to the final rule, the EPA has made some changes to the definition of "fossil fuel-fired" in the final rule; we believe the final definition to be consistent with the statutory definition in CAA section 112(a)(8). In addition, as noted elsewhere, the EPA has clarified its use of the term "MW" and has removed the than 73 MWe (250 million Btu/hr, MMBtu/hr) equivalency term.

Comment 20: Several commenters indicated that the definition of "fossil fuel-fired" did not adequately account for fuel switching and would require permit revisions to eliminate any mention of using coal or oil to produce electricity and the removal of all coal handling equipment, coal storage areas.

Comment 21: Commenters 17756 and 17775 state that the definition of "fossil fuel-fired" EGUs may potentially discourage natural gas and biomass conversions which require "bridging strategies." The EPA views a unit as "capable of combusting" fossil fuels if burning those fuels is allowed in their permits and they have the appropriate fuel handling equipment on site therefore the unit would be subject to the proposed Toxics Rule. The commenter requests that the EPA revise the definition of "fossil fuel-fired" EGUs.

Comment 22: Commenter 18023 requests that the EPA update the definition of "fossil fuel-fired" to adequately account for fuel switching as a potential compliance strategy.

Response to Comments 20 - 22: The EPA does not agree with the commenters and we are not revising that aspect of the definition of "fossil-fuel fired." The EPA does not agree that sources will have to dismantle all their fossil-fuel handling systems *and* revise their Title V permits to prohibit fossil-fuel combustion above a certain threshold, though either approach may be independently sufficient to make a source incapable of combusting sufficient fossil fuel to meet the definition of "fossil-fuel fired." Sources could retain both their fossil-fuel handling facilities and their Title V permit authority as long as the source is not combusting fossil-fuel more than 10.0 % of the average annual heat input during the any three 3 calendar years or for more than 15.0 % of the annual heat input during any one calendar years after the applicable compliance date. The EPA believes the definition provides flexibility for sources while simultaneously preventing sources from improperly avoiding regulation. EGUs that want to use fuel switching as a compliance strategy should include in their Title V permit provisions that preclude being coal- or oil-fired EGUs.

Comment 23: Commenters 18023 and 17775 state that the "look-back" period may potentially penalize a unit that retains capability to combust fuels other than natural gas and units that previously burned coal or oil. Commenter 18023 recommends that the EPA should eliminate the "look-back" period and define an affected unit by whether it actually has heat input exceeding the stated thresholds. A unit that, beginning on the effective date, fires less than 15 % coal or oil on an annual basis (and less than 10 % on a triennial basis) would not be considered "fossil fuel-fired" and would not be considered an affected facility. Under this scenario, a unit that switches to natural gas and retains its capability to combust coal or oil would not be penalized for burning coal or oil during the time period before the effective date.

Comment 24: Commenter 17775 recommends that the EPA should revise the definition to change the "look-back" period to begin 3 years after the unit's final compliance date so that it does not penalize a unit for having burned coal or oil in the period before compliance or for switching to natural gas but retaining the ability to combust coal or oil (a desirable outcome to provide system reliability). The commenter further states that unit owners would need to convert the unit to 100 % biomass or natural gas within 3 years and remove all capability to burn coal or oil in order be exempt from the EGU MACT rule. Alternatively, the unit could convert to biomass or natural gas by 2012 and ensure that the heat input from coal or oil in 2012, 2013 and 2014 is below the annual 15 % heat input requirement and the 3-year requirement of 10 % heat input. Commenter 17775 also requests that the EPA clarify that a unit that switches to natural gas and later switches back to highly controlled coal use would not be in violation of the 3-year average for the years it was burning natural gas.

Response to Comments 23 and 24: As noted preamble to the final rule, the EPA has made changes to the definition of "fossil fuel-fired" which we believe will address this comment. Further, a Title V permit modification that prohibits the combustion of coal or oil would make the source incapable of legally burning such fuels and would be sufficient to satisfy the requirements of the final rule.

6. Definition of "oil-fired electric steam generating unit."

Comment 25: Commenter 17805 recommends that the definition of "oil fired electric steam generating unit" should be revised as follows for consistency:

> "Oil-fired electric utility steam generating unit means an electric utility steam generating unit that either burns oil exclusively, or burns oil alternately with burning fuels other than oil at other times. In addition, oil-fired means any EGU that fired oil (or more than 10.0 % of the average annual/teat input during the previous 3 calendar years or (or more than 15.0 % of the annual/teat input during any one of those calendar years."

Comment 26: Commenter18024 submits that the EGU MACT Rule should exclude the fuel input associated with complying with state reliability requirements from the heat input calculation for the liquid oil-fired unit subcategory. Commenter requests that the EPA add the following language to the proposed definition of "units" designed to burn liquid oil fuel:

> "Units designed to burn liquid oil fuel subcategory includes any EGU that burned any liquid oil for more than 10.0 % of the average annual heat input during the previous three calendar years or for more than 15.0 % of the annual heat input during any one of those calendar years, either alone or in combination with gaseous fuels, provided, however, that liquid oil burned during the three calendar year period to meet state reliability requirements shall be excluded from the heat input calculation."

Alternatively, Commenter18024 would support changing the applicability definition for "units" designed to burn liquid oil fuel from > 10 %/15 % of actual heat input to >30 % of actual heat input (3-year rolling average). Based on historical operation, the commenter believes that 30 % oil firing at a facility would be sufficient to provide needed reliability in conformance with the State reliability rules.

Comment 27: Commenter 17725 notes that the definition for "oil-fired EGU" may have the unintended consequence of excluding some units using emissions averaging. The proposed regulations state that emissions averaging can only be used for units within the same subcategory at the same location, and under the common control of the same person. But, as the fuel use of the dual-fueled units is managed at the site to meet the requirements of averaging, there is the risk that an individual dual-fueled EGU at the site may use more than 85-90 % natural gas, and therefore may no longer meet the definition of "oil-fired EGU." If a unit does not meet the definition of "oil-fired EGU" then, it is ineligible to be used in the averaging strategy.

Response to Comments 25 - 27: As stated in the preamble to the final rule, the EPA is establishing a limited-use liquid oil-fired EGU subcategory and sources in the subcategory will be required to comply with work practice standards. See the preamble for specific responses to the comments.

7. Definition of "coal-fired electric utility steam generating unit."

Comment 28: Commenter 17805 recommends that the definitions of "coal-fired electric utility steam generating unit" should be revised as follows for consistency:

> "Coal-fired electric utility steam generating unit" means an electric utility steam generating unit meeting the definition of "fossil fuel fired" that burns coal or coal refuse either exclusively, in any combination together, or in any combination with other fuels in any amount. In addition, coal-fired means any EGU that fired coal for more than 10.0 % of the average annual/teat input during the previous 3 calendar years or for more than 15.0 % of the annual/heat input during any one of those calendar years.

Comment 29: Commenter 17623 requests that the EPA update the definitions to clearly state that the emissions standards applicable to coal-fired units also apply to any EGU using any amount of coal or coal refuse, whether blended with other fuels or burning both coal and petcoke. The commenter states that although the preamble contains the appropriate language, the definitions for each subcategory could be interpreted differently if read separate from the preamble. The commenter recommends that the final rule clearly specifies that the standards for coal-fired units apply in cases where an EGU is burning coal or any combination of coal and another fuel.

Response to Comments 28 - 29: As stated in the preamble to the final rule, the EPA is revising the definition of "coal-fired electric utility steam generating unit." We believe this is appropriate to be consistent with the definition of "fossil-fuel fired." We are making a similar change to the definition of "oil-fired" EGU and adding a definition for "natural gas-fired" EGU. We think these definitional changes provide clarity to the approach we proposed. In addition, EPA has revised the definitions to make clear that a unit is not an oil-fired EGU if it meets the definition of "coal-fired EGU."

Comment 30: Commenter 17868 disagrees with the EPA's decision not to include petcoke in the coal subcategory and urges EPA to review UARG's comments on the subject.

Comment 31: Commenters 17623 and 18034 recommend that the coal subcategorization definitions should be reviewed and revised for clarity.

Comment 32: Because the EPA chose not to subcategorize based on coal rank or liquid fuel type (i.e., No. 2/ No. 6), Commenter 17881 believes that fuel type should correspond to the subcategory definition. As long as the emission limits are being met for the applicable subcategory, the blend of bituminous/sub-bituminous or other solid fuel should not matter. The same can be said for different ranks of liquid fuels. Ultimately, compliance is based on the subcategory definition, not on fuel types, and the onus is on the facility to demonstrate compliance.

Response to Comments 30 - 32: The EPA generally agrees with the commenters' characterization of a sources responsibility to assure its compliance with the final rule. The EPA has revised the definitions in the final rule in a manner that we believe provides added clarity. As petroleum coke (pet coke) is derived from liquid oil rather than coal, we believe it appropriate to maintain it as a subcategory of oil.

Comment 33: Commenter18034 suggests that the coal subcategorization definitions be based solely on fuel heat content design criteria. Alternatively, the EPA should provide a definition of height-to-depth ratio to avoid misinterpretation regarding applicability of coal units since some investigators not have the necessary information to verify the proper categorization of a unit. The commenter further suggests that may create an inadvertent loop-hole in the rule if a unit is designed to burn coal with heat content greater than 8,300 Btu/lb and a height-to-depth ration greater than 3.82, and therefore would not be subject to the emission limits.

Comment 34: Commenter 17914 states that it is the fuel properties that impact the potential Hg emissions rate and submits that they have designed and supplied boilers to burn similar low-rank coals with lower height-to-depth ratios than the proposed ratio cut-off of 3.82 in the U.S. EGU market. The commenter believes the ratio was determined directly from Figure 19 of Chapter 20 in, "Steam/its generation and use," 40th Edition but states that the dimensions are illustrative only and do not reflect a firm design criteria. The commenter respectfully questions the significance of the boiler dimensional criterion as a condition for establishing the Hg emissions limit for an existing EGU and states that an arbitrary limit on HID may actually prohibit a designer from reaching the most optimized combustion system and furnace design for new EGUs. Like commenter 18034-A3, Commenter 17914 requests that the EPA consider using the noted fuel characteristic as the sole criteria for defining the appropriate Hg emissions limit.

Comment 35: Commenter 17846 states that the definition "burn lignite coal" provides too much flexibility for EGUs to switch categories by simply changing their fuel source and does not make clear that the 3.82 height to depth ratio applies to the EGU furnace and not the EGU as a whole. The commenter requests that the EPA revise the rule's definition to limit the subcategory to "any EGU designed to burn *only* [lignite coal] in an EGU with a height-to-depth ratio of 3.82 or greater."

Response to Comments 33 - 35: The EPA does not believe it appropriate to base the subcategorization solely on the fuel heat content. However, the EPA has revised the definition of the subcategory to more adequately define the subcategory without precluding fuel blending. The EPA does not believe that units designed to burn this low rank virgin coal will be constructed outside the area where the coal is found because of the unique considerations that are involved; proximity to the mine has been included in the definition.

8. Definition of "coal refuse."

Comment 36: Multiple commenters (17754, 17855, 17812, 17838, 18963, 17804) recommend that the definition of coal refuse be reviewed and updated to account for the documented and inherent variability of the fuel source. The commenters note that the definition of "coal refuse" in the proposed rule contains additional qualifying language that requires material to exhibit "ash content greater than 50 % (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis to be defined as coal refuse." Therefore, much of the coal refuse combusted would not meet the applicable definition because it would not satisfy the applicable ash content and heating value criteria. The commenters requests that the EPA revise the definition of "coal refuse" under the proposed rule by eliminating the restrictions on heating value and ash content to account for the variability and be consistent other federal regulatory language.

Comment 37: Commenter 17855 states that the definitions do not seem to incorporate waste-coal power plants as affected facilities, although we believe it is the EPA's intent that these plants be regulated as EGUs under this rule. Similarly, Commenters 17754, 17838 and 18963 question how a unit combusting coal refuse that does not satisfy the definitions under the proposed rule of either coal refuse or coal would be classified, and whether it would therefore effectively avoiding regulation under the proposed rule altogether. The commenters further state that the heating value and ash content within the proposed definition of "coal refuse" are inconsistent with the EPA's clear recognition in the preamble to the proposed rule of the environmental benefits associated with the combustion of coal refuse.

Comment 38: Commenter-17812 states that waste-coal plants that are classified as Qualifying Facilities either as Independent Power Production Facilities or Cogeneration Facilities burning waste-coal had their fuel supply certified by FERC. The commenter refers to the preamble and its reference to the NHSM rule that currently-mined coal refuse should not be considered a solid waste under the Resource Conservation and Recovery Act (RCRA), as long as it is not discarded. The NHSM rule further states that the coal refuse would be subject to the Utility MACT regulation, if the unit meets the definition of EGU. The commenter indicates that the definition of coal refuse should be revised so that coal refuse can be subject to the Utility MACT regulations, consistent with the language of the NHSM rule.

Comment 39: Commenter 17880 states that if a unit combusts coal by-products, it should be subject to regulation under CAA section 129 – Solid Waste Combustion Rule. In February of 2011, the EPA determined that unless processed coal refuse is discarded, it cannot be considered solid waste under the Non-Hazardous Solid Waste Definition Rule.

Response to Comments 36 - 39: The EPA has revised the definition of "coal refuse" to be consistent with the definition found in 40 CFR subpart Da. The EPA believes that the definition of "Coal-fired electric utility steam generating unit" already clearly states that coal refuse is a covered fuel. Units burning coal refuse and not meeting the definition of an EGU in the final rule would likely be subject to the Industrial Boiler NESHAP (40 CFR Part 63, subpart DDDDD).

Certification of a fuel by FERC or any other body does not supersede the appropriate definitions applicable to CAA section 112. EGUs burning a coal refuse meeting the definition of a "solid waste" under the NHSM rule would be subject to standards issued pursuant the CAA section 129 (e.g., the final CISWI rule); however, we did not identify in the proposed rule any EGUs that are burning coal refuse that is a solid waste. Furthermore, no units indicated in comments that they are burning coal refuse that is a solid waste so all units that meet the definition of EGU and combust coal refuse are subject to this final rule.

9. Definition of fossil fuel.

Comment 40: Commenter 18427 requests that the EPA revise the definition of "fossil fuel" in the proposed Utility MACT as follows:

> "Fossil fuel means natural gas, oil, coal and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat."

The commenter states that there is no justifiable basis to define the term "fossil fuel" meaningfully differently under the two relevant regulatory programs, both of which apply to fossil fuel-fired electric utility steam generating units. Further, revising the definition of fossil fuel under the proposed Utility MACT in this manner will ensure consistent application of the applicable regulatory standards to these units.

Further, the commenter requests that the EPA clarify within subpart Da and the proposed Utility MACT 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. The commenter believes that the EPA has not intended to include landfill gas or other biogases within the definition of "fossil fuel," but states that there is some ambiguity presented by the definitions included in the proposed rules as drafted because both the proposed Utility MACT and the proposed revision to subpart Da define and use the term "gaseous fuel" (which is contained within the definition of "fossil fuel") to encompass a broader category of fuels than fossil fuels.

The commenter also requests:

- EPA clarify in the context of the proposed rules that neither subpart Da nor the proposed Utility MACT would apply to a unit which exclusively or primarily combusts a "gaseous fuel" that is not otherwise a fossil fuel.
- EPA clarify the circumstances under which a non-fossil gaseous fuel-fired unit may be affected by the proposed rules.
- To the extent that use of a non-fossil gaseous fuel may be covered under subpart Da or the proposed Utility MACT under certain circumstances, the proposed rules should be clear with respect to the manner in which such non-fossil gaseous fuels may be affected.

Response to Comment 40: Some fossil fuels in current use at EGUs (e.g., petroleum coke) were not derived for the purpose of creating useful heat. Therefore, including this phrase in the definition as commenter suggests would preclude coverage of an EGU burning pet coke under the final rule unless the unit blended the pet coke with coal such that the unit met the definition of "coal-fired electric utility steam generating unit." The EPA recognizes that there may be differences in the definition of "fossil fuel" among the different regulatory actions, but we have determined that byproducts of fossil fuels should be regulated for HAP in the same manner as raw fossil fuels because the fuel-borne HAP content is the same as the raw fuel, regardless of whether there was an intent to create the byproduct for the purpose of creating useful heat. For example, pet coke contains the same fuel borne HAP as the raw fossil fuel from which it is derived (i.e., oil). In addition, although pet coke is a byproduct of oil refining, it is also currently recognized as a valuable fuel commodity, which was not the case when the 40 CFR Part 60, subpart Da definition was promulgated. For these reasons, we are retaining the proposed definition.

The EPA believes that the definitions are sufficiently clear that only fossil fuels, or fuels derived from fossil fuels, are covered under the final rule. Materials noted by the commenter (e.g., landfill gas, biogases, materials derived from municipal solid waste) are, in EPA's opinion, clearly not derived from "fossil fuel" and, thus, not covered under the final rule. "Gaseous fuel" in the definition of "fossil fuel" is clearly linked to fossil fuels through the "derived from" phrase. The EPA does not believe that there is any confusion in the definition.

10. Definitions of miscellaneous terms.

Comment 41: Several commenters note inconsistent definitions for operating limits. Commenters 17716 and 18498 state that the PM operating limit is defined in section 63.10011(d) as "the average of the PM filterable results" of the three Method 5 performance tests runs and as "at or below the highest 1-hour average" measured during the most recent performance test in Table 4. The commenters suggest that the inconsistency should be eliminated by using a filterable PM (FPM) limit as a surrogate for non-Hg metal HAP instead of total PM (TPM). However, if a PM operating limit is used, the inconsistency between sections should be reviewed and corrected.

Response to Comment 41: The comment is moot because rule now allows compliance with filterable, not total, particulate matter (PM).

Comment 42: Commenter 17800 states that the EPA provides four inconsistent definitions for minimum control device operating parameters in:

- the preamble ("The average of the three minimum (or maximum) values from the three runs for each applicable parameter would establish a site-specific operating limit."(FR Vol. 76, No. 85, p. 25,029));
- Section § 63.10042 ("90 %" of the "test average" during the most recent performance test);
- Table 4 ("at or above the lowest 1-hour average"); and
- Table 8 ("12-hour block average" "at or above" the operating limit established under § 63.10011(c)).

The commenter recommends that the EPA adopt the "90 %" criterion and the 12-hour-block average to provide some level of flexibility to account for changes in unit operation. Furthermore, the commenter requests that the EPA provide data to support achievability or enforceability of operating parameters under the final definition.

Response to Comment 42: This comment is moot because rule no longer requires parameter monitoring or operational limits for pollution control devices.

Comment 43: Commenter 18444 supports limiting emissions of total filterable and total condensable PM and therefore recommends that the PM definition in the proposed rules include the sum of the total filterable and total condensables.

Response to Comment 43: As explained elsewhere, the rule now uses filterable PM as an indicator of non-Hg metals since filterable PM, total PM and total $PM_{2.5}$ provided comparable correlations with the metals emissions. As a result, the comment requesting a definition clarifying that total PM emissions is the sum of the condensable and filterable PM is moot.

Comment 44: Commenter 18023 requests that the EPA revise the definition of an operating day to be consistent with the NSPS. Specifically, the commenter suggests that the definition of an operating day's worth of data in section 5.2. 1, Sorbent Trap Monitoring Systems, should include no less than 18 hours of valid data rather than only 15 minutes.

Response to Comment 44: The commenter's suggestion to establish a minimum data collection period that would constitute a boiler operating day is inconsistent with the Agency's view that data collection, as well as emissions control device operation, needs to occur during each period of unit operation, regardless of the duration. The rule maintains requirements to operate the monitoring system and collect data at all required intervals at all times that the affected unit is operating, except for periods of monitoring system malfunctions or out-of-control periods and periods of monitoring quality checks, and to use all data collected outside these periods in assessing continuous compliance.

Comment 45: Commenter 17681 requests that the EPA clarify the definition of a "30 Operating Day Rolling Average" as well as the methods used to calculate the average. Commenter requests that the EPA clarify that a 30-operating day is based on the average of all applicable hours in the 30-day period.

Response to Comment 45: The agency is unsure of the commenter's clarification request, as a 30 boiler operating day rolling average is the average of all the hourly values calculated over 30 previous, consecutive boiler operating days. The equation is as follows:

$$30\ boiler\ operating\ day\ rolling\ average\ = \frac{1}{30}\sum_{k=1}^{30} hourly\ average_k$$

where k = individual hourly average over previous 30 days on which fuel was combusted.

The rule contains a definition of boiler operating day in section 63.10042 and the equation in section 63.10021(b)(3).

Comment 46: Commenter 17721 requests that the EPA revise the definition of "minimum sorbent injection rate" on page 25123 of the proposed rule as follows:

> "Minimum Sorbent Injection or Addition Rate means 90 % of the test average sorbent injection or addition rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits."

Response to Comment 46: This comment is moot because rule no longer requires monitoring of the sorbent injection rate.

Comment 47: Commenters 17801 and 17821 recommend that the EPA modify the proposed definition (p. 25123) of gross output 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 **(including IGCC),** the gross useful work performed is the gross electrical output from the unit's turbine/generator sets **(including steam turbines)**. For a cogeneration unit, the gross useful work performed is the gross electrical, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site emission controls), or mechanical output plus 75% 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)."

Response to Comment 47: The EPA has modified the definition in the final rule 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, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 % 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 48: Commenters 17801and 17821 recommend modifying the definition of Heat Input (p. 25,123) as follows: "Heat Input means heat derived from combustion of fuel in an EGU (synthetic gas to the combustion turbine for IGCC) and does not include the heat input from…" This will help avoid any confusion or inconsistent application of using coal in lieu of syngas as the basis for any values based on heat input.

Response to Comment 48: The EPA has modified the definition in the final rule as follows:

> <u>Heat input</u> means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Comment 49: Commenter 17821 supports the rule's proposed definition for fuel type, specifically agreeing that receiving fuel from different suppliers does not constitute a change in fuel type.

Response to Comment 49: The EPA appreciates the commenter's support. The EPA has made revisions to certain definitions as discussed elsewhere to provide clarity in the final rule.

Comment 50: Commenter17402 suggests that the EPA's definition of "deviation" is too broad and results in excessive infeasible reporting requirements. The commenter recommends that operating limits and monitoring requirements should not be included in the definition. Additionally, the commenter recommends that any notification of exceedances should be reported in semiannual compliance reports rather than the current proposed notification schedule.

Response to Comment 50: Even though the agency disagrees with the commenter's view, a rule change to drop almost all operating limits and control device parameter monitoring in favor of frequent emissions testing or continuous monitoring should alleviate the commenter's concerns. The proposed notification schedule for deviations from operating limits established by unit owners or operators by choice for non-mercury metals monitoring and for fuel oil moisture monitoring for hydrogen halides will remain. The EPA has modified the definition of "deviation" in the final rule as follows:

> Deviation.
> (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:
> (i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or
> (ii) Fails to meet any term or condition that is adopted to implement an applicable

requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.
(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Comment 51: Commenter 17838 states that the definition of FGD creates confusion because the first sentence of the definition appears to state that any dry FGD technology shall require an "add-on air pollution control system located downstream of the steam generating unit." In order to avoid the potential inconsistency between these two sentences of the definition, the Commenter recommends that the EPA revise the definition of FGD to expressly state in the second sentence that the sorbent injection system in a CFB boiler need not be a separate add-on air pollution control system located downstream of the steam generating unit.

Response to Comment 51: We believe that the last sentence of the definition ("Sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.") clearly indicate that the Agency considers CFB to be a "dry flue gas desulfurization technology." However, we have made a minor edit to the definition to indicate that alkaline sorbent must be used in CFB units to qualify.

Comment 52: Commenter 17771 requests that the EPA revise the language defining the work practice standard requirement to "optimize combustion" to avoid a situation where facilities might be required to completely shut down operations every 12 to 18 months in order to achieve compliance.

Response to Comment 52: Although the rule does not define the work practice standard requirement to "optimize combustion," the final rule increases the time between burner inspections to 36 months and to 48 months for EGUs that employ neural net technology. This lengthening of time better coincides with routine boiler inspections and should alleviate the commenter's concerns over frequent, premature shutdowns.

Comment 53: Commenter 17655 states that the rule does not clearly define the term "optimize" with respect to the work practice standard for organic HAPS. Section 63.10021(a)(16)(iv) includes a subjective requirement to "optimize" total emissions of CO and NO_X per manufacturer's specifications, but the commenter argues that the term needs to be defined so that it is not interpreted as "minimized" or "balanced" by future facilities seeking compliance. The commenter suggests that an operational definition should aim to yield reduced CO levels and comply with applicable NO_X limits throughout the normal range of operation and suggests that manufacturers' recommendations, if available, could be of considerable assistance in developing the definition.

Response to Comment 53: The EPA recognizes the economic drivers behind optimal combustion of fuel to maximize output while minimizing fuel costs, and the EPA recognizes the nuances of managing NO_X emission limits with these optimization efforts. Rather than drive tuning toward "minimal NO_X" or "minimal CO" thresholds, we have developed language requiring tuning to conform with "best combustion engineering practice" for each burner type affected. We expect owners or operators of EGUs to maintain the balance of optimal combustion with NO_X control and use sound combustion engineering practice to maintain that balance. In the final rule we have also added incentives for units that employ neural net combustion optimization systems during hours of normal operation.

Comment 54: Commenter 17728 indicates that the definitions for major and area sources are inconsistent within section 112(a). The section defines major and area sources as any “stationary source located within a contiguous area and under common control.” The section also declares that the “stationary source” term is defined in CAA section 111(a), stating that “any building, structure, facility, or installation which emits or may emit any air pollutant.”

Response to Comment 54: The EPA did not provide definitions for “major source” or “area source” within the final preamble. Instead, EPA relies on the definitions as they appear in CAA section 112.

8B - Rule: Definitions (new)

Commenters: 17655, 17696, 17711, 17718, 17721, 17725, 17755, 17760, 17800, 17808, 17878, 17881, 18025

Comment 1: Several commenters (17760, 17718, 17808, 18025) recommend new definitions with regard to oil-fired units to ensure that applicability is capacity-based. Commenter 17760 and 17718 state that the EPA should adopt the term "oil-affected units" to address oil-fired and oil- and gas-fired units that have low capacity factors on oil fuel usage. In the proposed rule, the definition determines whether a unit that combusts oil is an affected unit based on the percentage of oil combusted by the unit compared to its total heat input. Because the exclusion is based on a fuel combustion ratio, a unit that operates for only two days (one on oil, one on gas) could be subject to the proposed rule, and a unit that combusts the same quantity of oil as the first unit but operates for multiple days on gas to be excluded. Such an arbitrary result is possible given the current operating practices for oil and oil/gas units. Since the promulgation of the Acid Rain Program regulations in 1993, the operation of oil- and oil/gas-fired units has changed significantly. A large fraction of these units are no longer base load units, and typically operate at capacity factors well below 50 %. In many cases, the capacity factor is less than 15 %. The EIA Annual Energy Outlook 2011 forecasts that the amount of liquid fuels used for electricity generation in 2015 will be approximately 60 % lower than 2000 levels.

The commenters suggest that the EPA define an oil-affected unit (an oil-fired unit that is subject to the EGU MACT rule) as:

> "A unit that had a three-year average oil heat input greater than 10 % of the maximum potential annual heat input, calculated by multiplying the maximum design heat input by 8760. This definition would ensure that the EGU MACT rule targets EGUs with greater HAP emissions from the combustion of oil, and address EPA's concerns regarding limited use oil-fired units, which typically operate at very low capacity factors."

Response to Comment 1: As noted elsewhere, the EPA has modified the definition of "oil-fired" EGU. A discussion of the limited use issue is provided elsewhere in the final rule record.

Comment 2: Commenters 17808 and 18025 request that the EPA adopt a definition for a limited-use oil-fired EGU, which is any boiler that burns any amount of liquid oil, has a rated capacity of greater than 25 MW, and has an annual average capacity factor based on its oil use of 10.0 % or less over the past 3 years (and not more than 20.0 % in each of those 3 years). The commenters recommend this definition it reflects the varying loads of an EGU and is precedented in Part 75. The commenters also suggest that that "capacity factor" is the ratio of the unit's actual annual oil heat input to the unit's maximum design heat input times 8,760.

Response to Comment 2: A discussion of the limited use issue is provided elsewhere in this document.

Comment 3: Commenter 17725 proposes that the EPA adopt a new definition, "Oil-fired facility for site averaging," to account for the event that a site meets its emissions limits but may have individual dual-fired units which do not meet the oil-fired EGU definition. Currently, the source owner may be forced to operate the EGU on oil just to maintain the EGU's oil-fired status and eligibility for inclusion in the averaging calculation, resulting in additional emissions with no compliance benefits. In fact, based on the amount of oil-firing needed, the site's emissions average may increase to the point where site-wide compliance is not attained. The commenter recommends a definition based on the total average oil-fired heat input for all EGUs within the site averaging plan as follows:

> "For purposes of site averaging, the subcategorization for individual EGUs shall be based on the EGU's operation prior to the effective date of the regulations. Upon the effective date of the regulations, subcategorization shall be based on the total oil-fired heat input divided by the total heat input from all fuels from the affected EGUs An Oil-fired facility shall have an average annual heat input on oil more than 10.0% for the 3 calendar years prior to the effective date of the regulations or more than 15.0 % for any single year within the three-year period."

The commenter states that this definition encourages the use of lower emitting fuels through emission averaging but does not limit compliance options or require mandatory oil-firing to maintain an EGU's oil-fired status.

Response to Comment 3: As noted elsewhere, the EPA has modified the definition of "oil-fired" EGU. Discussions of the limited use and site averaging issues are provided elsewhere in this document.

Comment 4: Commenter17800 recommends that the EPA provides definitions for certified Flow, CO_2, or O_2 monitoring systems, with respect to appendix A, subpart UUUUU. The commenter inquires as to whether the certification refers to CFR Part 75 or Part 60.

Response to Comment 4: In the final rule, section 3.2.3 of Appendix A explicitly states that the certified flow rate, diluent gas, and moisture monitoring systems that are used to convert Hg concentrations to units of the standard must be installed, certified, operated, maintained, and quality-assured according to 40 CFR Part 75. This is reinforced by §§63.10010(b) through (d).

Comment 5: Commenter 17715 recommends that the EPA use the part 72 definitions for CO_2 and flow range determination and the definition for zero gas to provide an accurate definition which harmonizes the definitions across more than one rule.

Response to Comment 5: The agency agrees with the commenter, and, as part of its review to reduce burden and costs, decided to better integrate MATS monitoring requirements with those of the Acid Rain program. As a result, and as mentioned elsewhere, the rule builds off the Acid Rain program requirements whenever possible.

Comment 6: Commenter 17711 requests that the EPA add a definition for fuel cell to avoid any misinterpretations. Although the commenter believes the steam generating unit language is intended to address integrated gasification fuel cells, the wood products industry commonly uses the term fuel cells to refer to biomass combustion devices.

Response to Comment 6: Fuel cells as noted by commenter would not be EGUs under the final rule as they are biomass-fired and, thus, not fossil fuel-fired.

Comment 7: Commenter 17721 proposes that the EPA add the following definition of DLPS to section 63.10042 of subpart UUUUU of the proposed rule (page 25121):

> "Dual liquid powder sorbent injection (DLPS) is an Hg-control technology where a liquid sorbent is added onto the coal before combustion and a powder sorbent is mixed with the coal, injected into the furnace, or is duct injected. The liquid sorbent is a water solution of

a bromine compound, while the powder sorbent is an alkaline powder containing calcium and significant levels of aluminosilicates."

The commenter further suggests that the following language be added to the proposed rule to expressly authorize or at least recognize DLPS systems as available emissions control technology:

- (at the fourth-to-last sentence in section III.D.6.c, which appears on page 25014 of the proposed rule) "Hydrogen chloride and HF have also been shown to be effectively removed using DSI where a dry, alkaline sorbent (e.g., hydrated lime, trona, sodium carbonate) is injected upstream of a PM control device, or when powder sorbents such as those used in a dual liquid-powder sorbent system are combined with coal or injected into the fireball of the furnace."
- (at the second-to-last paragraph in section III.D.6.c, which appears on page 25014 of the proposed rule) "The use of halogen additives in combination with powders containing calcium and aluminosilicates leads to significant reduction of SO_2 as well as nearly complete control of emitted Hg. A dual liquid-powder sorbent ("DLPS") system consists of adding an aqueous solution of a halogen, especially a bromine compound, onto the coal upstream of the furnace. Then a powder sorbent containing calcium and aluminosilicates is injected into the furnace during combustion of the halogen-containing coal. With some fuels, adequate Hg control is achieved with only the powder sorbent. Whether halogen is added or not, the use of the powder sorbent results in capture of the Hg and other HAP metals in a microencapsulated non-leaching form in the ceramic matrix of the coal ash remaining from combustion. Such methods are in commercial use and perform well with high sulfur coals, as it provides for sulfur removal as well. An additional advantage is that the Hg and other HAP metals are bound tightly in the fly ash so that they do not leach from the ash during storage or reuse, including during reuse in concrete."
- (after the sentence beginning "Activated carbon injection is the most successfully demonstrated Hg-specific control technology," in section D.8.c, which appears on page 25017 of the proposed rule) "On the other hand, the effectiveness of the dual liquid-powder sorbent ("DLPS") system for controlling SO_2, Hg, and other HAP metal emissions may not be compromised by the sulfur content of the coal."

Commenter 17721 also suggests that the following language be added to the rule:

- (following sentence in section III.E, which appears on page 25023 of the proposed rule) "Hydrogen chloride also has a large acid dissociation constant (i.e., HCl is a strong acid) and it, thus, will react easily in an acid-base reaction with caustic sorbents (e.g., lime, limestone), including the powder sorbent containing calcium and aluminosilicates used in the Chem-Mod DLPS system."
- (at the first sentence in section IV.I.(6)(3), which appears on page 25030 of the proposed rule) "For units with dry scrubbers, DSI (including ACI), or DLPS, you would be required to measure the sorbent injection or addition rate for each sorbent used during the performance tests for HCl and Hg and determine the minimum hourly rate of injected sorbent for each test run."
- (at the last sentence in section IV.J.1.(3), which appears on page 25031 of the proposed rule) "For units with dry scrubbers, DSI systems, or DLPS systems we are proposing that you continuously monitor the sorbent injection or addition rate and maintain it at or above the operating limits established during the performance tests."
- (following sentence in section V.K., which appears on page 25052 of the proposed rule) "These parameters include pH, pressure drop and liquid flow rate for wet scrubbers; and sorbent injection or addition rate for dry scrubbers, DSI systems, and DLPS systems."

- (following sentence in section V.M., which appears on page 25054 of the proposed rule) "This includes technologies to control acid gases (wet and dry scrubber technology and the use of sorbent injection), the Hg requirements (co-benefits from other controls such as scrubbers and FFs and Hg-specific controls such as ACI and DLPS), the non-Hg metal requirements (upgrades and or replacements of existing particulate control devices), and other HAP emissions (GCP)."
- (following sentence in section V.M., which appears on page 25054 of the proposed rule) "For Hg, EPA projects that companies will comply through the collateral reductions created by other controls (e.g., scrubber/SCR combination), ACI, or DLPS technology."
- (In section 63.10011(b)(6)(iv), which appears on page 25114 of the proposed rule) "For a dry scrubber, dry sorbent injection (DSI) system, or dual liquid-powder sorbent (DLPS) system, you must establish the minimum hourly average sorbent injection or addition rate for each sorbent, as measured during the three-run performance test and as defined in §63.10042, as your operating limit."
- (In section 63.10022(a)(4), which appears on page 25118 of the proposed rule) "For each existing unit participating in the emissions averaging option that is equipped with dry sorbent injection or dual liquid-powder sorbent injection, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test;"

Response to Comment 7: The agency reviewed the changes suggested by the commenter, and, apart from adding "or other sorbent injection system" to the description of dry sorbent injection, did not make other changes. The Agency notes that the process described by the commenter has been addressed already in the preamble.

Comment 8: Commenter 17755 suggests that the EPA provide a definition of "operating" with regard to section 63.10020(b), which states that the CEMS must operate at all times that the affected EGU is operating. The commenter recommends that the definition should clarify whether operating will include times when the unit is combusting fuel, or only include times when the unit is producing electricity, or if operating includes when the boiler fans are being operated (i.e., ID and FD fans), and will it include startup, shutdown, malfunction, maintenance, and/or offline periods.

Response to Comment 8: The comment is moot because rule's definition of the term *boiler operating day* already describes operation as being the period when fuel is combusted at any time.

Comment 9: Commenter 17696 requests that the EPA create an explicit definition for the "maximum normal operating load" at which performance tests would be required to be conducted under 63.10007(c). The commenter suggests that defining the term will minimize variations in implementation and recommends that the term be defined as"90-100 % of the unit's reported maximum load as identified in EPA's Emissions Collection and Monitoring Plan System (ECMPS) or EIA-767."

Comment 10: Commenter 17881 notes that the term "normal load" is not defined in either Part 63 subpart UUUUU or its associated appendix A. For purposes of defining normal load at which the RATA should be operated, the commenter recommends that the provisions of 40 CFR Part 75, appendix A, section 6.5.2.1 should be adopted in order to eliminate any potential confusion and provide needed flexibility for infrequently operated units (i.e., peaking units), in which case the normal operating load may vary widely.

Response to Comments 9 - 10: The agency reviewed the commenters' concerns, and the rule has been revised so that for purposes of this rule a normal load shall have the meaning given in section 6.5.2.1 of appendix A to Part 75.

Comment 11: Commenter 17881 recommends that the EPA develop a definition for "long-term cold storage" to clarify the EPA's intent on reporting for those units placed into long tern cold storage (LTCS). The commenter states that if the EPA intends to allow discontinuation, similar to the associated provisions in 40 CFR Part 75, the proposed appendix A should also be revised to include relevant supporting infrastructure (i.e., a definition for LTCS, provisions in subpart UUUUU to clarify the reporting obligation for such units etc.).

Response to Comment 11: The rule has not been changed because agency finds the comment not relevant, since an inoperable EGU would have no emissions to report.

Comment 12: Commenter 17878 recommends that ambiguities regarding measurement of "Btus" should be resolved by explicitly defining "British thermal unit" or "Btu" as the gross calorific value (i.e., the higher heating value). This will eliminate the possibility of confusion with the net calorific value (i.e., the lower heating value). Disputes and misunderstandings may result if it is unclear to which basis, gross or net calorific value, the rule refers.

Response to Comment 12: The agency disagrees with the commenter's assertion that the rule is ambiguous, for the Agency and its rules have consistently used the higher heating value, i.e., the gross calorific value, in association with a British thermal unit (Btu). No changes to the rule have been made.

8C - Rule: Corrections to tables

Commenters: 17174, 17191, 17197, 17675, 17677, 17691, 17716, 17718, 17721, 17725, 17775, 17800, 17801, 17808, 17821, 17881, 17886, 17909, 17913, 17915, 18034, 18498, 18539

Comment 1: Several commenters request that the EPA look at inconsistencies within the tables contained in the proposed rule. Most of the comments pertained to specific tables, however Commenter 17677 states that the tables are confusing because they appear to be summarizing too much information in one table and are not pollutant category oriented, e.g., Dioxin/Furans, Non-Hg Metals, Mercury, Acid Gases. The commenter suggests that clarity may be achieved by creating more tables and separating by fuel types as most all facilities will be ≥ 8,300 Btu/lb, then by unit types under each fuel section, then by the pollutant groups. The commenter recommends that the EPA expand the last column "Using these requirements as appropriate" to include specifics rather than statements which may be too general to provide clarity. Additionally, listing a reference method for each test and then including the exceptions to that reference method, as done in some rows, is recommended.

Response to Comment 1: The agency reviewed the concerns of this commenter, as well as other commenters, and the rule tables have been revised for clarity.

Specific comments to tables have been organized by Table, below.

1. Table 1:

Comment 2: Commenter17174 recommends that Table 1 should state that total particulate matter (filterable and condensable) is the pollutant being regulated rather than "particulate matter" in order to clearly agree with the preamble.

Comment 3: Commenters 17801 and 17821 note that Footnotes 1, 2, 3, and 4 from Table 1 (p. 25125-25126) are missing so the readers cannot confirm or fully assess the intent.

Comment 4: Commenter 17909 questions whether the agency intended to insert OR vs. AND between choices for compliance based on total PM, total non-Hg metals, and individual HAP metals. The commenter recommends that the EPA clarify Table 1 and correct the text of the preamble and the rule accordingly. The commenter further states that if Table 1 is correct as written, the preamble and the rule should be updated to match and that tests that are not compared to a standard are unnecessary and should be deleted from the description of the initial and ongoing testing requirements. If Table 1 is not correct the commenter requests a detailed explanation and guidance as to how to run initial and subsequent stack tests, how to assess compliance of those results, and how to determine the "operational limit" for continuous compliance should be issued by the EPA. The commenter also requests that this portion of the proposed rule should be re-written and re-published for comment.

Response to Comments 2 - 4: Based in part on the comments received and the Agency's review of those comments, the table now identifies the type of particulate matter in the emissions limit, contains all footnotes, and has comparable rule text. The Agency sees no need for reproposal because its revisions follow from these and other comments and are a logical outgrowth of the proposal and suggested revisions.

2. Table 2:

Comment 5: Commenter17191 requests that the EPA revise Subpart UUUUUU of Part 63-Emission Limits for Existing EGUs, Table 2, Row 3 regarding IGCC units to include the SO_2 CEMs option for acid gas compliance in new and reconstructed IGCC units, adjusting the SO_2 emission limit as appropriate for existing units.

Comment 6: Commenter 17801 notes that Footnotes 5, 6, and 7 from Table 2 (p. 25126-25128) are missing so the reader cannot confirm or fully assess the intent.

Comment 7: Commenter 17909 questions whether the agency intended to insert OR vs. AND between choices for compliance based on total PM, total non-Hg metals, and individual HAP metals. The commenter states that no indication is given as to how (or even if) results of tests to determine total particulate AND total non-Hg HAP metals AND individual HAP metals, as discussed in the preamble of the rule (p.25029) and the rule itself (p. 25103),are to be compared to the standards in Table 2. If Table 2 is correct, a source could comply by running tests to determine total particulate (if results are less than 0.030 lb/MMBTU, the source passes initial certification), and no metals data would be needed at all OR a source could determine total metals and no total particulate or individual metals data would be needed, etc. Subsequently, the commenter emailed the EPA. The EPA's email stated that both particulate AND metals testing are indeed required during the initial certification testing and in subsequent tests required every 5 years. No indication was given as to how to determine compliance of the results, however the EPA did state that a relationship or correlation between filterable particulate and total particulate would be developed. The EPA also stated a relationship or correlation between total particulate and total metals emissions could be developed. The commenter requests clarification on whether this means that one would check total metals test results against the Table 2 standard (pass/fail) and check the total particulate results (pass/fail), then try to correlate those results with a Method 5 filterable test result and a PM CEMS reading. That PM CEMS reading in lb/MMBTU then would be the "operational limit" to be calculated on a 30 boiler day operating average to determine compliance. The commenter recommends that EPA clarify Table 2.

The commenter further recommends that EPA clarify Table 2 and correct the text of the preamble and the rule accordingly. The commenter states that if Table 2 is correct as written, the preamble and the rule should be updated to match and that tests that are not compared to a standard are unnecessary and should be deleted from the description of the initial and ongoing testing requirements. If Table 2 is not correct the commenter requests a detailed explanation and guidance as to how to run initial and subsequent stack tests, how to assess compliance of those results and how to determine the "operational limit" for continuous compliance should be issued by the EPA. The commenter also requests that this portion of the proposed rule should be re-written and re-published for comment.

Response to Comments 5 - 7: The agency reviewed all comments and revised the rule to allow an SO_2 alternative emissions limit for new IGCC EGUs that employ flue gas desulfurization technology, to include all footnotes, and to allow the EGU owner or operator to choose one of a number of non-mercury HAP metals alternative emissions limits and demonstrate compliance with the selected limit only. As mentioned elsewhere, the agency finds no need to repropose the rule.

3. Table 3:

Comment 8: Commenter 17881 suggests that the current reference of 63.10005, which relates to the initial compliance requirements is very broad, and a more appropriate citation would be 63.10005(f).

Comment 9: Commenters 17174 and 17691 state that the reference provided in Table 3 regarding annual performance tests for work practice standards, section 63.10005, does not contain any reference for tune-up work practice performance tests to be conducted annually. However, section 63.10006(r) contains language regarding meeting applicable tune-up work practice standards. The commenters request that the proper citation and period testing be provided in Table 3. Furthermore, Commenter 17691 adds that section 63.10006(r) states that sources required to meet an applicable tune-up work practice standard must conduct a performance tune-up according to 63.10007, but that section speaks only of performance testing, not tune-ups. The commenter requests that each section be reviewed for clarity.

Comment 10: Several commenters (17716, 18498, 17725) recommend that the phrase "performance test" in Table 3 be replaced with "boiler tune-up" to avoid confusion and be consistent with the language in 63.10005(f).

Response to Comments 8 - 10: The agency reviewed the commenters' concerns, and Table 3 in the rule has been revised to better describe the work practice standards. As the performance test for some units subject to a work practice standard is a tune-up, no change to the rule language was made.

4. Table 4:

Comment 11: Commenter 17197 provides the following recommendations for Table 4:

- If compliance with the applicable Table 1 and 2 emissions limits is being demonstrated using Hg CEMS, SO_2 CEMS, and PM CEMS, there is no need to also establish operation limits for the EGU's control equipment. Therefore, Table 4 is unnecessary, but should at least be modified to state that Hg, acid gas and total PM compliance can be demonstrated using CEMS. Section 63.9991 (a) should also be modified to read "*You must meet the requirement in paragraph (a)(1) and* ***or*** *(2) of this section.*"
- The commenter recommends that the rule should clearly state that: If continuous compliance is demonstrated with PM CEMS, a fabric filter bag leak detection system (BLDS) operating limit is not applicable. Table 4 contains both PM CEMS and Fabric Filter Control "Operating Limits" and the fabric filter operating limit requirement to install and operate a BLDS could be interpreted as additive to the PM CEMS requirement.
- The commenter suggests that operating limit for Dry Scrubber DSI and carbon injection control in Table 4 may only be intended for EGUs that demonstrate Low Emitting EGU status for Hg and qualify for alternate monitoring. The operating limit requires that the sorbent or carbon injection rate be maintained at or above the lowest 1-hour average sorbent flow rate measured during the most recent performance test demonstrating compliance with the Hg emissions limitation. However, since the Hg CEMS performance test is the initial 30-day rolling average period, the minimum 1-hour injection rate could be zero. Furthermore, the commenter states that if continuous compliance is demonstrated with Hg CEMS or sorbent trap monitoring, section 63.9991 should clearly state that establishing operating limits for dry scrubber, DSI, or carbon injection control is not required.

Comment 12: Commenter 17721 states that Table 4 should be revised as follows:

> "Dry scrubber, DSI, or DLPS injection control: Maintain the sorbent injection or addition rate at or above the lowest 1-hour average sorbent flow rate measured during the most recent performance test demonstrating compliance with the Hg emissions limitation."

Comment 13: Commenters17174and 17775 suggest that the intended reference provided in Table 4 regarding fuel analysis procedures to demonstrate compliance with the applicable limits may be 63.10011(c) and not 63.10011(d). No provisions for fuel analysis compliance are found in the reference. Similarly, Commenter 17881 states that the Fuel Analysis requirement should reference 63.10011(c)(3-6) as applicable.

Comment 14: Commenter 17675 recommends that the language in Table 4 be revised to allow flexibility when implementing the parametric monitoring requirements for EGUs. The commenter points out that parameters determined at the maximum operating rate(s) as required by the language in the proposed standard will not be attainable over all levels of operation without the flexibility to set ranges of parameters that vary with operating levels, heat input, or electrical output of the EGU historical data and multiple tests to be utilized when establishing parameter ranges for operating parameters, consistent with 63.864(j) (Part 63 subpart MM).

The commenter also indicates that paragraph 2.a (operating limits for acid gas scrubbers) contains clarity issues and a possible error. The paragraph is unclear if the requirements to "maintain the pH at or above the lowest 1-hour average pressure drop across the wet scrubber" are intended to apply to pH and liquid flow rate; pressure drop and liquid flow rate; or pH, pressure drop, and liquid flow rate. However, if the EPA intended to regulate pressure drop, regulation/monitoring should be removed from the requirements for acid gas scrubbers that utilize spray absorption because there is no way to adjust or control the pressure drop, nor does it have any relationship to the acid gas scrubbing efficiency of a spray absorber.

Comment 15: Commenter 17821 notes that in Table 4, pH is incorrectly referenced "2. Wet acid gas scrubbers... a. Maintain the pH at or above the lowest 1-hour average pressure drop." Also, pH is omitted from the description on page 25,112 of how to monitor various operating parameters.

Comment 16: Commenter 17808 notes inconsistencies between the operating limits specified in Table 4 and Table 7. Page 25030 of the preamble states that the operating limits for an ESP would be based on the "minimum hourly values" for each test run; however, Table 7 requires sources to "collect secondary voltage and current... every 15 minutes during the entire each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run."

Comment 17: Commenter 17881 states that the requirement that the injection rate shall be maintained at or above the lowest 1-hr average is in conflict with the definition of minimum sorbent injection rate provided in 63.10042, which states that the minimum rate means 90% of the test average sorbent injection rate for each sorbent measured during the most recent performance test.

Commenter 17881 also states that the Performance Testing requirement should specify that operating load must be monitored and recorded.

Response to Comments 11 - 17: The commenters' concerns are moot, for with the exception of a new option for meeting the non-Hg HAP metals emissions requirements through the use of a PM CPMS, the rule no longer requires operating parameters for pollutants.

5. Table 5:

Comment 18: Commenter 17886 states that Table 5 specifies a Method 5 front half temperature of 320 degrees F and should instead reference Method 5B to be consistent with any standard.

Commenter 17886 also states that Table 5 specifies quantification of HF, but should not since there are no limits given for HF.

Response to Comment 18: As explained elsewhere, the agency disagrees with the commenter, and the rule continues to require the use of Method 5, not 5B. The rule continues to contain an HF emissions limit for liquid oil-fired units, so the comment is moot.

Comment 19: Commenter 18498 states that Table 5 should be revised to include the following reference methods as an option for compliance demonstration:

- EPA Method 2H and Conditional Test Method 41 (wall effects adjustment for flow)
- EPA Method 26A (HCl- option for dry stacks)
- EPA Method 320 (HCl- FTIR option)
- EPA Method 5B, 17 (total, filterable PM)

Commenter states that the table should indicate that Method 2 (or equivalent) need only be used if necessary to calculate output-based emissions.

Response to Comment 19: The agency reviewed the commenter's concerns, and the rule is revised to include Method 2H, 26A, and 320; other Methods did not meet this rule's criteria and remain excluded.

Comment 20: Several commenters (17716, 17725, 18498) point out that the reference provided for Table 5 (Appendix A) does not address monitoring certification and ongoing monitoring requirements for PM and HCl CEMS.

Response to Comment 20: The agency reviewed the commenter's concern, and the table now has appropriate monitoring certification and monitoring requirements.

Comment 21: Commenter 18034 states that the reference footnote 9 in Table 5 (section 63.10005(l)) does not address calculating emissions during startup and shutdown operations.

Response to Comment 21: The comment is moot because rule now requires work practice standards, not adherence to emissions limits, during periods of startup or shutdown.

Comment 22: Several commenters (17716, 17725, 18498) note that for the SO_2 CEMS (Item 5) in the "using" column for Item a, the table should include the alternative to use Part 75 requirements for "installation," "operate," and "maintain CEMS." See Section 63.10010(e). Also, the table refers to Sections 4.1.3 and 5.3 of Appendix A to the subpart, but SO_2 is never mentioned in Appendix A.

Response to Comment 22: The agency has reviewed the comments, and the table now references Part 75 requirements and contains correct references.

Comment 23: Several commenters (17675, 17718, 17881) state that section 63.10010(h) discusses installing CPMS as specified in Table 5 of this subpart. This section should instead refer to Table 4 which contains operational parameters rather than Table 5 which contains performance testing requirements. If the section is correctly referencing Table 5, then it is unclear what CPMS are required.

Response to Comment 23: The comment is moot, as table 6 now contains operational parameter instructions for those EGU owners or operators who choose to use PM CPMS.

Comment 24: Commenters 18498 and 17725 recommend that the EPA add the text below to Table 5, as applicable:

> "Alternatively, for an affected source that is also subject to the O_2or CO_2 monitoring requirements of Part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality assure the data from an O_2or CO_2CEMS according to Part 75 of this chapter in lieu of the procedures in paragraphs b(1) through b(3) of this section."

Commenter 18498 also recommends Section 60.10010(b) should reference Part 75 in lieu of the alternate requirements specified in Appendix A to Subpart UUUUU with regard the $O_2$and CO_2 CEMS requirements.

Response to Comment 24: The agency reviewed the commenters' concerns, and the rule now references Part 75 requirements in both table 5 and in rule text.

Comment 25: Commenter 17881 states that exhaust flow and moisture should only need to be determined if you are complying with the lb/MWh limit. The O_2/CO_2 levels should only need to be determined if you are complying with the lb/MMBtu standard. The commenter recommends that the EPA clarify the language in Table 5 in order to prevent the collection of data which is not needed to assess compliance with the chosen emission limit form (i.e., heat input or electrical output basis).

Response to Comment 25: The agency has reviewed the commenter's concern, but disagrees with the concern. The table is not changed, for an owner or operator need not provide the exhaust flow or moisture levels if his or her EGU complies with an electrical output based standard.

Comment 26: Commenters 18498 and 17725 request clarity regarding performance specification for HCI. Table 5 lists Performance Specification 6 but it does not apply since it is for systems that measure pollutant emissions in units of mass per unit of time. The EPA has developed no performance specification for non-FTIR based HCI CEMS. The commenters state that the lack of a performance specification for HCI (coupled with limited utility HCI operating experience, particularly for compliance near the detection limits of the systems) makes it difficult to provide meaningful comments.

Response to Comment 26: The agency disagrees with the commenter, for an FTIR CEMS, subject to PS 15, could be used for HCl CEMS. Should an owner or operator of an EGU not choose to use an FTIR CEMS to demonstrate compliance with HCl emissions, he or she could use quarterly emissions testing or wait and use non-FTIR HCl CEMS using the separate HCl CEMS performance specifications under development but expected to be promulgated before the rule's compliance date.

Comment 27: Commenter 17881 states that bullet c. should read: "Determine oxygen OR carbon dioxide concentrations of the stack."

Response to Comment 27: This change to the rule has been made.

Comment 28: Commenter 17881 states that the reference to a 30-day rolling average is not appropriate. Per 63.10005(k)(2), a 28-30 day integrated average value is being established, not a 30-day rolling average.

Response to Comment 28: The comment is moot because rule now requires a 30-day integrated average value.

6. Table 6:

Comment 29: Commenter 17881 states that Table 6, which provides the fuel analysis requirements, does not address gaseous fuels at all even though gaseous fuel may be co-fired (for purposes other than startup and flame stabilization) with one or more fossil fuels which are regulated in the proposed EGU MACT, particularly liquid oils.

Commenter 17881 states that in the requirements for HF, there is a typo in bullet f.; it should read "measure fluorine concentration in fuel sample" instead of chlorine.

Response to Comment 29: The comment is moot, for the rule no longer requires fuel analysis for pollutants.

7. Table 7:

Comment 30: Several commenters (17174, 17808, 17881) state that the reference provided in the table regarding emission operating limits through fuel analysis should be 63.10011(b) as opposed to 63.10011(c).

Comment 31: Commenters 17775 and 17808 state that the table only lists the operating limits for ESPs for units that operate wet scrubbers, therefore conflicting with other provisions, including proposed section 63.10011(b)(6)(iii). The table does not include the operating parameters for a unit with an ESP, but no wet scrubber.

Comment 32: Commenter 17721 states that Table 7 should be revised to add operating limits for sources using dry scrubbers, DSI, or DLPS to comply with PM, Hg, or non-Hg HAP metals emission limits as follows:

1 Particulate matter (PM), mercury (Hg), or other non-Hg HAP metals:

d. Dry scrubber, DSI, or DLPS operating parameters

i. Establish a site specific minimum sorbent injection or addition rate operating limit according to §63.10011(c). If different Hg sorbents are used during the Hg performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.

(1) Data from the sorbent injection or addition rate monitors and Hg performance test.

(a) You must collect sorbent injection or addition rate data every 15 minutes during the entire period of the performance tests;

(b) Determine the average hourly sorbent injection or addition rates of the three test run averages measured during the performance test.

Comment 33: Commenter 17721 states that Table 7 should be revised to add operating limits for sources using dry scrubbers, DSI, or DLPS to comply with HCl or HF emission limits as follows:

2. “Hydrogen Chloride (HCL) or hydrogen fluoride (HF)

(b) Dry scrubber, DSI, or DLPS operating parameters

(1) Establish a site specific minimum sorbent injection or addition rate operating limit according to §63.10011

(c) If different Hg sorbents are used during the Hg performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.

(1) Data from the sorbent injection or addition rate monitors and Hg performance test.

(a) You must collect sorbent injection or addition rate data every 15 minutes during the entire period of the performance tests;

(b) Determine the average hourly sorbent injection or addition rates of the three test run averages measured during the performance test.”

Response to Comments 30 - 33: The comments are moot, for the rule no longer requires establishment of operating parameters for pollutant control devices.

8. Table 8:

Comment 34: Several commenters (17716, 17725, 17775, 18498) point out that Table 8 erroneously refers to “QA Procedure 5” for the PM CEMS QA/QC requirements and should refer to “Procedure 2” instead.

Comment 35: Commenter 17881 states that the references in the “you must” column should be re-checked, as there are several that are incorrect. For example, 7.a. should be QA Procedure 2, not 5, and 7.b. should be “30 boiler operating day average mg/dscm values” rather than the current “30 boiler operating mg/dscm values.”

Comment 36: Commenters 17775 and 17808 state that references to section 63.1011(c) in Table 8 may be intended to reference section 63.1011(b) instead.

Comment 37: Several commenters (17800, 17725, 18498) state that the method for calculating 30 rolling averages in Table 8 is not consistent with the method in section §63.10010(g). Table 8 states that the source should convert “hourly emissions concentrations to 30 boiler operating mg/dscm values,” which suggests that compliance is assess based on the average of 30 individual daily values. However, section 63.10010(g)(5) states that 30-day rolling average is calculated as “the average of all of the hourly particulate emissions data for the preceding 30 boiler operating days.” Commenter 17800 recommends that the EPA consider changing this averaging time to a 12-month rolling average consistent with the Illinois MPS rule to help capture the variability associated with the operation of an EGU. If the 30-day average is not updated to be consistent with the Illinois MPS rule, the commenter suggests that the methodology in Table 8 be updated to be consistent with the other sections.

Comment 38: Commenters 18498 and 17725 note that Table 8 requires CPMS data to be reduced to 12-hour block averages; however, this requirement is not specified in section 63.10010(h).

Comment 39: Commenter 18539 states that Table 8 refers to opacity operating limits however it appears that no other references to opacity operating limits exist. The commenter requests that the EPA clarify whether the intent is to allow for opacity operating limits exist in the proposed rule.

Comment 40: Commenter 17721 states that Table 8 should be revised as follows:

"4. Dry scrubber, DSI sorbent, DLPS sorbent, or carbon injection rate

a. Collecting the sorbent or carbon injection rate monitoring system data from the dry scrubber, DSI, or DLPS according to §63.10010 and §63.10020; and

b. Reducing the data to 12-hour block averages; and

c. Maintaining the 12-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to §63.10011(c)."

Response to Comments 34 - 40: The agency finds the comments are moot, as table 8 has been revised to remove all requirements associated with developing and maintaining operating limits for pollution control devices.

9. Table 9:

Comment 41: Several commenters (17913, 17915, 17174) request that the reference to startup, shutdown, and malfunction (SSM) plans in Table 9 should be removed because it conflicts with the text in Table 10 and the preamble that states SSM plans are not required.

Comment 42: Commenter 17775 indicates that the Table 9 should be evaluated for the following inconsistencies:

- The error, "information required in §63.10031(c)(1) through (11) through (11)," should be addressed. In addition, the EPA should review the text and consider referencing §63.10031(c) subsection (12) as well. Commenter 17881 notes this inconsistency as well.
- The table specifically requires submission of a startup, shutdown, and malfunction report containing the information in §63.10(d)(5)(i) at 1.d and 2, however, Table 10 states that §63.10(d)(5) does not apply. The EPA should address the inconsistency and correctly identify applicable reporting requirements.

Response to Comments 41 - 42: The Agency has reviewed the commenters' concerns and revised the table by removing requirements to develop and submit a startup, shutdown, or malfunction plan and corrected the text cite language, as suggested by the commenter.

10. Table10:

Comment 43: Commenter 17775 states that section 63.1(a)(4)(i) requires each standard to "identify explicitly whether each provision in this subpart A is or is not included" and that the EPA proposes to address applicability in Table 10. The commenter provides the following instances of inconsistencies in Table 10 with respect to applicability:

- EPA identifies §63.6(h)(2)-(9), and §63.9(f), and (g)(2) as applicable. Proposed §63.10030(a) also requires compliance with §63.9(f). These provisions pertain solely to compliance with opacity and visible emission standards. Since the proposed rule does not include any applicable opacity or visible emission standards, these portions of the general provision do not apply and Table 10 should be revised accordingly.

- EPA fails to identify whether §63.6(e)(1)(iii) applies.
- EPA fails to identify whether §63.8(a)(1), (2), and (4), (b), (c)(2), (4)(i), (5), (6), (8), (d)(1), (d)(2), (f), or (g) apply. Sections (c)(1)(ii), (3), (4)(ii), (7)(i), (8), and (d) are referenced in proposed §63.10000(d)(4) and §63.8(e) is referenced in proposed §63.10030(a), but not in Table 10. Some of these provisions apply solely to opacity monitoring, and should not apply, but the EPA must state whether or not they are included. The EPA should provide that CEMS meeting the requirements of Part 75 are exempt from the "performance evaluation" test plan and notices in §63.8(e). The EPA also should make clear that those requirements do not apply to "calibration error testing," since "performance evaluation" is defined in §63.2 to include both relative accuracy testing and calibration error testing.
- EPA fails to identify whether §63.10(b)(2)(x)-(xiii) apply.
- EPA identifies §63.10(c) as applicable in its entirely, but later in the table separates out §63.10(c)(7) and (8) as applicable and §63.10(c)(10), (11), and (15) as not applicable. The EPA also cites §63.10(c) in its entirety as requirements of the site-specific monitoring plan in proposed §63.10000(d)(7). Note also that §63.10(c)(7) and (8), which specify recordkeeping for sources with continuous monitoring requirements, require reporting of "excess emissions" "as defined in the relevant standard(s), that occur during startups, shutdowns, and malfunctions of the affected source" and those that occur "during periods other than startups, shutdowns, and malfunctions." Proposed subpart UUUUU does not define "excess emissions" for any standard and does not exempt periods of startup, shutdown, or malfunction.
- In determining whether the recordkeeping requirements in §63.10(b) and (c) apply, the EPA must ensure its compliance with the PRA. Under 5 C.F.R. §1320.5(d)(2), the EPA cannot require retention of such records for more than 3 years, unless the agency demonstrates in its OMB submission that that a longer retention period is necessary to "satisfy statutory requirements or other substantial need."
- EPA fails to identify whether § 63.10(d)(3)-(4) are applicable.

Response to Comment 43: The agency reviewed the commenter's concerns, and the rule and table have been revised, where appropriate, to remove inconsistencies.

Appendix A:

Comment 44: Commenter 17775 points out the following inconsistencies in Appendix A:

- Appendix A §4.1.1.3 incorrectly refers to Table A-2 instead of Table A-1.
- The conversion factors used in Appendix A §6.2.1.2, Equation A-2 and Equation A-3 should be the consistent. Appendix A §6.2.1.2 includes a factor of 6.24x10-11 to convert Hg concentration from µg/scm to lb/scf whereas Equations A-2 and A-3 use a constant of 6.236x10-11.
- Appendix A says that quarterly reports must include the information in §§7.1.2-7.1.19, however §§7.1.11-7.1.19 do not exist.

Comment 45: Commenter 17881 suggests that the following changes be made regarding Hg Monitoring Provisions in order to harmonize Appendix A of the EGU MACT with the requirements of 40 CFR Part 75, as most (if not all) units subject to the EGU MACT will also be subject to 40 CFR Part 75 emissions monitoring:

- Table A-2, Flow Rate RATA Specifications: "40 CFR Part 75, App. A, Section 3.3.4 also provides an alternate performance specification of not > 2.0 feet per second (FPS) when the average RM value is ≤ 10.0 FPS."
- Table A-3, Daily Calibration Error Test: The first bullet should read "use zero gas and either a mid- or high- level gas," as daily calibration error tests are generally conducted using a zero and upscale calibration gas.
- Table A-4, Daily Calibration Error Test for O2 or CO2: The first bullet should read "use zero gas and either a mid- or high- level gas," as daily calibration error tests are generally conducted using a zero and upscale calibration gas.
- Table A-4, Daily Interference Check for Flow Rate: "40 CFR Part 75, App. B, Section 2.1.4(a) allows ≤ 6.0% of the calibration span."
- Table A-4, Flow Rate RATA: "The 40 CFR Part 75 App. B, Section 2.3.1.2(d) alternate specification for flow monitors of ± 1.5 FPS when the average RM value is ≤ 10 FPS should also be allowed."

Commenter 17881 also asks if the EPA intends moisture monitoring systems consisting of wet and dry O_2 monitoring systems to be exempt from any sort of daily calibration error test requirement. For such moisture monitoring systems, the commenter states that 40 CFR Part 75 generally requires those same on-going quality assurance tests as are required for O_2 diluent monitors however Appendix A of the proposed EGU MACT only appears to require a RATA test.

Response to Comments 44 and 45: The reference to Table A-2 in section 4.1.1.3 of Appendix A was a typographical error and has been corrected. The conversion factors in Equations A-2 and A-3 have been made consistent; both factors are now 6.24 x 10E-11. The reference in the quarterly reporting section of Appendix A to section 7.1.19 was a typographical error and has been corrected.

The EPA has not incorporated the commenter's suggestion to harmonize the information in Tables A-2 and A-4 with Part 75, because Tables 2 and 4 have been deleted from Appendix A. The agency has decided against reproducing part 75 certification and QA specifications in Appendix A for the flow rate, diluent gas, and moisture monitoring systems that are used to convert Hg concentrations to units of the standard. Instead, section 3.2.3 of Appendix A simply states that these monitoring systems must be certified, operated, maintained, and quality-assured according to 40 CFR part 75. The EPA has incorporated the edit to Table A-3 (which has been renumbered as Table A-2) suggested by the commenter, i.e., that the daily calibration error tests of the Hg CEMS must be done with a zero gas and either a mid-level or high-level calibration gas. Finally, moisture monitoring systems consisting of wet and dry O_2 analyzers are not exempted from daily calibration error tests. The O_2 monitors in these systems must meet the daily calibration requirements of part 75.

8D - Rule: Language

Commenters: 16513, 17174, 17191, 17254, 17386, 17622, 17623, 17655, 17656, 17675, 17677, 17681, 17689, 17691, 17696, 17705, 17711, 17714, 17716, 17718, 17721, 17725, 17730, 17731, 17752, 17756, 17758, 17775, 17781, 17795, 17796, 17800, 17801, 17808, 17821, 17843, 17848, 17870, 17881, 17909, 17912, 18014, 18027, 18034, 18037, 18498, 19120, 19536/19537/19538, 18023

1. Clarifications.

Comment 1: Several commenters request that the language of the rule be updated to clearly state the requirements for each category, subcategory, pollutant and compliance option used at facilities. Commenter 18034 requests that the EPA clarify how to determine emission rates during a startup, shutdown, or malfunction situation.

Response to Comment 1: We believe that the final rule language is clear.

Comment 2: Multiple commenters (17677, 17730, 17758, 17909, 17912) request that the preamble should be updated and clarified to be consistent with the rule language. For example, Commenter 17912 notes that the preamble to the proposed rule states the EPA's intent to exclude stationary combustion turbines from this rule. However, the proposed rule text excludes only those stationary combustion turbines located at major sources. The commenter requests that the EPA revise the rule text to confirm its intent to exclude all stationary combustion turbines, including those located at minor source facilities.

Response to Comment 2: We do not believe that the regulatory language distinguishes between major and area source facilities as the term "major source" is not used.

Comment 3: Commenter 17656 urges the EPA to make clear precisely what requirements apply to each category/subcategories and the different options for compliance that are available. Commenters 17677 and 17730 both oppose leaving such clarification for follow-on guidance.

Response to Comment 3: We believe that the final rule clearly presents the compliance options as requested by commenters.

Comment 4: Commenter 17730 appreciates the variety of options that the EPA has provided for sources to demonstrate ongoing compliance, but states that several of the options will require clarification in order for facilities to understand the options, applicability, and to demonstrate compliance. The commenter recommends that the EPA revise the proposal to make clear exactly what requirements and rationale apply to each compliance option. The commenter points out that the EPA has the opportunity to electronically publish each of the different subcategories and the different options in a clear, direct, and plain language fashion with a limited amount of references to other subsections, or mentions of "as applicable. The EPA has substantively failed to provide a clear and readily understandable set of requirements for sources in this proposed rulemaking.

Response to Comment 4: The agency believes that the final rule provides a clear and readily understandable set of requirements, and the rule contains clarifications where appropriate.

2. CEMS comments.

Comment 5: Multiple commenters (17623, 17655, 17716, 17681, 17800, 17821 and several others) request that the EPA review and update the language regarding CEMS, performance testing and operating limits.

Response to Comment 5: As mentioned earlier, the agency has reviewed the commenters' concerns and revised the rule where appropriate.

Comment 6: Commenter 17716 states that the proposed rule should be clarified to explicitly exempt sources using a CEMS for compliance for a particular pollutant from all fuel sampling requirements for that pollutant. The commenter states that the fuel sampling requirements apply only to those units that demonstrate compliance through performance (i.e., stack) testing for a particular pollutant, but §63.10005(a) states that "performance testing" may also consist of CEMS operating data, thereby creating ambiguity about whether units using a CEMS for compliance must also meet the fuel sampling requirements.

Comment 7: Commenters 18498 and 17725 recommend that the EPA revise §63.10007 to indicate that the fuel sampling and operating parameter limits are not required when the applicable HAP (or surrogates) are monitored using a CEMS.

Response to Comments 6 - 7: The agency agrees with the commenters, and the rule has been revised to not require fuel sampling of pollutants where CEMS are used for compliance purposes.

Comment 8: Commenter 17718 states that it is not clear that installing and operating CEMS for the regulated HAP and surrogates will relieve a source of the burden of also monitoring compliance with operating limits on control equipment based on a performance stack test. The commenter recommends that the EPA require no proof of compliance beyond a properly calibrated and installed CEMS, and that the EPA revise both the language and tables in the rule to clarify its intent as it relates to CEMS used for demonstrating compliance.

Comment 9: Several commenters (17655, 17696, 17716) state that the language regarding performance testing and compliance is unclear and should be revised so that facilities can clearly understand and follow regulations. Commenter 17655 specifically notes that Sections §63.10005(a), §63.10011(a), and §63.10011(b) are difficult to interpret. For example, it is unclear whether facilities using CEMS are also required to track performance parameters to show compliance. The commenter requests that the EPA use consistent and clear language to enumerate the requirements for facilities with and without CEMS.

Response to Comments 8 - 9: The comments are moot because rule no longer requires emissions control device operating parameters or limits when CEMS are used for compliance purposes.

Comment 10: Commenter 17821 states that the best method of determining initial compliance is with the applicable reference method. Reference methods are used to certify the CEMS on a source. The commenter recommends that the EPA specifically state in the rule that the use of Reference Methods are required to demonstrate initial compliance with the emission limitations in this rule.

Response to Comment 10: The methods suitable for conducting performance tests for this rule, or any rule, are defined in large part by specified averaging time. In many cases, this final rule clarifies that the averaging time for initial and periodic compliance testing is the result of three relatively short term performance test runs and through the use of manually operated test methods found in Appendix A of 40 CFR part 60 or 63. This approach to conducting initial and periodic performance tests applies to metal HAPs, PM, and HF and HCl, and is consistent with the commenter's suggestion. On the other hand, for sources who opt to use Hg or SO_2 CEMS in lieu of manual performance testing, the averaging time of the rule is 30 unit operating days. This long averaging time precludes the use of manual performance test methods on a practical basis. The final rule specifies that CEMS or sorbent trap monitoring be the performance test method for determining initial and continuous compliance with limits expressed as a 30-day average value.

Comment 11: Commenter 17623 requests that the language in both the preamble and the rule be updated to clarify that testing is not mandated for pollutants being controlled through a surrogate and performance standards are not required when a CEMS is employed. In the preamble, the commenter requests that the clause that states "and an operating limit would be established" should be removed because it is duplicative of the CEMS requirement.

Response to Comment 11: The agency has reviewed the commenter's concern, and while the rule has been revised so that neither emissions testing other than RATAs (or initial calibration for PM CEMS) nor operating limits are required for EGUs that use CEMS for compliance purposes, the rule has not been revised to exclude the requirements of performance specifications when CEMS are used for compliance purposes.

Comment 12: Commenter 17696 states that sections 63.10000(c),(d), 63.10005, 63.10006, 63.10008, 63.10011, and 63.10021 are complex and confusing and in some cases inconsistent with the preamble and examples in the rule. The commenter cites language on whether a coal-fired EGU without an HCl CEMS is required to conduct monthly fuel analysis for chlorine from sections 63.10005(a), 63.10006(s), and 76 FR 25,051 to illustrate the difficulty and contradictions contained in the rule.

Response to Comment 12: The agency has reviewed this concern, and the rule has been revised for consistency and clarity.

Comment 13: Commenter 17796 suggests that the Hg compliance metric be succinctly stated in section 63.10010(1). The commenter states that although section 63.10010(g)(5) for PM CEMs discusses that compliance is based upon a 30 boiler operating day rolling average emissions rate on a daily basis, the commenter was unable to find this language for the Hg compliance limit. Section 63.10010(1) refers the reader to Appendix A but Appendix A does not state the compliance average.

Response to Comment 13: The agency disagrees with the commenter's concern, for the rule states the initial Hg CEMS compliance requirement at §63.10005(a)(2) and the ongoing Hg CEMS compliance requirement at §63.10021(a).

Comment 14: Commenter 17718 notes that sections 63.10005(d)(3)-(6) state if CEMS are going to be used for initial compliance determinations then the average hourly concentrations obtained during the first 30-day operating period will be used "after the monitoring system is certified." The commenter requests that the EPA clarify when the 30-day operating period begins if the systems are already certified (e.g., current SO_2 or PM CEMS being used for 40 CFR Part 75 and/or 40 CFR Part 60 monitoring programs).

Response to Comment 14: The EPA disagrees that any additional clarification is needed in the rule. Owners or operators of new EGUs have up until 60 days after the rule appears in the Federal Register or upon startup, whichever is later; or, for existing units, at least 3 years and 60 days after promulgation to be in compliance with the emissions limits and standards.

Comment 15: Commenter 17796 requests that the rule clearly state what the acceptable data capture percentage is for Hg, HCl and PM CEMs. The method of counting hours when a monitor is out of service, as hours of monitor down time and using this value to determine the % of monitor availability is consistent with NSPS requirement. For Hg, section 60.490a paragraph (p)(4) discusses the need for 75 % data capture on a monthly basis for a monitor to achieve an acceptable % monitor availability and to be able to demonstrate consistent compliance. However, the commenter states that this whole section will become obsolete and removed from the NSPS if the proposed changes to the NSPS and NESHAP rules go into effect.

Response to Comment 15: The agency considered the commenter's suggestion but made no change to the rule. The rule contains no minimum acceptable data capture percentage, for the rule at §63.10010(j) requires data to be collected at all times an EGU is combusting fuel except for periods of monitoring system malfunction, out-of-control operation, or quality assurance or control activities.

Comment 16: Commenter 17622 requests that the EPA clarify the statement "continuous compliance would be determined using a PM CEMS with an operating limit established based on the filterable PM values measured using Method 5." (76 FR 25029/2). The commenter recommends that the EPA explicitly state if the PM CEMS would be correlated against the filterable PM fraction of total PM to avoid confusion.

Response to Comment 16: The agency considered this and other comments, and the rule has been revised to include a filterable PM, but not total PM, alternative emissions standard. The rule also allows use of PM CPMS, which would have an operating limit, as well as PM CEMS, which would allow direct measure of compliance, as compliance options.

Comment 17: Commenter 17675 further recommends that the wording in section 63.10010(a) should be updated to clearly state that Hg CEMS and/or sorbent traps can be used for Hg monitoring, rather than implying that both CEMS and sorbent traps are required. Similarly, Commenter 17821 recommends that the EPA clarify the term "demonstrate initial and continuous compliance through the use on a continuous…HCl…[and]…Hg CEMS or a sorbent trap…system" to indicate that a "certified CEMS" must be used. The term "certified CEMS" means that all of the required testing outlined in this rule, or in applicable portions of 40 CFR parts 60 or 75, have been completed, and that the results of the testing met the requirements of the applicable rules. Without clarification, this section could be interpreted to mean that certification of the CEMS is not required before using it for purposes of demonstrating compliance.

Response to Comment 17: Although the agency appreciates the commenter's concern, no change was made to the rule, for §63.10010(g) requires Hg CEMS or sorbent trap monitoring systems to be certified.

Comment 18: Commenter 17716 requests the following corrections and clarifications regarding CEMS:

- EPA should evaluate and revise the data reduction citations to be consistent throughout the rule. The commenter specifically provides the following example: sections 63.10010(b)(4); 63.10010(c)(4); 63.10010(d)(4); 63.10010(e)(4); and 63.10010(g)(4) all state: "Reduce the CEMS data as specified in section 63.8(g)(2) and (4)." However, section 6.1.1 of appendix A relates data reduction from "Hg CEMS and (as applicable) flow rate, diluent gas, and moisture monitoring systems to hourly averages in accordance with section 60.13(h)(2) of this chapter." The commenter suggests that requirements in section 60.13(h)(2) are more complete since it addresses "partial operating hours" and other data needs. Commenters 18014-A2, 17725 and

18498 also make the same recommendation.

- For SO_2 CEMS, section 63.10021(a)(13) does not include the option to use the Part 75 certification and ongoing QA/QC requirements as allowed in section 63.10010(e). Commenter 17725 also notes this issue.
- For Hg CEMS, section 63.10021(h)(ii) states the "Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 5 in Appendix F of 40 CFR Part 60." This contradicts section 63.10010(f) which references appendix A of this subpart and should be revised to reference section 5 to appendix A. Commenter 17725 also notes this contradiction.

Comment 19: Commenter 17881 requests the following corrections and clarifications regarding CEMS:

- Section 63.10011(b)(6) should clarify how these requirements apply in cases where CEMs are used for compliance.
- The reference in section 63.10021(a)(10)(i) is inconsistent because section 63.10010(a) does not require the installation of O_2 CEMS while section 63.10010(b) allows installation of CO_2 or O_2 CEMS.
- In sections 7.1.3.5 and 7.1.4.8, the EPA requires that hourly records of % monitor availability (PMA) be maintained for Hg CEMS and sorbent trap monitoring systems. The PMA concept is employed in 40 CFR Part 75 in the context of determining appropriate missing data substitution procedures. As missing data substitution will not be allowed in the context of Hg monitoring, the commenter requests that these requirements should be deleted from proposed appendix A.

Response to Comments 18 - 19: The agency has reviewed and considered each of the commenters' suggestions. The rule now uses Part 75 data reduction and quality assurance procedures for those CEMS also used in Part 75; Hg CEMS and sorbent traps are subject to the requirements of appendix A; HCl or HF CEMS are subject to the requirements of appendix B. The commenter's concern over simultaneous control device operational parameter monitoring and CEMS is moot, for the rule no longer requires control device operational parameter monitoring. The inconsistency between the use of CO_2 or O_2 CEMS has been clarified; the rule now allows either type of CEMS. The rule retains the requirement to report Hg CEMS or sorbent trap monitoring data availability; although the Agency agrees that there is no minimum data availability requirement for these types of monitors, the Agency sees no inconsistency between the monitoring operational and data availability reporting requirements.

Comment 20: Commenter 18498 states that as proposed, the EGU MACT Rule does not include provisions to use the Part 75 "conditionally valid data procedures." For example, if a CEMS fails a linearity check the CEMS remains out-of control until the successful completion of a subsequent linearity check (reference section 60. 13(h)(2); section 63.8(g)(2) and (4)). This would require the operator to invalidate the Part 75 conditionally valid data (for SO_2, CO_2, O_2 or flow monitors) for the EGU MACT recordkeeping and reporting purposes. The commenter recommends that the EPA allow quality assured data from a CEMS certified and operated in accordance to Part 75 to be used for EGU MACT compliance (with the exception of bias adjusted data and values derived from missing data substitution procedures).

Response to Comment 20: As mentioned elsewhere, the rule now allows use of Part 75 procedures for quality assurance and control activities for those monitors also used in Part 75.

Comment 21: Commenters18498 and 17725 note that section 63.10021(a)(10)(i) requires sources to "continuously monitor oxygen according to §§63.10010(a) and 63.10020" if you are required to install a

CEMS according to section 63.10010(a), however this contradicts the requirements in section 63.10010(b) which allow the use of O_2 or CO_2. Also, the commenters note that the majority of Part 75 affected coal-fired units utilize dilution extractive CEMS which are equipped with CO_2 analyzers and CEMS cannot measure O_2 as a diluent.

Comment 22: Commenter 17718 states that section 63.10021(a)(10)(i)and(ii)) references continuously monitoring O_2, but should also reference CO_2 monitoring as a diluent as an alternative. The following specific language changes are suggested:

- Section 63.10021(a)(10)(i): "You must continuously monitor O_2 or CO_2 according to sections 63.10010(a) and 63.10020."
- Section 62.10021(a)(10)(ii): "Keep records of O_2 or CO_2 according to section 63.10032(b)."

Response to Comments 21 - 22: As mentioned elsewhere, the rule now allows O_2 or CO_2 CEMS to be used.

Comment 23: Commenter 17718 states that section 63.10021(a)(11)(v) requires all CEMS relative accuracy test audits (RATA) to be submitted electronically using the Electronic Reporting Tool. The commenter requests that the EPA clarify whether this requirement is only applicable to CEMS RATAs performed under the requirements of the rule. The commenter also requests that the EPA clarify whether only SO_2 RATAs performed for the combined purposes of 40 CFR Part 75 and this regulation would be reported in ERT. Any annual NO_X or flow monitor RATA performed for 40 CFR Part 75 requirements would not to be reported in the ERT even though it may have been performed concurrently.

Response to Comment 23: The agency reviewed the commenter's concern and disagrees with the commenter's assertion. The rule has not been changed, for the rule covers only those EGUs subject to the rule's applicability. In the commenter's example, no NO_X CEMS RATA data would ever need to be reported electronically under this rule, but, as the commenter suggests, SO_2 CEMS RATA data from those EGUs whose owners or operators choose to use SO_2 CEMS as an alternative means of demonstrating compliance with acid gas emissions limits would need to submit those data electronically.

3. IGCC comments.

Comment 24: Commenter 17801 recommends that the EPA provide further definition and clarification regarding air pollution control devices (APCD) to account for upstream fuel cleanup (e.g., removal of particulate, Hg, non-Hg metal HAPS, sulfur and/or chloride directly from the fuel stream of IGCC units). For example, for coal-fired units with add-on APCDs, it is unclear in section 63.10006 and/or Table 7 as to the testing program or operating limits to which IGCC would be subject. There is not an applicable combination of CEMS/APCD described that pertains to IGCC which could allow for emissions testing every five years for some coal-fired EGU sources instead of every other month for those sources without add-on controls. The EPA should consider any upstream gasification/fuel clean-up (e.g., AGR, SRU, PM scrubber) in the same way that coal-fired EGUs are credited for post-combustion or other APCD. IGCC should not be burdened with additional testing requirements if reduced testing programs are allowed for coal-fired units with add-on APCDs.

Response to Comment 24: The agency considered the commenter's concerns, but the rule has not been changed. An IGCC unit can qualify for reduced frequency emissions testing under the existing rule's LEE provisions, should an IGCC EGU owner or operator choose to use emissions testing as the means for demonstrating compliance with the emissions limits.

Comment 25: Commenter 17191 notes that footnote number 206 appears to preclude the use of the SO_2 monitoring option for IGCC units. The commenter suggests that this may be an unintentional consequence from carrying over language of other EGU category requirements for consistency and requests that either the footnote be removed or modified to state, "The alternate SO_2 limit may not be used if your EGU does not have some form of pre- or post-combustion desulfurization system." The commenter suggests that the modification is necessary because IGCC units do not require "flue gas desulfurization systems" as the sulfur is removed in the gasification phase (i.e., no post-combustion "flue gas" desulfurization is necessary). Instead, removing the reference to "flue gas" and replacing it with "pre- or post-combustion" accomplishes the objective of requiring desulfurization controls as a prerequisite for SO_2 monitoring option without inadvertently preventing new and reconstructed IGCC units from pursuing the SO_2 alternative.

Response to Comment 25: We believe that IGCC EGUs qualify for the use of SO_2 monitoring as a surrogate for HCl. We have also clarified the definitions.

Comment 26: Commenter 17821 states that the EPA needs to revise the description and definitions of the IGCC APCD to account for upstream fuel cleanup and/or pollution prevention measures. For example, the technology used in IGCC units directly removes contaminants (such as particulate, Hg, non-Hg metal HAP, sulfur, chloride) directly from the fuel stream of IGCC units. In this respect, IGCC is more akin to a natural gas-fired combined cycle unit, since it burns a syngas, which is cleaner than the coal combusted in a pulverized coal unit. The EPA should reflect that IGCCs use upstream gasification/fuel clean-up (for example, AGR, SRU, PM scrubber) in the same way that coal-fired EGUs are credited for post-combustion or other air pollution control equipment such as SCR, ESP, and FGD. It makes no sense for IGCC to have additional testing burdens if reduced testing programs are allowed for coal-fired units with APCD. The EPA recognizes that an IGCC unit is a distinct type of electric generating unit by proposing a separate subcategory for IGCC units. The EPA needs to further acknowledge the process differences between IGCC units and PC units by providing clarification that for purposes of this MACT the affected facility is the combustion turbines and any emission limitations apply to the heat recovery steam generator HRSG stack. Commenter recommends that the EPA needs to provide further clarification that all upstream fuel clean-up in the IGCC process qualifies as control equipment, thereby not putting any additional testing burdens on IGCC units when reduced testing is allowed for coal-fired units with add-on pollution control equipment.

Response to Comment 26: As mentioned elsewhere, the agency considered the commenters' concerns, but the rule has not been changed. An IGCC unit can qualify for reduced frequency emissions testing under the existing rule's LEE provisions, should an IGCC EGU owner or operator choose to use emissions testing as the means for demonstrating compliance with the emissions limits.

Comment 27: Commenter 19114 states that for IGCC units, the EPA should clarify the use of heat input and generation output terminology to account for (1) differences between coal-based (gasifier feedstock -based) and syngas-based heat input; and (2) differences between syngas-based and natural gas-based output during co-firing operations.

Response to Comment 27: The EPA is regulating IGCC units that burn synthetic gas derived from coal and/or solid oil-derived fuel. Natural gas-fired EGUs are not subject to this final rule.

4. Fuel sampling and analysis.

Comment 28: Commenters 17716 and 17725 request that the EPA clarify whether units that fire a single type of fuel (e.g., diesel oil) are exempt from all fuel sampling and analysis requirements. Although section 63.10005(c)(4) exempts units that fire a single fuel type from conducting fuel analysis as part of the initial compliance requirements, it does not address other fuel sampling requirements. Section 63.1001 states, "you must also conduct fuel analyses according to §63.10008 and establish maximum fuel pollutant input levels" and includes specifics for handling single-fuel units. The commenter questions whether the EPA intended to require single-fuel sources to conduct initial and ongoing fuel sampling like the IB MACT approach since other sections appear to only require fuel sampling when burning a new fuel type.

Comment 29: In addition to the fuel sampling clarification, commenter 17716 also recommends that the EPA expand the exemption in section 63.10005(c)(5) to cover units that fire multiple fuel types or blends in the final rule. The section states that, fuel sampling and analysis are not required for single-fuel units using supplemental fuels that are used only for startup, shutdown or for maintaining flame stability.

Comment 30: Commenter 17775 requests that the EPA review and update the language regarding fuel analysis tests in section 63.10008 and Table 6 to ensure clarity and consistency. Proposed section 63.10008 requires fuel analysis tests according to the "procedures in paragraphs (b) through (e)" and Table 6. Paragraphs (c) and (d) specify minimum sampling procedure and compositing procedures. However, Table 6 also provides sampling methods that can be used in lieu of those in paragraph (c) and some of those procedures address compositing. The commenter requests that the language clearly state that any procedure identified in Table 6 can be used in lieu of procedures in paragraphs (c) and (d).

Comment 31: Commenter 17796 states that "What Are My General Requirements for Complying with this Subpart," paragraph (c)(2), clearly states that liquid oil-fired EGUs can demonstrate initial and continuous compliance using fuel analysis for HCl, HF and total HAP metals but does not indicate that Hg can be used in the fuel analysis to demonstrate compliance. The commenter states that non-Hg HAP metals and Hg are generally segregated from other parameters for compliance determinations and requests that the EPA address these constituents clearly and cohesively.

Comment 32: Commenter 17386 states that the fuel analysis provision appears to be in direct contradiction to the discussion of this topic in the preamble of the rule (FR page 25053 Column1}, which states (after the initial compliance demonstration by fuel analysis), "We are proposing that a source be required to recalculate the fuel pollutant content only if it burns a new fuel type or fuel mixture..."

Comment 33: Commenter 17718 requests that the EPA clarify the frequency of ongoing fuel sampling/analysis required for purposes of comparison with "the maximum fuel input values calculated during the last performance tests (if demonstrating compliance through performance stack testing)."

Comment 34: Commenter 17718 states that the establishment of fuel limits appears applicable only to facilities that choose to comply via fuel analysis. If facilities apply CEMS, accurate compliance can be determined at the emission point and, therefore, the fuel input becomes irrelevant. Additionally, there are numerous inaccurate section/paragraph references within the proposed regulatory language of 40 CFR 63.10011(b). The EPA should carefully review this section to properly link references to the appropriate sections and paragraphs.

Response to Comments 28 -34: The comments are moot because rule no longer requires fuel analysis for pollutants.

5. Subcategory comments.

Comment 35: Commenter 17843 supports fuel-based testing for compliance demonstrations by liquid oil-fired units, but not stack testing every other month. The commenter notes the following inconsistencies and clarity issues regarding liquid oil-fired units sections:

- It is not clear that the language at section 63.10006(p) applies to low emitting EGUs and it is difficult to understand how the timing set out in section 63.10006(o) follows in section 63.10006(p). The commenter suggests that sections 63.10006(f) and (g) should refer to Table 6 (Fuel Analysis Requirements), not 5 (Performance Stack Testing Requirements), which would have more clearly allowed liquid oil-fired units to use fuel analysis to demonstrate compliance. Commenter 16513 also states that this section is unclear and adds that it is unclear what the term "continue to meet" in section 63.10006(p) means in the context of section 63.10006(o).
- In section 63.10006(s), the opportunity to demonstrate compliance with the Hg, individual or total non-Hg HAP metals, HCl, or HF emissions limit based on fuel analysis seems broader than the liquid oil-fired limited use subcategory, but the description in the preamble (see (d) above) appears to limit the fuel analysis compliance option to liquid oil-fired units that operate a limited amount of time per year on oil and are inoperative the remainder of the year.
- Commenters 17843 and 17796 both note that under section 63.10006 "When must I conduct subsequent performance tests, fuel analysis or tune-ups?," it is clear that affected EGUs firing solid oil-derived fuel and coal-fired must demonstrate continuous compliance with either CEMS, or stack testing based upon the methodologies in Table 5, stack testing. It is not clear in this section what is required for liquid oil-fired EGUs. In subdivisions (f) and (g), based upon EGUs with or without non-Hg HAP metal controls, continuous compliance is demonstrated by either every other month or monthly, respectively, performance testing (stack testing) based upon Table 5. In the same section 63.10006 subdivision (s), continuous compliance can be based upon fuel analysis, which contradicts subdivisions (f) and (g). The general requirements state fuel analysis is acceptable for liquid oil-fired EGUs for the initial and continuous compliance options these issues and request continuous monitoring requirements for liquid oil-fired EGU should be rewritten for parity and clarity.

Response to Comment 35: The comments concerning fuel analysis for pollutants are moot because rule no longer contains this requirement. The rule has been revised to clarify compliance options for liquid oil-fired EGUs, and the rule continues to allow an EGU owner or operator to choose a compliance option, including quarterly emissions testing, use of CEMS, or, in certain circumstances, tune-ups or fuel moisture analysis.

Comment 36: Commenter 17843 requests that the language in sections 63.10006(o), (p) and (s) be updated to clearly state the monitoring requirements for oil-fired EGUs and to indicate that stack testing is not intended to be conducted every two months.

Comment 37: Commenter 17718 recommends that the EPA clarify whether the fuel analyses and procedures in section 63.10008 are only applicable to liquid oil-fired EGUs that desire to meet their applicable emission limits through fuel sampling.

Comment 38: Commenter 17796 recommends that the requirements for the oil-fired units subcategory be evaluated and revised for clarity with regard to initial and continuous monitoring parameters. For example, although section 63.10005, Testing, Fuel Analysis and Initial Compliance Requirements, subdivision (b) is clear that affected EGUs must demonstrate initial compliance with each of the applicable emission limits in Tables 1 and Tables 2 by conducting performance tests according to section 63.10007 and Table 5 and either conduct fuel analysis, set operating limits or conduct Continuous Monitoring System evaluations. It is not clear in subdivision (c) that liquid oil-fired EGUs may choose to demonstrate compliance with fuel analysis. Subdivision (c) begins with compliance that can be demonstrated by fuel analysis "except for those affected EGUs that meet the exemption in (c)(4) and (c)(5) and those affected EGUs that opt to comply with individual or Total HAP metals limits in Tables 1 and 2 which must comply by conducting a fuel analysis as described in paragraph (c)(1)." No mention is made to paragraph (c)(2) which refers to HF or (c)(3). The commenter requests that subdivision (c) and continuous monitoring requirements be rewritten for clarity, and that all language regarding oil-fired units be evaluated for consistency and clarity.

The commenter states that section 63.10006(s), the opportunity to demonstrate compliance with the mercury, individual or total non-mercury HAP metals, HC1, or HF emissions limit based on fuel analysis seems broader than the liquid oil-fired limited use subcategory. The commenter recommends that if it is not the EPA's intention to allow units other than liquid oil-fired limited use units to utilize a fuel analysis compliance mechanism, the EPA should clarify the language.

Comment 39: Commenter 17718 states that section 63.10011(b) makes reference to conducting fuel analyses and establishing maximum fuel pollutant input levels ." .as applicable." The commenter requests that the EPA clarify that the fuel sampling, analyses, and maximum input levels are only applicable to liquid oil-fired EGUs that choose to meet their emission limits through fuel sampling methodologies.

Comment 40: Commenter 17881 states that if compliance via fuel sampling and analysis is only available to liquid oil-fired units, then section 63.10021(a)(3) only applies to liquid oil-fired units, and the rule should clarify this point. Additionally, the commenter requests that the provisions of sections 63.10011(c), 63.10021 (a)(6) and 63.10022(a)(6) should also specify that the paragraph applies only to liquid oil fired units or possibly LEE.

Response to Comments 36 - 40: As mentioned elsewhere, the comments concerning fuel analysis for pollutants are moot because rule no longer contains this requirement. The rule has been revised to clarify compliance options for liquid oil-fired EGUs, and the rule continues to allow an EGU owner or operator to choose a compliance option, including quarterly emissions testing, use of CEMS, or, in certain circumstances, tune-ups or fuel moisture analysis.

Comment 41: Commenter 17174 states that the language in section 63.9983(b) for the natural gas-fired EGU exemption contradicts the preamble of the rule. The commenter suggests that EPA use the language in the preamble for the natural gas-fired EGU exemption in section 63.9983(b). Furthermore, the commenter states that the language does not clearly state the types of fuel-fired EGUs which are subject to this subpart. The commenter recommends that should be rewritten for clarity.

Comment 42: Similarly, Commenter 17881 notes that the preamble discussion is confusing and sheds no light on the purpose of section 63.9983(b). The preamble discussion could lead one to the conclusion that the proposed rule applies to all units other than natural gas-fired units (i.e., those units for which at least 90 % of the annual average heat over a 3-year period, or more than 85 % of the annual heat input in at least one year, is derived from natural gas).

Comment 43: Commenter 17881 states that the provisions of section 63.9983(b) are confusing because rule only applies to coal- and oil-fired EGUs, and the percentage of heat input supplied by natural gas is not relevant if the unit is not classified as a coal- or oil-fired EGU. The provisions of section 63.9983(b) state that EGUs which are not coal-fired or oil-fired EGUs and which combust natural gas for certain minimum percentages of the annual average (i.e., > 15 %) or 3-year average heat input (i.e., > 10 %) are exempt from the rule. In cases where coal-fired or oil-fired EGUs co-fire such fuels with other fuels, section 63.9983(c) already contains provisions on the relative amount of coal and/or oil firing (on a heat input basis) which would subject the unit to the requirements of the rule.

Response to Comment 41 - 43: We believe that the definitions in the final rule along with other edits related to situations where sources may "switch" source categories make the clarifications suggested by the commenter.

Comment 44: Commenter 17758 recommends that the language for coal-based compliance should be clarified. The commenter states that the most likely coal-based configurations able to comply with the EPA's proposed rule will 1) opt for the total PM limit and utilize PM CEMS for continuous filterable PM measurements; 2) employ some combination of wet or dry scrubbing, and/or DSI, for acid gas control and elect to use already installed SO_2 CEMS; and 3) directly monitor mercury using either a Hg CEMS or a sorbent trap monitoring system. For the above-described scenario in which either all of the regulated HAP or their surrogates are continuously monitored, the commenter states that no additional burdens (e.g., coal sampling, operating parameter limits, etc.) should be imposed. Although the commenter believes that the EPA does not intend to create additional burdens, the proposed rule is drafted is unclear and it is recommended that the language be updated for clarity.

Response to Comment 44: Although the agency is appreciative of the commenter's view that the agency does not intend to create additional burdens, the rule must be written with all EGUs in mind, not just the majority. As mentioned elsewhere, the rule has been revised not to require additional compliance information from those EGU owners or operators who choose to use CEMS or sorbent trap monitoring as the means for compliance determination.

Comment 45: Commenter 17881 recommends that section 63.10006(e) be updated to reduce confusion. The paragraph pertains to those solid oil-fired and coal-fired EGUs without either a PM CEMS or PM control device. On the surface, it is hard to imagine any coal or petroleum coke fired boilers being operated without PM controls, so it is assumed that this paragraph must apply exclusively to IGCC units. To eliminate any possible confusion, the commenter suggests that the EPA replace the term "solid oil-fired and coal-fired EGUs" with "IGCC unit" (Note that the definition of IGCC unit at section 63.10042 already incorporates the concept of solid oil or coal being used in the gasification process).

Response to Comment 45: The agency disagrees with the commenter, noting that the rule must be written to cover all possible control device scenarios, not just the ones believed to exist at the present time. As a result, no change to the rule has been made.

6. Operating limits comments.

Comment 46: Several commenters (17752, 17725, 17800) note that the rule contains conflicting language regarding how operating limits are established. Section 63.10011(d) refers to the average of three runs, while Table 4 of the proposed rule refers to the highest hourly average during the performance test. Commenter 17800 states that use of the "highest hour" makes no sense if the EPA is referring to Method 5 data, since runs are not measured in hours but in sample volume (and runs will be more than one hour). Both commenters recommend that the EPA provide a rationale for how a three-run performance test is sufficient to capture operational variability of a unit and revise the operating limits language to be consistent across both sections, as opposed to allowing for a 30 boiler operating days as done for the other HAP. Commenter 17725 recommends establishing a FPM limit as a surrogate for non-Hg metal HAP instead of TPM, which would do away with the need for a PM "operating limit."

Comment 47: Commenters 17681 and 17800 state that operating limits, including operating load limits and fuel limits, should not be established for units using CEMS for compliance because requirements to measure operating parameters are unnecessary and overly burdensome. For facilities using stack tests for compliance, the commenter recommends that the EPA allow sources to develop a CAM plan as an alternative to mandating operating limits, including operating load limits and fuel limits.

Comment 48: Commenter 17881 states that the procedures in Table 7 are not consistent with the provisions of section 63.10011(b)(6) or the definitions in section 63.10042. The commenter requests that, for Table 7, the EPA clarify that operating limits only apply in cases where CEMS are not used and does not apply for HF/HCl/Metals when you are demonstrating compliance with the surrogate standards. The commenter requests that consideration be given to the form of the DSI or ACI rates as an absolute mass will not work at reduced loads. For ACI, the rate has often been specified as lb ACI/mmACFM of flue gas.

Comment 49: Several commenters (17881, 17725, 18498) state that the limits for other operating parameters are inconsistent. Section 63.10042 defines the minimum operating parameters limits (minimum scrubber effluent pH, minimum pressure drop, minimum scrubber flow rate, minimum sorbent injection rate and minimum voltage or amperage) as 90 % of average value measured during the most recent performance test. However, Table 4 states that the parameters must be maintained "at or above the lowest 1-hour average" from the performance test. Commenter 18498 states that the "one-size-fits all" operating parameter limit approach should be revised to allow sources greater flexibility in defining representative operating parameters. Commenter 17881 requests the EPA must provide clarification as to how the operating limits are to be established.

Comment 50: Commenter 17718 states that the regulatory language seen in 40 CFR 63.10006 (a), (b), (d), (h) and (i) does not seem to allow for process improvements. As written, subsequent performance tests must be conducted "during the same compliance test period and under the same process (e.g., fuel) and control device operating conditions." Process improvements discovered after initial compliance testing could potentially allow for the same or better control of emissions yet move the control device operating conditions outside of what was established as the "operating limits" established per Tables 4 and 7 of the proposed rule. The commenter suggests that the "same process and control device operating conditions" language be removed from these regulatory sections to be similar to language proposed in 40 CFR 63.10006 (e), (f), (g), (j), (k), (l), and (m) where testing under those "same conditions" is not required.

Comment 51: Commenter 17718 notes that section 63.10022(a)(6) states that existing units with an ESP in an emission averaging option must "maintain the monthly fuel content values at or below the operating limit established during the most recent performance test. The commenter requests that the EPA clarify why the presence of an ESP would require monthly fuel content determinations and suggests that the reference should be removed from the proposed regulation.

Response to Comments 46 - 51: As mentioned elsewhere, the comments concerning control device operating parameters and fuel analysis for pollutants are moot because the rule no longer requires them. In addition, the Agency agrees that EGU owners or operators who choose to use CEMS as a compliance option need not conduct other monitoring, that the use of continuous operating parameters in existing CAM plans or due to permitting or other program requirements is an appropriate means of assuring compliance with this rule's emissions limits between emissions testing, and that a clarification on establishment of operating parameters for those EGU owners or operators who choose to use PM CPMS as a compliance option is needed; the rule now addresses each of those items.

7. Normal operating load.

Comment 52: Commenter 17174 states that section 63.10009(e) requires performance tests to be conducted at "maximum normal operating load." However, section 63.10009(g)(2)(vii) requires demonstration of compliance with each of the applicable emission limit(s) to be achieved under "representative operating conditions." The commenter requests that the EPA clarify this discrepancy and clearly define in section 63.10042 what constitutes maximum normal operating load or representative operating conditions.

Comment 53: Commenter 17731 states that the term "maximum normal operating load," section 63.10007(c), should be clarified and distinguished from "representative normal operating load."

Response to Comments 52 and 53: The agency has reviewed the commenters' concerns and revised the rule such that emissions testing is to occur at normal operating conditions. Moreover, if an EGU owner or operator wishes to demonstrate compliance under other than normal operating conditions, the rule requires emissions testing at those other conditions.

8. 30-day rolling averages.

Comment 54: Commenter 17821 has the following recommendations regarding 30-day rolling averages:

- Section 63-10010(b)(5) contains language that could be interpreted to mean that an O_2 monitoring system is required for compliance with these regulations. The last sentence of this paragraph references developing 30-day rolling averages from "hourly oxygen emissions data." Paragraph (b) of this section references using CO_2 monitoring. The commenter recommends that paragraph (5) of this section be modified to reference averaging either O_2 or CO_2 emissions data, if the EPA believes that O_2 andCO_2 are necessary.
- Section 63.10010(b)(5) also references using "all the hourly…emissions data" to develop 30-day rolling averages. This language could be construed to mean that both valid and invalid data should be used to develop long-term averages. The commenter recommends that paragraph (5) be modified to include language to specify that only valid hourly data should be used to develop 30-day rolling averages.
- Section 63.10010(c)(5)indicates that a 30-day rolling average for HCl should be developed; however the applicable engineering units are not specified. The commenter recommends that the EPA specify the engineering units that apply to the 30-day rolling average. Furthermore, this paragraph also references using "all the hourly HCl emissions data" to develop 30-day rolling averages. This language could be construed to mean that both valid and invalid data should be used to develop long-term averages. The commenter recommends that paragraph (5) be modified to include language to specify that only valid hourly data should be used to develop 30-day rolling averages.
- Section 63.10010 (e)(5) indicates that sources should develop 30-day rolling average for SO_2 but it does not specify the applicable engineering units. The commenter recommends that the EPA

specify the engineering units that apply to the 30-day rolling average. Furthermore, this paragraph also references using “all the hourly SO_2 emissions data” to develop 30-day rolling averages. This language could be construed to mean that both valid and invalid data should be used to develop long-term averages. The EPA should modify this paragraph to include language to specify that only valid hourly data should be used to develop 30-day rolling averages.

- Section 63.10010 (g)(5) indicates that a 30-day rolling average for particulate emissions should be developed; however, the applicable engineering units are not specified. The commenter recommends that the EPA specify the engineering units that apply to the 30-day rolling average. Furthermore, this paragraph also references using “all the hourly particulate emissions data” to develop 30-day rolling averages. This language could be construed to mean that both valid and invalid data should be used to develop long-term averages. The EPA should modify this paragraph to specify that only valid hourly data should be used to develop 30-day rolling averages.

Comment 55: Commenter 17681 notes an inconsistency between section 63.10010(g)(5) and Table 8. Section 63.10010(g)(5) states that 30-day rolling average is calculated as “the average of all of the hourly particulate emissions data for the preceding 30 boiler operating days.” In contrast, Table 8 states that the source is to convert “hourly emissions concentrations to 30 boiler operating mg/dscm values,” which suggests that compliance is assessed on the average of 30 individual daily values. Commenter 17681 also notes that the methods to calculate the 30-day rolling average is unclear and requests that the EPA clarify that a 30-operating day is based on the average of all applicable hours in the 30-day period.

Response to Comments 54 and 55: As mentioned elsewhere, the rule now allows CO_2 or O_2 CEMS to be used, clarifies that only valid hours are to be included in the 30 boiler operating day rolling average, identifies the reporting units as either pounds per heat input or pounds per electrical output, and clarifies that the 30 boiler operating day rolling average is based on the average of all valid hours in the preceeding 30 days of boiler operation.

9. Fuel mixtures and switches.

Comment 56: Commenter 17696 recommends that the EPA clearly state that performance testing on a “fuel mixture” does not require performance testing using coal of the same classification/common name that is provided by different suppliers, different mines or different seams. The commenter states that the proposal’s references to “fuel mixture” leave room for confusion even though the definition of “fuel type” (section 63.10042) is clear that individual fuel types received from different suppliers are not considered new fuel types. The EPA should clarify that, for example, if a subbituminous coal-fired unit has different suppliers of subbituminous coal, then the unit can conduct performance tests while burning any one of its suppliers’ subbituminous coal (or mixture of the different supplier’s subbituminous coals) and is not required to conduct performance tests using each supplier’s coal or to test using a blend of subbituminous coal from each of its different suppliers.

Response to Comment 56: The agency considered the commenter’s concern and disagrees with the commenter’s suggestion that the rule needs to offer additional clarification with respect to fuel switching with the same fuel type. The rule maintains that EGU owners or operators are to operate at normal operating conditions using normal fuels; if fuel conditions change, the rule requires the EGU owner or operator to conduct additional emissions testing. If an EGU owner or operator wishes to avoid having to be concerned about retesting based on fuel switching, he or she could use a CEMS option, rather than the emissions testing option, to demonstrate compliance.

Comment 57: Commenter 18034 requests that the rule should articulate which standard applies when a unit fuel switches or when a unit burns blends of different fuels. Although units may have been designed to burn coal with a heat content of less than 8,300 Btu/lb, several units can and may switch to coal with a heat content greater than 8,300 Btu/lb. Fuel blending and fuel switching are common practices utilized to minimize SO_2 emissions and the commenter recommends that the EPA take into consideration and encourage environmentally beneficial practices such as fuel blending and fuel switching.

Comment 58: Commenter 17781 recommends that the EPA clarify section 63.9982(d) regarding switching coal rank or fuel type by revising the language as follows:

> "An existing electric utility steam generating unit that has switched completely to burning a different coal rank or fuel type is considered to be an existing affected source under this subpart."

Response to Comments 57 and 58: The agency considered the commenters' concerns and disagrees with the commenters' suggestions. As mentioned elsewhere, the rule maintains that EGU owners or operators are to operate at normal operating conditions using normal fuels; if fuel conditions change, the rule requires the EGU owner or operator to conduct additional emissions testing. If an EGU owner or operator wishes to avoid having to be concerned about retesting based on fuel switching, he or she could use a CEMS option, rather than the emissions testing option, to demonstrate compliance. Moreover, the Agency sees no need to include the commenter's suggested language changes in the rule because such changes could be misconstrued as changing the current definition of modification.

Comment 59: Commenters 17808 and 17870 seek clarification on the compliance requirements for units that may change from being "natural gas-fired" to "fossil fuel-fired." A natural gas-fired generating unit may be forced to combust oil to maintain electric system reliability, and could suddenly change from being an unregulated natural gas-fired unit to a regulated fossil fuel-fired generating unit (if the EPA does not adopt the above-proposed definition for curtailment). Outside of curtailment situations, a dual-fired unit may also burn oil if prices are competitive relative to natural gas or for other reasons. The proposed rule is unclear with regard to how much time the EPA would allow a newly-designated fossil fuel-fired unit to schedule and perform its initial performance tests to demonstrate compliance with the applicable standards. Commenter 17870 recommends a period of 180 days from the date that a unit newly meets the definition of an affected fossil fuel-fired unit subject to the rule.

Response to Comment 59: Although the agency has considered the commenter's suggestions, the rule remains unchanged. An EGU owner or operator must remain cognizant of the definitions in the rule, especially, for this instance, the definitions of natural gas-fired electric utility steam generating unit and of oil-fired electric utility steam generating unit, along with rule requirements that trigger applicability and compliance dates.

10. SO_2 comments.

Comment 60: Commenter 18498 notes that for SO_2 CEMS, section 63.10021(a)(13) does not include the option to use the Part 75 certification and ongoing QA/QC requirements as allowed in section 63.10010(e). Commenter 17705 suggests that section 63.10021(a)(13)(ii) should include a cross-reference to section 63.10010 allowing use of 40 CFR Part 75 certified monitors to conduct SO_2 monitoring, with exceptions listed in section 63.10010 (e)(6). This cross-reference will help clarify that monitors following the requirements of 40 CFR Part 75 can be used in lieu of monitors following 40 CFR Part 60.

Comment 61: Commenter 17716 recommends that the EPA use the Part 75 text on linear check tests instead of the text section 63.10010(e)(6)(ii), which states that one “must perform the linearity check test required in appendix A to Part 75 on the SO_2 CEMS whether or not it has a span of 30 ppm or less.” The Part 75 exemption was developed on the basis that a linearity check “begins to lose its significance” at span values less than or equal to 30 ppm (63 FR 28032/28061 (May 21, 1998)).

Comment 62: Commenter 17714 requests that the EPA clarify the language placement of the SO_2 monitor at the outlet of the EGU in section 63.10010(e) to definitively state that it refers to placing the monitor in the stack downstream of the SO_2 control device for the EGU.

Comment 63: Commenter 17821 notes an unintended conflict between sections 63.10010 (e) and (e)(1). In paragraph (e), the EPA clearly states that sources operating an SO_2 monitoring system for purposes of compliance with 40 CFR Part 75 may continue to do so under these proposed rules. However, in paragraph (e)(1), the rule defines and limits the operation and quality assurance to specific sections of 40 CFR Part 60 without referencing the prior alternative to operate an SO_2 CEMS under 40 CFR Part 75. The commenter recommends that the EPA modify paragraph (e)(1) of this section to clearly state the EPA’s intended use of 40 CFR Part 75 for applicable sources.

Response to Comments 60 – 63: As mentioned elsewhere, the rule has been clarified to allow use of Part 75 procedures for those CEMS subject to the rule and used in the Acid Rain Program. Moreover, the rule has been clarified so that CEMS are to be placed at the outlet of an EGU.

Comment 64: Commenter17881 states that none of the definitions for the term Er (regarding rolling emission averages in Equations 1 through 5) mention SO_2, but there do not seem to be any prohibitions from averaging SO_2 emission rates (assuming that all units included in the averaging plan would need to be eligible to use the SO_2 surrogate). The commenter suggests that SO_2 be added to the list of pollutants included in the term Er.

Comment 65: Commenters 18498 and 17725 recommend that the EPA add a subsection to section 63.10010(e), which clarifies that bias adjusted data and Part 75 missing data shall not be used in calculating the 30 boiler operating day average SO_2 emission rate. Although this is discussed in appendix A to subpart UUUUU for Hg CEMS (Reference appendix A sections 1.4 and 4.1.2.4), this data exclusion is not clearly stated for SO_2 CEMS.

Response to Comments 64 and 65: The agency agrees with the commenter that SO_2 should be included in all equations with the term E_r, and the rule has been revised to correct that omission. The agency disagrees with the commenter that additional language concerning acid rain program requirements is necessary for this rule. Should an EGU owner or operator lack SO_2 hourly emissions data, no other data would be valid and thus eligible for inclusion in a 30 boiler operating day rolling average. Moreover, the EGU owner or operator would have to report the period of missing data to the Agency for further review and potential enforcement action.

11. Testing guidelines and timeline comments.

Comment 66: Commenter 17821 recommends that the EPA review the inconsistencies regarding section 63.10030(a) and section 63.10030(d). Section 63.10030(a) requires submission of all of the notifications in section 63.7(b) and section 63.9(e). Proposed Table 10 also identifies section 63.7(b) and section 63.9 as applicable. Sections 63.7(b) and 63.9(e) require notification of “intent to conduct a performance test at least 60 calendar days before the performance test” is initially scheduled to begin.

However, proposed section 63.10030(d) requires submission of a “Notification of Intent” to conduct a performance test, but “at least 30 days before the performance test is scheduled to begin.” Requiring submission of two identical notices at different times makes no sense. If the EPA intends to allow submission of the notice only 30 days before the test, the EPA should identify as “inapplicable” the inconsistent notice requirements. If the EPA intends to require submission 60 days before the test, the EPA must remove the redundant requirement in section 63.10030(d).

Response to Comment 66: The agency agrees with the commenter’s concerns, and the rule will be revised to have a consistent submission date for the notification of intent to conduct performance testing.

Comment 67: Commenter17758 requests that the EPA specify whether the time ranges provided for testing guidelines in section 63.10006(n) refer to calendar or operating days to avoid confusion. The commenter recommends that the preferred option should be in terms of operating days or operating quarters since these terms are used routinely by utilities to manage emissions program schedules and give utilities the flexibility necessary for performing the required tests.

Response to Comment 67: The time ranges in the rule refer to calendar, not operating, days.

Comment 68: Commenter 17821 requests that the EPA either identify when EGUs are not required to submit a Notice of Compliance Status or revise the section to make clear that all EGUs must submit such a Notice. Proposed section 63.10031(e) requires EGUs to submit a “Notification of Compliance Status” according to section 63.9(h)(2)(ii), “[i]f you are required to conduct an initial compliance demonstration as specified in § 63.10011(a).” However, under proposed section 63.10005(a) all EGUs “must demonstrate initial compliance with each of the applicable emission limits in Tables 1 or 2” Moreover, section 63.9(h) on its face applies to each affected source when it becomes subject to a relevant standard.

Response to Comment 68: The agency disagrees with the commenter’s suggestion that an EGU owner or operator is unable to determine whether or not he or she will need to provide notice of compliance status based on the results of initial performance testing, whether for CEMS or for stack tests. The rule language has not been revised.

Comment 69: Commenter 17821 requests that the EPA issue a rule that clearly articulates the various compliance demonstration options. The commenter also notes that under paragraph (3), the Notification of Compliance Status must include “[i]dentification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing and fuel analysis; performance testing with operational limits (e.g., CEMS for surrogates or CPMS); CEMS; or sorbent trap monitoring system.” The listed options do not appear to correspond with the rest of the proposed rule. For example, proposed section 63.10011(b) appears to require all EGUs that conduct performance testing to perform fuel analysis and to set operational limits.

Response to Comment 69: As mentioned elsewhere, much of the commenter’s concern is moot because rule no longer requires fuel analysis for pollutants or operational limits for control device parameters. Although the Agency disagrees with the commenter’s assertion that the rule is unclear with respect to compliance demonstration options, the rule has been revised to further clarify the options available to EGU owners or operators.

Comment 70: Commenter 17881 states that the language in section 63.10009(j)(2) regarding each affected and non-affected unit meeting the most stringent emission limit is confusing, as non-affected units do not have any applicable emission limits under the proposed rule. The commenter questions whether the intent is to simply allow the common stack to comply with the most stringent emission limit that applies to any of the affected EGUs that exhaust to the common stack. If so, the commenter recommends that the regulatory language should more clearly reflect this intent.

Response to Comment 70: The agency disagrees with the commenter's concern that the language regarding appropriate emissions limits from differing units sharing a common stack is confusing. The rule retains language requiring an EGU owner or operator who chooses to use emissions averaging to shut down units not subject to the rule during performance testing or to operate all units sharing a common stack at or below the most stringent emissions limit to which any individual EGU is subject, whether or not such individual EGU is subject to this rule. Should an EGU owner or operator remain concerned about meeting the rule's requirements, he or she could choose not to use emissions averaging.

Comment 71: Commenter 17881 requests that section 63.10021(a)(4) be revised for clarity because EGUs without HCl CEMS are required to test monthly or bimonthly. Thus, the tests would already be conducted within the frequency (60 days) specified in the paragraph.

Response to Comment 71: The comment is moot, for the rule now requires EGU owners or operators who choose to use emissions testing as the compliance option for acid gas emissions limitations to conduct testing every quarter.

Comment 72: Commenter 17718 requests the following modifications to improve the clarity regarding performance testing:

- Section 63.10006(o) states that the ability to decrease the frequency of performance testing from annual (or more frequent) is available if testing shows emissions at or below 50 % of the emission limit and if there are "no changes in the operation of the affected source or air pollution control equipment that could increase emissions." The commenter requests that the EPA provide clarification on what constitutes "no change" and what information would be needed to successfully pass these criteria. For example, it is unclear whether the "no change" provision applies to the affected unit and is not inclusive of the entire facility.
- Section 63.10007(c) requires performance tests to be conducted "while burning the type of fuel or mixture of fuels that has the highest content..." The commenter recommends that the EPA clarify whether reference to "type of fuel" simply means that if bituminous coal is typically burned, then bituminous coal is to be used during the test. This section does not appear to require a determination that the highest chlorine (or other constituent) content bituminous coal be used during the test. The commenter also suggests a clarification that "special fuels" are not required or expected for the performance test.
- Section 63.10007(f) states that "(p)erformance tests shall be conducted under such conditions as the EPA Administrator specifies to the owner or operator...." The commenter recommends that the EPA clarify whether it will specify when and how performance testing is to be completed, beyond what is already proposed in other sections of the regulatory language. If the specifications are the same the commenter recommends that section 63.10007(f) should be removed.

Response to Comment 72: The agency disagrees with the commenter's suggestion that specific criteria be enumerated concerning possible impacts of EGU operation on emissions for those EGU owners or operators who choose to seek LEE status. Those EGU owners or operators are in the best position to understand what changes could cause impacts on emissions and remain responsible for EGU emissions;

should an EGU owner or operator be uncomfortable meeting the LEE eligibility requirements, he or she need not apply. As mentioned elsewhere, the comment concerning highest pollutant content in fuel is moot, as fuel analysis for pollutants is no longer required. Finally, as mentioned elsewhere, the rule now requires emissions testing be performed at normal operating conditions.

Comment 73: Commenter 17718 requests that EPA clarify whether section 63.10009(c) requires that a "pre-test" be conducted so that a comparison can be made between a "30 day after" value and the initial compliance test. Section 63.10009(c) states that, "…the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on […] or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on…." If a pre-test is required, the EPA should specify the notification and submittal requirements for such a test.

Response to Comment 73: The rule has been revised so that an EGU owner or operator who chooses to use emissions averaging must be able to demonstrate compliance on a 30 (or 90) boiler operating day rolling average basis, which means that those owners or operators will need to ensure their existing units have at least one set of 30 (or 90) boiler operating day average values if CEMS are used for compliance determination and at least one completed emissions test with test results if emissions testing is used for compliance determination by 180 days after the effective date of this rule. Should an EGU owner or operator find these requirements to be of concern, he or she should choose not to use the emissions averaging option.

12. Other comments.

Comment 74: Commenter 17711 states that the word "sources" as used in the last clause of sections 112(d)(3)(A) and (B) is ambiguous and, therefore, susceptible to reasonable interpretation. As the EPA explains in the preamble, the word "sources" might be construed to refer to all sources in the given category or subcategory. However, the word "sources" in the first clause of sections 112(d)(3)(A) and (B) clearly refers to the sources for which the EPA has emissions information. Notably, the second use of the word "sources" in section 112(d)(3)(A) also clearly is a reference to sources for which the EPA has emissions information. So, it is reasonable to conclude that Congress intended the word "sources" to have a consistent meaning for all purposes under these provisions. In other words, the reference "30 or more sources" at the end of section 112(d)(3)(A) and "fewer than 30 sources" at the end of section 112(d)(3)(B) reasonably should be construed as a reference to sources for which the EPA has emissions information. This interpretation avoids the "absurd results" described above and allows for the EPA to naturally reconcile the application of sections 112(d)(2)(A) and (B) such that the number of sources for which the EPA has emissions information in a given category or subcategory dictates whether sections 112(d)(2)(A) or (B) should apply.

Response to Comment 74: The EPA does not agree with the commenter's interpretation. When Congress qualifies a word in one place but not others in the same section, the more reasonable inference is that it intended the qualification to apply only to that one instance.

Comment 75: Commenter 18034 supports the proposed emissions averaging approach; however, the EPA uses the term "applicable regulatory authority" exclusively in the context of submission, review, and approval of the emissions averaging implementation plan, such as in section 63.10009. Sources may incorrectly believe that the state regulatory authority is responsible for review and approval the emissions averaging plans even if the state has not received delegation from the EPA for the specific NESHAP rule. The commenter states that it is unnecessary for the EPA to use a separate term within the emissions averaging section. If a state accepts delegation of the final version of the proposed new subpart UUUUU, using the term "administrator" would apply equally for the emissions averaging provisions as it does to the other provisions of the rule. If a state has not received delegation for the NESHAP rule, not only would the state have no authority to issue an approval under section 63.10009(g), the state is under no obligation to review the plans on the EPA's behalf. The commenter recommends that the EPA should use the standard term of "the administrator" used elsewhere in the proposed rule to avoid confusion.

Response to Comment 75: The agency agrees with the commenter's suggestion and has revised the rule.

Comment 76: Commenter 17174 suggests the following areas which would benefit from additional review and clarity.

- Section 63.10009(a) states "you may demonstrate compliance by emission averaging among the existing EGUs in the same subcategory, if your averaged emissions for such EGUs are equal to or less than the applicable emission limit" However, section 63.10009(e)(l) states, "You must use equation 1 of this section to demonstrate that the PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from all existing units participating in the emissions averaging option do not exceed the emission limits in Table 2." The commenter recommends that the same wording be used in both sections in order to avoid confusion.
- Section 63.10009(e)(1) requires a facility to use Equation 1 to demonstrate compliance with PM, HF, SO_2, HCl, non-Hg HAP metals or Hg emissions, by using the emission rate as determined during the most recent performance test and the maximum rated heat input capacity. The commenter requests that the EPA clarify what constitutes the maximum rated heat input capacity of a utility boiler due to the variability in reported heat input ratings for utility boilers.
- Section 63.10009(g)(2) states that, "If affected units from nonaffected units vent to the common stack, the units from nonaffected units must be shut down or vented to a different stack during the performance test.," however it is unclear as to how one can have "affected units from nonaffected units." The commenter suggests the phrase be evaluated and rewritten for clarity.
- Although section 63.10009(g)(1) states that implementation plan "must" be submitted no later than 180 days before the facility intends to implement the plan, section 63.10009(g) indicates that implementation plan submittal is only necessary "upon request." The commenter recommends that the requirement to submit an implementation plan for emission averaging compliance should be evaluated and edited for consistency across sections. Commenter 17821 also seeks clarification regarding the discrepancy between sections.
- Section 63.10021(a)(16)(vii) should clarify whether performance tune-ups needs to be submitted electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT), as required in other parts of this section (63.10021(a)(11) and (17)).

Response to Comment 76: Although the agency notes that the applicable emissions limit is the limit obtained from Table 2 (or in the case of Hg from the EGUs designed for coal ≥ 8,300 Btu/lb subcategory, the limit given in §63.1009(a)(2)), the rule has been revised to be consistent. The agency does not agree that additional clarification on maximum rated heat input capacity is needed; EGU owners or operators should use the values submitted as part of the ICR process or as part of the acid rain program. The rule has been revised such that the sentence of concern now begins as "If emissions from affected units and from nonaffected units…" The rule has been clarified so that an averaging plan need only be submitted if requested by the Administrator. As a performance tune-up is a performance test, and the rule already requires performance test results to be submitted electronically using the CDX, no additional clarification language is needed.

Comment 77: Commenter 17716 requests the following corrections and clarifications:

- The rule does not include the equations for calculating PM or HCl mass emissions. Appendix A only includes equations for Hg. Commenter 17725 also notes this issue.
- Section 63.10009 (j)(3) references opacity requirements, however no opacity operating limits have been introduced as part of the rule. Commenters 17725, 17775, 18498-A2, 19120-A1and 18014 also took notice and have requested that the issue be addressed.
- Section 63.10010(b)(5) should be revised to include CO_2. For example, "… the average of all of the hourly oxygen *or carbon dioxide* emissions data for the preceding 30 boiler operating days."

Response to Comment 77: As mentioned elsewhere, Table 5 describes how mass emissions can be calculated. The rule no longer contains opacity requirements, which were included in the proposal in error. As mentioned elsewhere the rule has been revised to include CO_2 as well as O_2 measurements.

Comment 78: Commenters 17675 and 17718 request that the reference in section 63.10010(a)(4) to "paragraph 2.1 of this section" does not specify if it is referring to appendix A or another paragraph 2.1. The commenter s recommends that the rule clearly state the proposed monitoring methods for stacks on units with main and bypass stacks.

Response to Comment 78: The agency agrees with the commenter, and the rule has been revised to clarify installation requirements.

Comment 79: Commenter 17681 requests that the EPA further explain what constitutes sufficient monitoring for control devices in section 63.10009(g)(2)(vi)(B).

Response to Comment 79: As mentioned elsewhere, this comment is moot for the rule no longer requires monitoring of control device operational parameters.

Comment 80: Commenter 17730 states that the requirement to optimize the flame in the boiler and optimize the emissions of CO and NO_X lacks definition and needs explanation prior to the rule being finalized in order to comment.

Response to Comment 80: Although the agency disagrees with the commenter's suggestion that the flame optimization requirements need additional explanation, the rule has been clarified with respect to these requirements.

Comment 81: Commenter 17756 requests that the EPA clarify the language regarding "dry flue gas technology." The commenter states that the rule does not clearly indicate whether "dry flue gas technology" includes both dry scrubbers and dry sorbent injection. The commenter recommends that the EPA revise the language to specify that dry sorbent injection is an acceptable dry desulfurization technology.

Response to Comment 81: We believe that the definition in the final rule clearly indicates that both "dry scrubbers" and "dry sorbent injection" are included in "Dry flue gas desulfurization technology."

Comment 82: Commenter 18023 states that to provide efficient application of the proposed rule, 4.1.3 Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems should state that "Monitors that have been certified and quality assured to meet the requirements of 40 CFR Part 60 and/or 40 CFR Part 75 are acceptable for the purpose of calculating and reporting emissions without any additional certification or quality assurance."

Response to 82: In the final rule, section 4.1.3 of Appendix A states that the flow rate, diluent gas, and moisture monitoring systems that are used to convert Hg concentrations to units of the standard must be certified according to 40 CFR Part 75. This is necessary, since all of the CEMS data will be collected using the ECMPS system. Section 63.10005(d) specifies that if a continuous monitoring system has been previously certified under another State or Federal program and is continuing to meet the on-going QA requirements of that program, no additional performance evaluations of the monitoring system are required for Subpart UUUUU, provided that the applicable requirements of §§63.10010(b) through (h) are met.

Comment 83: Additionally, commenter 18023 states that section 3.2.1.4.2 is in conflict with section 3.1.7 where span value is defined but does allow rounding off the span value to the next highest integer multiple of 10. This would essentially restrict the span value to either 2 μg/m3 or 10 μg/m3. The rule should allow the user to set the span value anywhere between 2 and 10 μg/m3 as long as that range falls within acceptable limitations of the NIST traceable calibrator.

Response to Comment 83: The final rule provides sources with greater flexibility in setting the span value of the Hg monitor. The Hg concentration corresponding to the standard is doubled and then rounded off to either: (a) the next highest integer; (b) the next highest multiple of 5 $\mu g/m^3$ or; or (c) the next highest multiple of 10 $\mu g/m^3$.

Comment 84: Commenter 17881 states that section 63.10011(c)(5) should clarify whether compliance can be based on all HAP metals in aggregate or individual metals.

Response to Comment 84: As mentioned elsewhere, this comment is moot for the rule no longer requires fuel analysis of pollutants.

Comment 85: Commenter 17718 states that within the proposed regulatory language seen in 40 CFR 63.10005(l), it is mentioned that a "default diluents gas concentration value of 10.0 % O_2 or the corresponding fuel-specific CO_2 concentration" are to be used during periods of startup or shutdown when calculating emissions in units of "lb/MMBtu" or "lb/TBtu." The EPA should clarify how to calculate the "corresponding fuel-specific CO_2 concentration."

Response to Comment 85: As mentioned elsewhere, this comment is moot for the rule no longer requires emissions limits during periods of startup or shutdown.

Comment 86: Commenter 17795 requests that the EPA make the following revisions:

- In section 63.10005(k) on start-up and shutdown default values, the commenter requests the following language be added: "For those CEM systems that measure on a wet basis use of the moisture estimation as specified in 40 CFR 75 §75.11 (b) shall be acceptable for this provision."
- Also in section 63.10005(k) on start-up and shutdown default values, the commenter requests the following reference equations be added: 40 CFR 75, Appendix F, equations F-14a and F-14b.
- In section 63.10010 (b), the commenter requests the following language be added: 40 CFR 75 QA/QC is sufficient to meet the CO_2/O_2 requirements of this regulation.
- In section 63.10010 (e)(6)(iii), the commenter requests that the reference to a fourth level needs

to be removed because there is no additional benefit or reason to run four gases during a linearity. This additional calibration level will not make the system any more accurate.

Response to Comment 86: As mentioned elsewhere, the comments are moot, for the rule no longer requires numerical emissions limits during periods of startup or shutdown, the rule allows use of Part 75 quality assurance requirements for those monitors that are also used in the acid rain program, and the reference to a fourth level was removed from the rule, even though it was an optional requirement.

Comment 87: Commenter 17714 recommends that the definitional language regarding "monitoring system malfunction" be moved into the definition area of the rule identified as section 63.10042 since it appears to be more of a definition than a requirement.

Response to Comment 87: The final rule will include a definition of monitoring system malfunction in the definitions section of the rule. That definition will mirror the definition for monitoring system malfunctions found in the proposed rule.

Comment 88: Commenter 17881 requests the following clarifications and revisions:

- Information regarding the unit or stack operating time [7.1.2.2] is not needed in order to calculate the Hg emission rate in units of lb/GWh, nor is it needed to calculate the lb/TBtu emission rate. Thus, the commenter requests that the requirement to collect this data be deleted.
- The commenter also requests that the EPA clarify that the hourly gross unit load [7.1.2.3] is only needed for those units which are attempting to demonstrate compliance with a lb/GWh Hg emission limit.
- Information regarding the hourly heat input rate [7.1.2.4] is not needed to support the lb/GWh Hg emission rate calculations. The use of fuel factors in conjunction with the Method 19 equations allow the determination of a lb/TBtu emission rate without the need to determine the hourly heat input rate. Thus, the requirement to collect this data should be deleted.
- In the context of the lb/TBtu Hg emission rate determination, the F-factor is not used to calculate the heat input rate. Thus, the commenter requests that section 7.1.2.6 should be revised as follows: "The F-factor used to calculate the lb/TBtu Hg emission rate, consistent with section 6.2.1.2." Further, the EPA should clarify that this information is only needed for those units which are attempting to demonstrate compliance with a lb/TBtu Hg emission limit (i.e., it is totally unnecessary for lb/GWh calculations).
- The commenter disagrees with the assertion in section 7.1.5 that volumetric flow rate records are required for purposes of determining lb/TBtu emission rates pursuant to section 6.2.1. None of the referenced Method 19 Equations (i.e., 19-1 – 19-9) rely on volumetric flow rate; rather, these equations rely on pollutant and diluent concentrations, fuel factors, and in some cases, flue gas moisture content. Thus, the EPA should clarify that volumetric flow rate measurements are only required for those units relying on sorbent trap monitoring systems and/or conducting lb/GWh mercury emission rate calculations.
- Section 7.1.5.2.5 requires the reporting of hourly PMA, however the commenter states that the requirement is not appropriate when missing data substitution is being prohibited.
- Section 7.1.7 contains provisions related to diluent gas records in cases where compliance is being demonstrated on a lb/TBtu basis. Section 7.1.7.1 currently states that CO_2 or O_2 concentrations are needed "in order to calculate hourly heat input values." The commenter states that the preceding statement is incorrect, as the diluent gas values are being used to allow the direct calculation of lb/TBtu emission rates based upon additional Hg concentration data and appropriate fuel factors. The cited text in section 7.1.7.1 should be deleted. As noted for similar

provisions within appendix A, section 7.1.7.2.5 relates to hourly PMA records and should be deleted.
- The monitoring plan reporting time lines also do not align with the related reporting provisions in 40 CFR Part 63, subparts A and UUUUU. The EPA must carefully review the two sets of reporting provisions and clearly reconcile any differences between the provisions.

Response to Comment 88: The agency has reviewed the commenter's suggestions and in some cases revised Appendix A of the rule. The rule retains requirements for collecting operating time and gross unit load; EGU owners or operators who do not need these values to determine their unit's compliance need not collect these data. Rule text has been revised to remove hourly heat input rate from section 7.1.2.4, as well as section 7.1.2.6. The rule has been revised so that section 7.1.5 refers only to volumetric flow from EGUs that use sorbent trap monitoring systems and that percent monitoring availability (PMA) is no longer included. The language in section 7.1.7.1 has been revised "…to convert Hg concentrations to units of the standard." Finally, the agency believes the reporting time lines are now consistent.

Comment 89: Commenter 18034 states that section 63.10005(l) addresses the use of default O_2 and CO_2 concentrations for input-based emissions calculations and the default power production rate for output-based emissions calculations but does not explain what pollutant concentrations should be used. The commenter requests that the pollutant concentrations be clearly stated. The commenter also requests that the EPA revise the rule to address the calculation of emissions during a malfunction.

Response to Comment 89: As mentioned elsewhere, this comment is moot for the rule now requires work practice standards, not emissions limitations, during periods of startup or shutdown.

Comment 90: Commenter 18034 states that provisions in the affirmative defense rules need clarification or appear to be contradictory:

- Section 63.10001(a)(4) unnecessarily requires additional conditions to meet an affirmative defense to bypass a control device. In some circumstances, the bypass may be the most appropriate temporary implementation while correcting or repairing a condition of upset, since the upset may be with the control device itself. All actions required to meet an affirmative defense are sufficiently listed in the other provisions of section 63.10001(a) and must be met, including those actions designed to minimize emissions.
- Section 63.10001(a)(7) lists a requirement that "All actions in response were properly documented by properly signed contemporaneous operating logs," but does not define or accurately describe what would fulfill that requirement.
- Section 63.10001(a)(9) requires "a written root cause required to determine, correct, and eliminate the primary cause of the malfunction." This inevitably leads to an owner or operator attempting to describe a preventative action to an event that (by definition of one of the criteria) was not preventable.

Response to Comment 90: We believe the language is clear, not contradictory in nature, and provides an owner or operator a systematic and thorough approach for establishing an affirmative defense in the event of a malfunction that results in an exceedance of a standard. Many of the conditions were modeled after the conditions of the affirmative defense in the EPA's SIP SSM policy, which several states have adopted into their SIPs. We do not have any indication that parties to enforcement proceedings have had any significant difficulties applying the terms of these SIP affirmative defenses. (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)). Other conditions were modeled after a Federal Implementation promulgated by EPA. ((40 CFR 50.1312). The 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 EPA notes that the purpose of the root cause analysis is to determine, correct, and eliminate the primary cause of the malfunction and that the root cause analysis itself does not necessarily require that the cause be determined, corrected or eliminated. However, in most cases, the EPA believes that a properly conducted root cause analysis will have such results.

Comment 91: Commenter 18498 states that section 63.10010(b)(5) should be revised to include CO_2. For example, the commenter recommends that the language be amended to state:

> " ... the average of all of the hourly oxygen or carbon dioxide emissions data for the preceding 30 boiler operating days."

Comment 92: Commenter 18498 notes that section 63.10021 (a)(10)(ii) does not include a reference to CO_2 records.

Response to Comments 91 and 92: As mentioned elsewhere, the rule now includes carbon dioxide as well as oxygen, where oxygen is referenced.

Comment 93: Several commenters (17730, 17758, 17800) state that several provisions indicate that the requirements apply "as applicable," but few provisions clearly state to which EGU subcategory or to which option the requirement applies. For example, the overuse of ''as applicable" makes it difficult for the regulated source, or the state agency that will likely implement the program, to fully understand the requirements or demonstrate compliance with the chosen option. Commenter 17758 recommends that the EPA update the regulatory language to be consistent with its intent (e.g., unnecessary parameter limits which are not meant to apply when CEMS are used). The commenter further states that requiring excessive testing is inconsistent with EO 13563, as discussed elsewhere in these comments, which requires agencies to tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives.

Response to Comment 93: The agency disagrees with the commenters' suggestions. An EGU owner or operator who does not have applicable requirements is not subject to the provisions of the rule, e.g., an owner or operator who chooses to use CEMS as the compliance demonstration method is not subject to the frequent emissions testing compliance demonstration method. Apart from some clarification, the rule remains unchanged. As mentioned elsewhere, the rule no longer requires separate operating parameter monitoring from emissions control devices if CEMS are used as the compliance demonstration method. Although the emissions testing frequency has been reduced to quarterly, it remains consistent with supplying the information necessary to show compliance with the emissions standard. Should an EGU owner or operator find the emissions testing compliance method too burdensome, he or she should choose from among the other options for demonstrating compliance with the emissions limits.

Comment 94: Similarly, commenter 17800 states that due to the incorrect references to sections, incorrect citations and many other inconsistencies and misstatements within the proposed rule, it is difficult for the commenter to evaluate what is needed to comply and determine the best plan for compliance with this rule. The commenter requests that remove the many inconsistencies noted before sources are expected to justify the expenditures associated with compliance to its shareholders, its rate payers and its regulators such as the public service commission.

Response to Comment 94: As mentioned elsewhere, the rule has been revised to remove inconsistencies based on the Agency's review and commenter's suggestions.

Comment 95: Commenter 17909 states that the non-Hg metal HAP rules and compliance provisions portion of the proposed rule are indiscernible. Despite diligent, protracted study of the rule, participation in many, many conference calls and discussions with consultants, lawyers and the EPA staff, the commenter is unable to follow the rationale in the rule and therefore cannot apply the requirements to our affected source, plan for compliance or effectively comment on the proposed rule.

Response to Comment 95: Although the agency remains concerned that an EGU owner or operator claims difficulty understanding non-Hg metals rule options, the rule's flexibility in that regard appears to be understood, if not welcomed, by a large majority of commenters. Basically, an EGU owner or operator chooses a PM emissions limit, or individual non-Hg metals emissions limits, or a total non-Hg metals emission limit and demonstrates compliance based on that choice. Depending on the emissions limit, compliance options range from frequent emissions testing to use of PM CPMS to use of PM CEMS. Notwithstanding a few clarifications as discussed elsewhere, the rule maintains this flexibility. The commenter should contact the Agency if he or she remains confused as to the rule requirements.

Comment 96: Commenter 17254 urges the EPA to re-propose the rule to address statistical errors in the calculation of the proposed emission standards for Hg. Commenter cannot comment meaningfully on the rules until we know what standard the agency ultimately will propose.

Response to Comment 96: We have corrected the errors noted during the public comment period as soon as they were brought to our attention and believe that commenters had sufficient review time with the corrected values to provide meaningful comment. Consequently, the EPA does not believe that reproposal is necessary or required.

Comment 97: Commenter 17689 states that the EPA construes "the requirements of the act" to mean only acid rain control when evaluating effects of other CAA program EGU emission reductions on EGU HAP emissions. The language here is clear and unambiguous: "requirements of the act" cannot be read to include only acid rain control.

Response to Comment 97: To the extent that EGUs are subject to other control requirements established by states and tribes as part of their strategies to attain the NAAQS, these are not "requirements of the act." Similarly, requirements established as a result of specific new source permitting are in compliance with CAA-mandated programs but are not requirements of the act. The EPA did not state that the only requirement of the CAA contemplated in section 112(n)(1)(A) was the Title IV Acid Rain Program.

13. Reference and numerical corrections.

Comment 98: Commenter17796 notes that the Hg limit in the preamble is a typo and should read 0.0007 lb/GWh.

Response to Comment 98: The limits in the final rule have been reanalyzed and corrected.

Comment 99: Commenter17848 notes that the preamble contains an error in the output-based limit for Hg. The rule text indicates that the emission limit should be 0.008 lb/GWh, [however Table 1 indicates that it is 0.0008lb/GWh].

Response to Comment 99: The limits in the final rule have been reanalyzed and corrected.

Comment 100: Commenter 17881 agrees with the intent of section 63.10005(l) but notes that the proposed rule erroneously identifies this paragraph as 63.10005(1).

Response to Comment 100: The comment is moot because the rule now requires work practice standards, not emissions limitations.

Comment 101: Commenter17655 recommends that the paragraphs (p) and (q) in section 63.10006 be renumbered as (o)(1) and (o)(2) because they are not free-standing but instead within the context of (o). The commenter also recommends that if these changes are made, the references to paragraphs (p) and (q), such as section 63.10006(n) be updated for consistency.

Response to Comment 101: The rule has been revised to consolidate the LEE requirements.

Comment 102: Several commenters (17696, 17718, 18037, 17821) note incorrect cross references in the text of the proposed rule. For example, section 63.10006(r) states "If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to §63.10007. Each performance tune-up specified in § 63.10007 must be no more than 18 months after the previous performance tune-up." Section 63.10007 addresses only performance testing. Commenter 17718 states that if "performance tune-ups" is the correct term, it appears that section 63.10021(a)(16) would be the more accurate section reference.

Response to Comment 102: Although the agency believes a tune-up serves as the performance test for certain EGUs for certain pollutants, the rule has been revised to describe the tune-up as a performance tune-up.

Comment 103: Commenter17174 notes the following editorial issues:

- The last paragraph of section 63.10005(k) on start-up and shutdown default values for calculations is numbered as (1).30 but should be labeled as (4) to continue the numbering of the section. Commenters 17775 and 17795 also note this incorrect numbering.
- The word "limit" is missing at the end of the last sentence of section 63.1 0011(b)(6)(iv).
- Section 63.10011 (c) states "and follow the procedures in paragraphs (c)(1) through (c)(7) of this section." however there are only 6 paragraphs in section 63.10011 (c). Commenter 17881 also notes this inconsistency.

Response to Comment 103: As mentioned elsewhere, the comments are moot because rule no longer requires emissions limitations during periods of startup or shutdown, monitoring of control device operational parameters, or fuel analysis for pollutants.

Comment 104: Commenter17718 states that the reference in section 63.10010(b) to appendix A ."..in lieu of procedures in paragraphs (a)(1) through (a)(3) below...." is inaccurate because they do not pertain to O_2 and CO_2 monitors. The EPA likely needs to correct this reference to (b)(1) through (b)(5).

Response to Comment 104: The cross-reference to paragraphs (a)(1) through (a)(3) was clearly incorrect, and should have been (b)(1) through (b)(5), as noted by the commenter. Note, however, that in the final rule, the Agency has removed the Part 60 certification and QA alternative for diluent gas monitors, since all of the CEMS data will be collected using the ECMPS system. Section 63.10010(b) of the final rule specifies that the CO_2 or O_2 monitors must be certified and quality-assured according to Part 75.

Comment 105: Commenters 17705 and 17775 note the following reference inconsistencies:

- Section 63.10021 (a)(10) references compliance with paragraphs (a)(10)(i) through (iii), but subsection (iii) is missing. Commenters 17821 and 17881 also note this inconsistency.
- Section 63.10021 (a)(11) references compliance with paragraphs (a)(11)(i) through (iv), yet the rule text includes additional paragraphs (v) and (vi).
- Section 63.10021 (a)(12) references compliance with paragraphs (a)(12)(i) through (iii), but subsection (iii) is missing. Commenter 17881 also notes this inconsistency.
- Section 63.10021 (a)(13) references compliance with paragraphs (a)(13)(i) through (iii), but subsection (iii) is missing.
- Section 63.10021 (a)(14) references compliance with paragraphs (a)(14)(i) through (iii), but subsection (iii) is missing.

Response to Comment 105: The agency appreciates the comments, and the rule has been revised to remove these inconsistencies.

Comment 106: Several commenters (19536, 19537, 19538) state that although the default diluents language can be found in section 63.10005(k), Low Emitting EGUs, in the second numbered paragraph (1), this appears to be a location error. The commenter states that it is not obvious where this paragraph should be located. Commenter 17718 states that within the proposed regulatory language seen in 40 CFR 63.10005(k), the reference to performance test data requirements of “paragraph (l) of this section” does not seem appropriate. The reference to “paragraph (l)” seems to point to “63.10005(l)” which discusses default diluents gas concentrations to be used for calculating emissions during startup and shutdown events and does not seem pertinent to “performance testing” mentioned in proposed 63.10005(b). The commenter requests that the EPA clarify or provide guidance on how these two sections are to be used to aid qualification of LEE status.

Response to Comment 106: As mentioned earlier, these comments are moot, for the rule no longer requires emissions limitations during periods of startup or shutdown.

Comment 107: Commenter-17775 notes the following incorrect or missing references:

- Section 63.10005(k)(3) refers to section 63.10010(k)(3) however, there is no such provision. Commenter 17696 also notes this inconsistency.
- Section 63.10010(e) refers to procedures in (g)(1) through (g)(3) and (g)(6) however the EPA may have meant (e)(1) through (3) and (e)(6). Commenters 17714, 17795, 17718 and 17881 also note this inconsistency.
- Section 63.10010(h) refers to CPMS “as specified in Table 5.” Table 5 addresses “Performance Stack Testing Requirements.” Commenters 17752 and 17718 also note this incorrect reference. Commenter 17718 states that it appears that the EPA should have referenced Table 4 or Table 7 instead.
- The reference in section 63.10011(b) to paragraph (c)(6) should most likely be section 63.10011(b)(6). Commenter 17752 also notes this incorrect reference.
- The numbering of paragraph in section 63.10011(b) is not sequential. There is no section (b)(5) between (b)(4) and (b)(6). Commenter 17881 also notes this inconsistency.
- Section 63.10021(a)(8) refers to “maximum Hg input using Equation 9 of § 63.10011.” The

section and Equation 9 address non-Hg metals. Commenter 17752 also notes this incorrect reference.
- Table 4 states "If you demonstrate compliance using ... Fuel Analysis, you must "[m]aintain the fuel type or fuel mixture such that the applicable emission rate calculated according to §63.10011(d)(3), (4) and/or (5).

Response to Comment 107: The comments are moot, as described elsewhere the rule no longer requires operating parameter monitoring along with sorbent tube monitoring system monitoring, requires the use of Part 75 monitoring for those sources that also use monitors for the acid rain program, requires the establishment or monitoring of control device operating parameters, or requires fuel analysis of pollutants.

Comment 108: Commenter 17752 notes an incorrect reference in section 63.10031 (c).

Response to Comment 108: Although the comment lacks specificity, the agency has reviewed the section and revised the rule to correct references.

Comment 109: Commenter 17821 notes that appendix A, section 7.2.5.3.3 refers to paragraphs 7.1.2 through 7.1.19. Section 7.1 ends with paragraph 7.1.10.8. The EPA should modify this paragraph to correct the misidentified range of paragraph numbers.

Response to Comment 109: The reference to section 7.1.19 was a typographical error, which has been corrected in the final rule.

Comment 110: Commenters 17881 and 17718 note that paragraph (a)(4) of section 63.10010 references "systems described in paragraph 2.1 of this section," but there is no paragraph 2.1. The commenter suggests that it is likely that the EPA meant to reference section 2.1 in appendix A of proposed 40 CFR Part 63, subpart UUUUU instead.

Response to Comment 110: The reference in §63.10010(a)(4) to "paragraph 2.1 of this section" was clearly an error and has been removed from the rule.

Comment 111: Commenter 17881 notes that in paragraph 63.10021(a)(14)(ii), the reference should likely be "Appendix A of this part."

Response to Comment 111: The reference in §63.10021(a)(14)(ii) to "procedure 5 in Appendix F of 40 CFR Part 60" was incorrect and should have been "Appendix A to this subpart", as suggested by the commenter. However, note that in the final rule, all CEMS certification and QA requirements have been removed from §63.10021 and have been consolidated in §§63.10010 (b) through (h).

Comment 112: Commenter17821 recommends that the EPA revise the reference in section 63.10021(a)(16)(vi) to reflect the language in section 63.10006(r) which states that each performance tune-up must be no more than 18 months after the previous tune-up.

Response to Comment 112: The agency has revised the rule so that the performance tune-up testing frequency is consistent.

Comment 113: Commenter 18498 suggests that section 63.10021 (h)(ii) should be revised to reference appendix A or more specifically, section 5 to appendix A. The commenter states that for Hg CEMS, section 63.10021 (h)(ii) states the "Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 5 in Appendix F of 40 CFR Part 60." and contradicts section 63.10010(f) which references appendix A of this subpart.

Response to Comment 113: Section 63.10021 does not have a paragraph (h)(ii). The commenter is probably referring to §63.10021(a)(14)(ii), which references Procedure 5 in Appendix F of Part 60. See the response to Comment 113, above.

Comment 114: Commenter 17881 notes that the following references and sections are wrong:

- reference to section 63.10021(a)(10) in section 63.10031(g)(1)
- reference to section 63.10032(b) and (c) in section 63.10032(d)(5)

Response to Comment 114: The rule has been revised to correct the cross references.

Comment 115: Commenter 17718 states that that the reference in section 63.10021(a)(2) to section 63.10031(c) for keeping records of fuels should be section 63.10032(d) which outlines what fuel records are to be kept.

Response to Comment 115: The comment is moot, for the rule no longer requires fuel analysis of pollutants.

Comment 116: Commenter 17881 notes typographical errors in second sentence of section 63.10009(j)(2). The commenter recommends that the sentence be revised as follows:

> "If affected units and nonaffected units vent to the common stack, the nonaffected units must be shut down or vented to a different stack during the performance test or each affected and each nonaffected unit must meet the most stringent emissions limit"

Response to Comment 116: As mentioned elsewhere, the rule has been revised to clarify the language.

Comment 117: Commenter 17691 notes the following typographical errors in the rule:

- At 76 FR 25036, ECPMS could be modified [.. .], ECPMS should be ECMPS.
- At 63.9990, "(2) EGUs designed for coal< 8,300 Btu/lb. (b) Oil-fired EGUs are [...], 40 CFR 63 .9990(b) should begin on the next line for better understanding. 76 FR 25103
- At 63.10005, the numbering of the 63.10005(k) is out of sequence. The last paragraph, (1) Startup and Shut down default [.. .],should be numbered (4) instead of (1). 76 FR 25106
- At 63.10011, the numbering of the proposed 40 CFR 63 .1 0011 (b) is out of sequence. The numbering skips (5). 76 FR 25114

Response to Comment 117: The agency agrees with the commenter's first two suggestions, and the preamble and rule have been revised. No changes to the rule were made for the last two suggestions since the rule no longer requires default values for calculations during periods of startup or shutdown and since the rule no longer requires establishment of maximum pollutant fuel input levels.

Comment 118: Commenter 17691 states that the rule refers back to a site-specific monitoring plan required by section 63.10000(d) in several places, however, section 63.10000(d) says there is an exemption in which some sources will not need a site-specific monitoring plan (i.e., facilities with existing monitoring plans that meet the requirements of section 63.10010). Then, the proposed section 63.10010 refers back to 40 CFR 63.10000(d). The commenter states that this circular reference causes confusion, makes the regulation difficult to follow, and should be eliminated. The commenter suggests that for each instance where the text refers back to the proposed 40 CFR 63.10000(d), there should be additional language to address the exemption.

Response to Comment 118: Although the agency disagrees with the commenter's assertions, the rule has been revised so that only those EGUs without existing site-specific monitoring plans are required to submit those plans.

8E - Rule: Other Language Corrections

Commenter: 17851

Comment 1: Commenter 17851 states that it is impossible to eliminate the causes for certain malfunctions, such as lightning strikes. The commenter also recommends that the EPA allow notification by email or other electronic means in addition to faxing to make the rule more modern and useful. The commenter requests that the rule be modified to include these notification methods.

Response to Comment 1: The agency agrees that some causes for malfunctions may be difficult to eliminate, which is why the rule offers EGU owners or operators the ability to describe the circumstances concerning a malfunction in a report. The agency understands and appreciates the commenter's suggestion regarding use of electronic mail, but at this time the rule has not been changed to allow it for notification purposes. As the agency works through security and routing issues, the rule may be revised in the future to allow for electronic mail notification.

Comment 2: Commenter 17691 requests an inclusion of an equation in 40 CFR 63.10009 to provide a compliance demonstration method for each individual affected unit exhausting through a common stack.

Response to Comment 2: The EPA disagrees with the commenter's suggestion. As mentioned elsewhere, the rule contains instructions on how EGUs sharing a common stack and subject to an emissions averaging program meet eligibility requirements and demonstrate compliance. No changes have been made to the rule.

CHAPTER 9: GENERAL SUPPORT AND GENERAL OPPOSITION

9A - General Support

Comment 1: The EPA received 677,132 mass-mail and form letters expressing general support for the EGU NESHAP. Due to the high number of such comments for this proposed rule, these comments were categorized and sorted according to the group that organized the mass-mailing.

The U.S. Docket office identified 664,695 mass-mail comment letters and assigned them to 65 DCNs. These mass-mail DCNs are listed in Table 9A-1 of this section with the count of comment letters and the associated organization.

More mass-mail comment letters were identified from the remaining comment letters and are listed in Tables 9A-2 through 9A-20 in this section.

Three thousand and fifty (3,050) letters expressing general support that are not associated with any mass-mail campaign are listed in Table 9A-21 in this section.

Many organizations provided members with form letters. Form letters containing substantive comments had a few representative letters excerpted and summarized for the Response to Comments document, and the remaining letters are listed here.

Many commenters representing the American Lung Association (18576, 18590, 18707, 18716, 18721, 18749, 18750, 18751, 18823, 18897, 18898, 18899, 18900, 18901 and 18930) wrote in support of the proposed mercury and air toxics standards, particularly in regard to the standards' effect on human health. Further comments from the American Lung Association can be found in the document in comments from commenters 16826 and 18445.

Commenters (19111, 19210, 19225) representing chapters of the National Audubon Society, wrote to support the proposed rule and its reduction of mercury impacts on wildlife. Other Audubon Society commenters in this document are 17278, 17279, 17405 and 19101.

Commenters (16844, 17278, 17279, 17291, 17294, 17625, 18248, 18431, 18666, 19225) also expressed general support for the proposed rule, citing benefits to human health and the environment, particularly due to controls on Hg emissions. Commenters 17291, 17294 and 19225 encourage the EPA to make the standard more stringent.

Comment 2: Commenter 18025 owns and operates four coal units and is part owner of four additional units ranging in size from small to large, anticipates the units will achieve the proposed standards, and therefore supports the proposed subcategories and emissions standards for coal-fired EGUs and agrees that they are consistent with requirements in the CAA.

Response to Comments 1 - 2: The EPA appreciates the commenters' support for the Mercury and Air Toxics Standards.

Section 9A Tables

Mass Mailings - General Support for the Proposed Rule

Table 9A-1. Mass mail comments identified by the U.S. Docket Office

DCN	Docket Entry	Count
3084	Early Mass Comment Campaign sponsored by National Wildlife Federation (NWF)	10,845
3085	Early Mass Comment Campaign sponsored by Environmental Defense Fund (EDF)	66,532
3086	Early Mass Comment Campaign sponsored by League Of Conservation Voters	65,149
3087	Early Mass Comment Campaign sponsored by Sierra Club	27,019
3088	Early Mass Comment Campaign sponsored by Union of Concerned Scientists	10,872
3089	Early Mass Comment Campaign sponsored by American Lung Association Action Network	2,116
3090	Early Mass Comment Campaign sponsoring organization unknown	3,053
3091	Early Mass Comment Campaign sponsored by Union of Concerned Scientists	47
6638	Mass Comment Campaign sponsored by Greenpeace	4,685
11053	Mass Comment Campaign sponsored by Earthjustice	8,704
12055	Mass Comment Campaign sponsored by Earthjustice (Part 1 of 2)	3,112
12056	Mass Comment Campaign sponsored by Earthjustice (Part 2 of 2)	
13059	Mass Comment Campaign sponsored by the League of Conservation Voters	593
13060	Mass Comment Campaign sponsoring organization unknown	78
13061	Mass Comment Campaign sponsored by Citizens for Pennsylvania's Future (PennFuture)	172
13062	Mass Comment Campaign sponsoring organization unknown	202
13063	Mass Comment Campaign sponsored by Sierra Club	27,255
13421	Mass Comment Campaign sponsoring organization unknown	4,258
16530	Mass Comment Campaign sponsoring organization unknown	95
16531	Mass Comment Campaign sponsored by Environment Florida	43
16546	Mass Comment Campaign sponsored by Earthjustice	29
16547	Mass Comment Campaign sponsoring organization unknown	220
16553	Mass Comment Campaign sponsored by Natural Resources Defense Council (NRDC)	9,678
16554	Mass Comment Campaign sponsoring organization unknown	513
16562	Mass Comment Campaign sponsoring organization unknown	73
16565	Mass Comment Campaign sponsored by Physicians for Social Responsibility	2,607
16566	Mass Comment Campaign sponsoring organization unknown	42
16567	Mass Comment Campaign sponsored by National Audubon Society	5,279
17007	Mass Mail Campaign sponsored by Alliance for Climate Protection	47,525
17030	Mass Mail campaign sponsored by First Congregational Church of Sonoma	28
17058	Mass Comment campaign sponsored by Environmental Defense Fund (EDF)	18,425

17059	Mass Comment campaign sponsored by Natural Resources Council of Maine	123
17060	Mass Comment campaign sponsored by National Wildlife Federation Action Fund	9,106
17802	Mass comment Campaign sponsored by Kentucky Environmental Foundation	12
18190	Mass comment campaign sponsored by Sierra Club	9,440
18490	Mass Comment Campaign sponsored by Ohio Citizen Action	1,405
18491	Mass Comment Campaign sponsored by Fair Climate Project	52
18492	Mass Comment Campaign sponsored by Clean Air Council	49
18493	Mass Comment Campaign sponsoring organization unknown	39
18494	Mass Comment Campaign sponsored by Interfaith Power & Light	643
18495	Mass Comment Campaign sponsoring organization unknown	2,181
18496	Mass Comment Campaign sponsored by Restoring Eden	11,819
18546	Mass Comment Campaign sponsored by National Wildlife Federation (NWF)	433
18638	Mass Comment Campaign sponsoring organization unknown	58
18639	Mass Comment Campaign sponsored by Citizens Campaign for the Environment	33,165
18640	Mass Comment Campaign sponsoring organization unknown	67
18641	Mass Comment Campaign sponsoring organization unknown	29
18642	Mass Comment Campaign sponsoring organization unknown	105
18643	Mass Comment Campaign sponsoring organization unknown	2,611
18965	Mass Comment Campaign sponsored by CREDO Action	136,779
18979	Mass Comment Campaign sponsored by GASP (formerly Alabama First)	94
18986	Mass Comment Campaign sponsored by NC Conservation Network	904
18988	Mass Comment Campaign sponsored by One Million Calls For Clean Energy	4,481
19112	Mass Comment Campaign sponsored by Greenpeace	77,844
19113	Mass Comment Campaign sponsoring organization unknown	20
19125	Mass Comment Campaign sponsored by Respiratory Health Association of Metropolitan Chicago	94
19150	Mass comment campaign sponsored by Earthjustice	37,286
19550	Mass Comment Campaign sponsored by Fall-line Alliance for a Clean Environment (FACE)	130
19573	Mass Comment Campaign sponsoring organization unknown	23
19615	Mass Comment Campaign sponsored by GreenFaith, Interfaith Partners in Action for the Earth	13,074
19632	Mass Comment Campaign sponsoring organization unknown	25
19643	Mass Comment Campaign sponsored by Moms Clean Air Force	95
19644	Mass Comment Campaign sponsoring organization unknown	2,959
19647	Mass Comment Campaign sponsoring organization unknown	32
19648	Mass Comment Campaign sponsored by Environmental Defense Fund (EDF)	269
	Total:	664,695

In addition to the mass mailings identified by the Docket Office, 12,437 mass mail comments were also identified by RTI International. Not all of the comments can be linked to a specific organization.

Table 9A-2. American Lung Association

3328	5122	5212	5216	7582	7583	7586	7587	7588	7658	7659	7662
7663	7664	7665	7666	7667	7668	7669	7670	7671	7673	7674	7675
7747	7828	7859	8287	8434	8520	8521	8579	8958	8961	9022	9072
9112	9154	9159	9172	9376	9790	11314	11915	12384	12409	12411	12418
12425	12430	12431	12439	12467	12508	12521	12589	12630	12639	12675	12676
12715	12716	12720	12768	12801	13099	13539	14288	14303	14345	14347	14844
14901	14952	14965	14969	14972	14973	15020	15171	15209	15230	15280	15387
15457	15525	16054	16073	16214	16215	16217	16228	16241	17075	17076	17080
17081	17082	17086	17146	17147	18531	18559	18663	18676	18678	18679	18680
18688	18698	18914	18945	19203	19250						
										Total:	114

Table 9A-3. National Audubon Society

14180	14186	14191	14227	14228	14230	14233	14235	14239	14243	14258	14259
14265	14266	14269	14270	14273	14276	14277	14278	14285	14289	14290	14291
14292	14293	14294	14295	14296	14297	14298	14302	14304	14305	14306	14307
14308	14320	14321	14322	14323	14324	14326	14351	14352	14353	14355	14356
14357	14360	14361	14362	14363	14364	14383	14384	14385	14387	14389	14396
14401	14412	14415	14438	14439	14452	14453	14454	14455	14456	14457	14458
14459	14727	14767	14768	14778	14779	14791	14793	14805	14841	14843	14846
14853	14902	14903	14950	14951	14953	14962	14963	14964	14966	14970	14974
14975	15003	15006	15016	15017	15019	15042	15044	15050	15060	15165	15166
15167	15168	15194	15195	15196	15198	15211	15244	15252	15264	15265	15267
15268	15275	15277	15278	15279	15289	15290	15291	15292	15293	15294	15295
15296	15297	15298	15299	15324	15325	15326	15327	15333	15334	15340	15342
15343	15346	15386	15346	15389	15390	15391	15399	15400	15401	15405	15406
15407	15409	15419	15420	15421	15422	15423	15461	15494	15498	15532	15681
15683	15684	15891	15895	15913	16011	16049	16060	16064	16065	16066	16067
16068	16069	16072	16080	16081	16083	16084	16092	16100	16104	16117	16218
16282	16312	16528	16587								
										Total:	196

Table 9A-4. Care2Address

13791	13863	13864	13867	13869	13873	13874	13876	13880	13881	13882	13883
13888	13923	13983	17987	17988	17989	17990	17991	17992	17993	17994	17995
17996	17997	17998	18000	18001	18002	18003	18004	18005	18006	18007	18008
18010	18011	18012	18013	18050	18064	18069	18070	18071	18072	18073	18074
18075	18076	18077	18078	18079	18080	18081	18082	18083	18084	18085	18086

18087	18088	18089	18090	18091	18092	18093	18094	18095	18096	18097	18098
18099	18100	18101	18102	18103	18105	18106	18107	18108	18109	18110	18113
18114	18115	18117	18118	18120	18121	18122	18124	18126	18127	18128	18129
18130	18131	18132	18133	18135	18136	18138	18140	18141	18142	18143	18144
18145	18146	18148	18149	18150	18151	18152	18154	18155	18156	18159	18161
18162	18163	18164	18165	18166	18167	18168	18169	18170	18171	18173	18175
18178	18179	18180	18181	18182	18183	18184	18187	18339	18340	18342	18343
18344	18345	18347	18345	18349	18350	18464	18466	18469	18470	18471	18473
18474	18578	18579	18587	18588	18589	18591	18592	18593	18594	18595	18596
18598	18629	18648	18651	18652	18656	18685	18691	18715	18717	18722	18723
18724	18725	18726	18727	18728	18766	18767	18781	18797	18798	18799	18800
18801	18802	18824	18825	18826	18827	18836	18851	18880	18881	18882	18883
18884	18976	18977	18978	18980	18982	18983	18984	18985	18989	18990	18992
18993	18994	18995	18996	18997	18998	18999	19000	19001	19002	19003	19031
19043	19044	19045	19046	19047	19048	19049	19050	19051	19052	19054	19055
19056	19058	19059	19060	19061	19062	19063	19064	19065	19066	19067	19068
19069	19070	19071	19072	19073	19074	19086	19087	19088	19092	19093	19106
19108	19110	19115	19116	19132	19133	19134	19136	19138	19139	19180	19181
19182	19183	19184	19186	19187	19190	19191	19306	19307	19333	19334	19335
19336	19337	19338	19339	19340	19341	19342	19343	19344	19345	19346	19347
19348	19349	19350	19351	19352	19353	19354	19355	19356	19357	19358	19359
19360	19361	19362	19363	19364	19365	19366	19367	19368	19369	19370	19371
19372	19373	19374	19375	19376	19377	19378	19379	19380	19381	19382	19383
19384	19385	19386	19387	19388	19389	19390	19391	19392	19393	19394	19395
19396	19397	19398	19399	19400	19401	19402	19403	19404	19405	19406	19407
19408	19409	19410	19411	19412	19413	19414	19415	19416	19417	19418	19419
19420	19421	19422	19423	19424	19425	19426	19427	19428	19429	19430	19431
19438	19439	19440	19441	19442	19443	19444	19445	19446	19447	19448	19449
19450	19451	19452	19453	19454	19455	19456	19457	19458	19459	19460	19462
19464	19465	19466	19467	19468	19470	19471	19472	19473	19474	19475	19476
19477	19478	19479	19480	19481	19482	19487	19492	19495	19499	19500	19501
19502	19503	19504	19505	19544	19567	19568	19569	19593	19608		
										Total:	443

Table 9A-5. Change.org

3640	3656	3657	3665	3666	3686	3687	3688	3698	3700	3703	3735
3736	3737	3738	3739	3793	3794	3795	3823	3907	3941	3942	3943
4001	4002	4003	4004	4005	4006	4007	4008	4009	4010	4011	4012
4014	4015	4016	4017	4018	4019	4020	4021	4022	4023	4024	4025
4026	4247	4250	4251	4253	4254	4255	4256	4257	4258	4259	4260
4261	4262	4263	4282	4284	4285	4287	4288	4289	4290	4303	4304
4305	4307	4308	4309	4310	4311	4312	4314	4315	4320	4347	4348
4349	4350	4351	4392	4393	4394	4395	4429	4430	4431	4454	4783

4825	4999	5000	5014	5042	5053	5054	5065	5082	5097	5138	5182
5183	5190	5191	5203	5204	5264	5280	5348	5349	5350	5351	5352
5353	5354	5355	5356	5369	5413	5414	5415	5416	5691	5701	5702
5703	5704	5705	5706	5707	5708	5709	5710	5711	5712	5713	5750
5751	5752	5753	5752	5852	5854	5856	5857	6113	6114	6494	6495
6496	6497	6500	6508	6509	6514	6517	6518	6519	6523	6524	6525
6526	6527	6530	6531	6532	6533	14776					
										Total:	175

Table 9A-6. EarthJustice

12116	12117	12118	12119	12120	12121	12122	12134	12135	12136	12137	12138
12139	12140	12141	12143	12144	12157	12158	12159	12160	12161	12162	12163
12164	12165	12166	12167	12168	12169	12179	12180	12181	12182	12183	12188
12189	12194	12196	12197	12198	12199	12200	12212	12213	12214	12215	12217
12218	12219	12220	12291	12292	12293	12294	12300	12302	12303	12304	12305
12315	12318	12319	12320	12321	12322	12323	12324	12325	12326	12327	12328
12329	12330	12331	12333	12338	12340	12343	12346	12347	12348	12349	12350
12351	12352	12353	12354	12357	12358	12360	12361	12362	12363	12364	12365
12366	12367	12368	12370	12371	12372	12373	12679	13700	13712	13733	13767
13768	13769	13770	13771	13772	13773	13774	13775	13777	13778	13779	13780
13781	13782	13783	13784	13786	13787	13788	13789	13790	13792	13810	13811
13812	13813	13814	13815	13816	13861	13862	13865	13866	13870	13875	13878
13961	14034	14424	14034	14507	14508	14515	14516	14517	14518	14600	14601
14602	14603	14604	14605	14606	14607	14608	14609	14611	14615	14622	14623
14626	14627	14632	14633	14650	14653	14655	14663	14670	14676	14677	15792
15828	15867	15873	15875	15915	15917	15918	15919	15921	15922	15923	15933
15954	15960	15985	15999	16000	16383	16413	17327	17328	17491	17981	17999
18104	18111	18112	18125	18139	18147	18172	18177	18189	18250	18251	18252
18253	18255	18256	18257	18258	18264	18271	18273	18275	18351	18352	18355
18358	18359	18461	18462	18586	18597	18650	18653	18657	18658	18713	18718
18789	18834	18842	18847	19104	19105	19107	19137	19305			
										Total:	249

Table 9A-7. Environmental Defense Fund (EDF)

3092	3093	3094	3095	3096	3097	3098	3099	3100	3101	3102	3103
3104	3105	3138	3139	3140	3141	3142	3143	3144	3145	3146	3147
3148	3149	3150	3151	3152	3153	3154	3155	3156	3157	3158	3159
3160	3188	3223	3224	3246	3247	3248	3249	3250	3251	3252	3253
3254	3255	3256	3258	3259	3260	3261	3262	3263	3264	3265	3266
3267	3268	3269	3270	3275	3276	3277	3278	3279	3280	3281	3282
3283	3284	3285	3286	3287	3288	3289	3290	3291	3292	3293	3294
3295	3296	3297	3298	3299	3300	3301	3302	3303	3304	3305	3306

3307	3308	3309	3315	3316	3317	3318	3319	3320	3321	3322	3323
3324	3325	3326	3327	3329	3330	3331	3334	3335	3336	3358	3361
3364	3366	3367	3371	3372	3373	3375	3378	3379	3380	3381	3383
3384	3389	3390	3392	3397	3398	3399	3400	3401	3402	3403	3404
3405	3406	3407	3406	3409	3410	3411	3412	3413	3414	3415	3416
3417	3418	3419	3420	3436	3437	3438	3439	3440	3441	3442	3443
3444	3454	3455	3456	3457	3458	3459	3460	3461	3494	3495	3496
3497	3498	3499	3500	3501	3502	3503	3504	3505	3506	3510	3512
3513	3515	3516	3517	3518	3519	3549	3550	3551	3552	3553	3554
3555	3556	3557	3558	3567	3569	3570	3571	3572	3573	3574	3575
3576	3577	3578	3579	3580	3581	3582	3583	3584	3585	3586	3587
3592	3593	3594	3595	3596	3597	3598	3599	3600	3601	3602	3603
3604	3605	3606	3607	3608	3609	3610	3611	3612	3613	3614	3615
3616	3617	3618	3619	3620	3621	3622	3623	3624	3625	3626	3627
3628	3629	3630	3631	3632	3633	3634	3635	3636	3637	3638	3639
3641	3642	3643	3644	3645	3646	3647	3648	3649	3650	3651	3652
3653	3654	3655	3658	3659	3660	3661	3662	3663	3664	3667	3668
3669	3670	3671	3672	3673	3674	3675	3676	3677	3678	3679	3680
3681	3682	3683	3684	3685	3689	3692	3693	3694	3695	3696	3697
3699	3701	3702	3704	3706	3707	3708	3709	3710	3711	3712	3713
3714	3715	3716	3717	3718	3719	3720	3721	3722	3723	3724	3725
3726	3727	3728	3729	3730	3731	3732	3733	3734	3741	3742	3743
3744	3745	3746	3747	3756	3757	3758	3759	3760	3761	3762	3763
3764	3765	3766	3767	3768	3769	3773	3774	3775	3776	3777	3778
3779	3780	3781	3782	3783	3784	3785	3786	3787	3788	3789	3790
3791	3792	3805	3806	3807	3808	3809	3810	3811	3812	3813	3814
3817	3818	3819	3820	3821	3822	3827	3828	3829	3830	3833	3834
3835	3836	3838	3839	3840	3841	3842	3843	3847	3848	3849	3853
3854	3855	3856	3861	3862	3863	3864	3869	3870	3871	3875	3876
3877	3878	3879	3884	3885	3886	3890	3895	3900	3908	3921	3922
3923	3924	3925	3938	3939	3944	3945	3946	3947	3949	3950	3951
3952	3953	3954	3955	3956	3957	3958	3959	3960	3961	3962	3963
3964	3965	3966	3967	3968	3969	3970	3971	3972	3973	3974	3975
3976	3977	3978	3979	3980	3981	3982	3983	3984	3985	3986	3987
3988	3989	3990	3991	3992	3993	3994	3995	3996	3997	3998	3999
4000	4013	4027	4028	4029	4030	4032	4033	4034	4035	4036	4037
4038	4039	4040	4041	4042	4043	4044	4045	4046	4047	4049	4074
4075	4076	4099	4100	4101	4102	4103	4104	4105	4106	4107	4108
4109	4110	4111	4112	4113	4114	4115	4116	4117	4118	4119	4120
4121	4122	4123	4124	4125	4126	4127	4128	4129	4137	4138	4140
4141	4142	4143	4144	4145	4146	4147	4148	4162	4167	4168	4169
4170	4171	4172	4171	4174	4175	4176	4177	4178	4179	4180	4181
4182	4183	4184	4185	4186	4187	4188	4189	4190	4191	4192	4193
4194	4196	4200	4216	4217	4218	4219	4220	4221	4222	4223	4224

4225	4226	4227	4228	4229	4230	4231	4232	4233	4234	4235	4236
4238	4241	4242	4243	4244	4245	4246	4248	4249	4252	4264	4265
4266	4268	4274	4275	4276	4277	4278	4279	4280	4281	4283	4286
4291	4292	4293	4295	4296	4298	4299	4300	4301	4302	4306	4313
4316	4317	4318	4319	4321	4322	4323	4324	4325	4326	4327	4328
4329	4330	4331	4332	4333	4334	4335	4336	4337	4338	4339	4340
4345	4346	4352	4353	4354	4355	4356	4357	4358	4359	4360	4361
4362	4377	4378	4379	4380	4381	4382	4383	4384	4385	4386	4387
4388	4389	4390	4391	4396	4397	4398	4399	4400	4402	4403	4404
4405	4406	4407	4408	4409	4410	4412	4413	4414	4415	4416	4417
4418	4419	4420	4421	4422	4423	4424	4425	4426	4427	4428	4433
4435	4436	4437	4438	4442	4443	4444	4445	4446	4447	4450	4451
4452	4453	4455	4456	4457	4458	4459	4460	4461	4463	4464	4465
4466	4467	4468	4469	4470	4471	4472	4473	4474	4475	4476	4477
4478	4479	4480	4481	4482	4484	4485	4486	4489	4490	4491	4492
4493	4497	4498	4499	4500	4501	4503	4504	4505	4506	4507	4508
4509	4510	4511	4512	4513	4514	4515	4516	4517	4518	4519	4520
4521	4527	4528	4529	4530	4531	4532	4533	4534	4537	4538	4539
4540	4542	4543	4546	4547	4548	4549	4550	4551	4552	4553	4555
4556	4558	4559	4560	4561	4562	4564	4566	4567	4568	4569	4570
4572	4573	4574	4575	4576	4577	4578	4579	4581	4582	4583	4584
4585	4586	4587	4588	4589	4590	4591	4592	4593	4594	4595	4596
4597	4598	4599	4602	4603	4604	4605	4606	4608	4609	4610	4611
4612	4613	4614	4616	4617	4619	4620	4621	4622	4623	4624	4625
4626	4628	4629	4630	4631	4632	4633	4634	4635	4636	4637	4638
4639	4640	4641	4643	4646	4647	4648	4649	4650	4651	4652	4653
4655	4656	4657	4658	4659	4660	4661	4663	4664	4669	4670	4675
4676	4679	4680	4681	4682	4683	4691	4692	4693	4694	4695	4696
4698	4699	4700	4701	4702	4703	4704	4707	4708	4709	4710	4711
4712	4713	4714	4715	4716	4717	4719	4720	4722	4723	4724	4725
4726	4727	4728	4729	4731	4733	4734	4735	4736	4737	4738	4739
4740	4741	4742	4743	4744	4745	4746	4747	4748	4749	4750	4752
4753	4754	4755	4756	4757	4758	4759	4760	4761	4762	4763	4764
4765	4766	4767	4768	4769	4784	4785	4786	4787	4788	4789	4795
4796	4798	4804	4798	4809	4810	4811	4812	4818	4819	4820	4821
4822	4823	4824	4920	4922	4924	4926	4927	4928	4931	4933	4942
4982	4983	4993	5005	5006	5007	5026	5027	5028	5029	5030	5031
5085	5098	5142	5158	5159	5174	5175	5192	5193	5205	5206	5207
5245	5247	5267	5268	5269	5295	5305	5318	5321	5330	5331	5345
5346	5446	5447	5448	5449	5450	5452	5453	5454	5455	5456	5457
5458	5459	5460	5517	5518	5560	5562	6112	6115	6116	6117	6118
6119	6120	6121	6122	6123	6124	6125	6126	6127	6128	6129	6130
6131	6132	6133	6134	6135	6136	6137	6139	6140	6141	6142	6143
6144	6145	6146	6147	6148	6149	6150	6151	6152	6153	6154	6155

6156	6157	6158	6159	6160	6161	6162	6163	6164	6165	6166	6167
6168	6169	6170	6171	6172	6173	6174	6175	6176	6178	6179	6180
6181	6182	6183	6184	6185	6186	6187	6188	6189	6190	6191	6192
6193	6194	6195	6196	6197	6198	6199	6200	6201	6202	6203	6204
6205	6206	6207	6208	6209	6210	6211	6212	6213	6214	6215	6216
6217	6218	6219	6220	6221	6222	6223	6224	6225	6226	6227	6228
6229	6230	6231	6232	6233	6234	6235	6236	6237	6238	6239	6240
6241	6242	6243	6244	6245	6246	6247	6248	6249	6250	6251	6252
6253	6254	6255	6256	6257	6258	6259	6260	6261	6262	6263	6264
6265	6266	6267	6268	6269	6270	6271	6272	6273	6274	6275	6276
6277	6278	6279	6280	6281	6282	6283	6284	6285	6286	6287	6288
6289	6290	6291	6292	6293	6294	6295	6296	6297	6298	6299	6300
6301	6302	6303	6304	6305	6306	6307	6308	6309	6310	6311	6312
6313	6314	6315	6316	6317	6318	6319	6320	6321	6322	6323	6324
6325	6326	6327	6328	6329	6330	6331	6332	6333	6334	6335	6336
6337	6338	6339	6340	6341	6342	6343	6344	6345	6346	6347	6348
6349	6350	6351	6352	6353	6354	6355	6356	6357	6358	6359	6360
6361	6362	6363	6364	6365	6366	6367	6368	6369	6370	6371	6372
6373	6374	6375	6376	6377	6378	6379	6380	6381	6382	6383	6384
6385	6386	6387	6388	6389	6390	6391	6392	6393	6394	6395	6396
6397	6398	6399	6400	6401	6402	6403	6404	6405	6406	6407	6408
6409	6410	6411	6412	6413	6414	6415	6416	6417	6418	6419	6420
6421	6422	6423	6424	6425	6426	6427	6428	6429	6430	6431	6432
6433	6434	6435	6436	6437	6438	6439	6440	6441	6442	6443	6444
6445	6446	6447	6448	6449	6450	6451	6452	6453	6454	6455	6456
6457	6458	6459	6460	6461	6462	6463	6464	6465	6466	6467	6468
6469	6470	6471	6472	6473	6474	6475	6476	6477	6478	6479	6480
6481	6482	6483	6482	6485	6486	6487	6488	6489	6490	6491	6492
6493	6498	6499	6501	6502	6503	6504	6505	6506	6507	6510	6511
6512	6513	6515	6516	6520	6521	6522	6528	6529	6534	6535	6536
6537	6538	6539	6540	6541	6542	6544	6545	6546	6547	6548	6549
6550	6551	6552	6553	6554	6555	6556	6557	6558	6559	6560	6561
6562	6563	6564	6565	6566	6567	6568	6569	6570	6571	6572	6573
6574	6575	6576	6577	6578	6579	6580	6581	6582	6583	6585	6586
6587	6588	6589	6590	6591	6592	6593	6594	6595	6596	6597	6598
6599	6600	6601	6602	6603	6604	6605	6606	6607	6608	6609	6610
6611	6612	6613	6614	6615	6616	6617	6618	6619	6620	6621	6622
6623	6624	6625	6626	6627	6628	6629	6630	6631	6632	6633	6634
6636	6664	6665	6666	6667	6668	6669	6670	6671	6672	6673	6674
6675	6676	6677	6678	6679	6680	6681	6682	6683	6684	6685	6686
6687	6688	6689	6690	6691	6692	6693	6695	6696	6697	6698	6699
6700	6701	6702	6703	6704	6705	6706	6707	6708	6709	6710	6711
6712	6713	6714	6715	6716	6717	6718	6719	6720	6721	6722	6723
6724	6725	6726	6727	6728	6729	6730	6731	6732	6733	6734	6735

6736	6737	6738	6739	6740	6741	6742	6743	6744	6745	6746	6747
6748	6749	6750	6751	6752	6753	6754	6755	6756	6757	6758	6759
6760	6761	6762	6763	6764	6765	6766	6767	6768	6769	6770	6771
6772	6773	6774	6775	6776	6777	6778	6779	6780	6781	6782	6783
6784	6785	6786	6787	6788	6789	6790	6791	6792	6793	6794	6795
6796	6797	6798	6799	6800	6801	6802	6803	6804	6805	6806	6807
6808	6809	6810	6811	6812	6813	6814	6815	6816	6817	6818	6819
6820	6821	6822	6823	6824	6825	6826	6827	6828	6829	6830	6831
6832	6833	6834	6835	6836	6837	6838	6839	6840	6841	6842	6843
6844	6845	6846	6847	6848	6849	6850	6851	6852	6853	6854	6855
6856	6857	6858	6859	6860	6861	6862	6863	6864	6865	6866	6867
6868	6869	6870	6871	6872	6873	6874	6875	6876	6877	6878	6879
6880	6881	6882	6883	6884	6885	6886	6887	6888	6889	6890	6891
6892	6893	6894	6895	6896	6897	6898	6899	6900	6901	6902	6903
6904	6905	6906	6907	6908	6909	6910	6911	6912	6913	6914	6915
6916	6917	6918	6919	6920	6921	6922	6923	6924	6925	6926	6927
6928	6929	6930	6931	6932	6933	6934	6935	6936	6937	6938	6939
6940	6941	6942	6943	6944	6945	6946	6947	6948	6949	6950	6951
6952	6953	6954	6955	6956	6957	6958	6959	6960	6961	6962	6963
6964	6965	6966	6967	6968	6969	6970	6971	6972	6973	6974	6975
6976	6977	6978	6977	6980	6981	6982	6983	6984	6985	6986	6987
6988	6989	6990	6991	6992	6993	6994	6995	6996	6997	6998	6999
7000	7001	7002	7003	7004	7005	7006	7007	7008	7009	7010	7011
7012	7013	7014	7015	7016	7017	7018	7019	7020	7021	7022	7023
7024	7025	7026	7027	7028	7029	7030	7031	7032	7033	7034	7035
7036	7037	7038	7039	7040	7041	7042	7043	7044	7045	7046	7047
7048	7049	7050	7051	7052	7053	7054	7055	7056	7057	7058	7059
7060	7061	7062	7077	7078	7079	7080	7081	7082	7083	7084	7085
7086	7087	7088	7198	7199	7200	7201	7202	7203	7204	7205	7206
7207	7208	7209	7210	7211	7212	7213	7214	7215	7216	7217	7218
7219	7220	7221	7222	7223	7224	7225	7226	7227	7228	7229	7230
7231	7232	7233	7234	7235	7236	7237	7238	7239	7240	7241	7242
7243	7244	7254	7255	7256	7302	7303	7304	7305	7346	7347	7348
7349	7350	7351	7352	7353	7354	7355	7356	7357	7358	7496	7499
7500	7501	7502	7503	7504	7505	7506	7507	7508	7509	7510	7511
7512	7513	7514	7515	7516	7517	7518	7519	7520	7521	7522	7523
7524	7525	7526	7527	7528	7529	7530	7531	7532	7533	7534	7538
7539	8256	8257	8300	8301	8580	8581	8582	8583	8584	8585	8586
8587	8588	8877	8878	8879	9268	9269	9270	9271	9272	9273	9274
9275	9276	9518	9519	9520	9521	9522	9524	9525	9526	9527	9528
9529	9530	9531	9532	9533	9534	9535	9536	9537	9538	9539	9540
9542	9543	9544	9545	9546	9547	9548	9550	9551	9552	9553	9554
9555	9556	9557	9558	9559	9560	9561	9562	9563	9564	9565	9566
9567	9568	9570	9571	9572	9573	9574	9576	9577	9578	9579	9580

9581	9582	9583	9584	9585	9586	9587	9588	9589	9590	9591	9592
9593	9594	9595	9596	9597	9598	9599	9600	9601	9602	9603	9604
9605	9606	9607	9608	9609	9610	9611	9612	9613	9614	9617	9618
9619	9620	9621	9622	9623	9624	9625	9626	9627	9628	9629	9630
9631	9632	9633	9634	9635	9636	9637	9638	9639	9640	9641	9642
9643	9644	9645	9646	9647	9648	9650	9651	9652	9653	9654	9655
9656	9657	9658	9659	9660	9661	9662	9663	9664	9666	9667	9668
9669	9670	9671	9672	9673	9674	9675	9676	9677	9678	9679	9680
9681	9682	9683	9684	9685	9686	9687	9688	9689	9690	9691	9692
9693	9694	9695	9696	9697	9698	9699	9701	9702	9703	9704	9705
9706	9707	9708	9709	9711	9712	9713	9714	9716	9718	9719	9720
9721	9722	9723	9724	9725	9726	9727	9765	9766	9767	9768	9769
9770	9860	9963	9964	9965	9966	9967	9968	9969	9970	9971	9972
9973	9974	9975	9974	9978	9979	9980	9981	9982	9983	9984	9985
9986	9987	9988	9989	9990	9991	9992	9993	9994	9995	9996	9997
9998	9999	10000	10002	10003	10004	10005	10006	10007	10008	10009	10011
10012	10013	10014	10015	10016	10017	10018	10019	10020	10021	10022	10023
10024	10025	10026	10027	10029	11064	11065	11066	11067	11108	11109	11110
11111	11112	11113	11114	11115	11116	11117	11118	11119	11120	11121	11122
11123	11124	11125	11126	11127	11128	11129	11130	11131	11132	11133	11134
11135	11136	11137	11139	11140	11141	11142	11143	11144	11145	11146	11147
11148	11149	11150	11151	11152	11153	11154	11155	11156	11157	11158	11159
11160	11161	11162	11163	11164	11165	11166	11167	11168	11169	11170	11171
11172	11173	11174	11175	11176	11177	11178	11179	11180	11181	11182	11183
11184	11185	11186	11187	11188	11189	11190	11191	11192	11193	11194	11195
11196	11197	11198	11199	11200	11201	11202	11203	11204	11205	11206	11207
11208	11209	11210	11211	11212	11213	11214	11215	11216	11217	11218	11219
11220	11221	11222	11223	11224	11225	11226	11227	11228	11229	11230	11231
11232	11233	11234	11235	11236	11237	11238	11239	11240	11241	11242	11243
11244	11245	11246	11247	11248	11249	11250	11251	11252	11253	11254	11255
11256	11257	11258	11259	11260	11261	11262	11263	11264	11265	11266	11267
11268	11269	11270	11271	11272	11273	11274	11275	11276	11277	11278	11279
11280	11281	11285	11286	11287	11288	11298	11351	11352	11403	11404	11439
11440	11441	11442	11443	11444	11446	11447	11448	11711	11712	11757	11772
11784	11785	11793	11794	11795	11810	11811	11812	11813	11814	11815	11816
12077	12078	12079	12080	12101	12102	12103	12105	12106	12107	12108	12110
12112	12113	12114	12115	12173	12174	12175	12176	12177	12185	12190	12191
12195	12203	12204	12205	12206	12207	12208	12209	12210	12211	12225	12234
12235	12236	12237	12241	12268	12269	12270	12271	12272	12273	12274	12275
12276	12277	12285	12286	12306	12309	12310	12311	12313	12317	12337	12342
12359	13696	13699	13701	13707	13709	13716	13801	13868	13871	13877	13879
14187	14422	14423	14425	14648	14657	15444	15668	15669	15671	15672	15673
15674	15675	15677	15774	15775	15776	15777	15778	15784	15787	15788	15789
15791	15852	15865	15866	15876	15930	15951	15952	15953	15955	15984	16377

16378	16382	16386	16387	16388	16389	16390	16391	16392	16393	16394	16395
16396	16397	16398	16399	16400	16401	16418	16448	16452	16453	16454	16455
16456	16457	16458	16459	16460	16462	16463	16464	16465	16466	16467	16468
16476	16477	16478	16480	16481	16482	16483	16484	16485	16486	16500	16978
16979	16980	16981	16982	17047	17048	17050	17051	17229	17230	17232	17235
17236	17252	17253	17256	17272	17288	17301	17302	17311	17312	17313	17326
17392	17394	17410	17394	17412	17413	17414	17415	17416	17417	17418	17419
17420	17421	17422	17423	17424	17425	17426	17427	17428	17429	17430	17431
17432	17433	17434	17435	17436	17437	17438	17439	17440	17441	17442	17443
17444	17446	17447	17448	17449	17450	17451	17452	17453	17454	17455	17456
17458	17459	17460	17461	17462	17464	17467	17468	17469	17474	17475	17476
17477	17478	17479	17480	17481	17482	17483	17484	17485	17487	17488	17492
17493	17494	17495	17497	17498	17499	17500	17501	17502	17503	17504	17505
17506	17507	17508	17509	17510	17511	17512	17513	17514	17515	17516	17517
17518	17519	17520	17521	17522	17523	17524	17525	17526	17527	17528	17529
17530	17531	17532	17533	17534	17535	17536	17537	17538	17539	17540	17541
17542	17543	17544	17545	17546	17547	17548	17549	17550	17551	17552	17553
17554	17555	17556	17557	17558	17559	17560	17561	17562	17563	17564	17565
17566	17567	17568	17569	17570	17571	17572	17573	17574	17575	17576	17577
17578	17579	17580	17581	17582	17583	17584	17585	17586	17587	17588	17589
17590	17591	17592	17593	17594	17595	17596	17597	17598	17599	17600	17601
17602	17603	17604	17605	17606	17607	17609	17610	17611	17612	17613	17614
17615	17616	17617	17618	17619	17630	17631	17632	17633	17634	17635	17636
17642	17643	17644	17645	17646	17647	17664	17665	17666	17667	17668	17669
17670	17671	17672	17673	17858	17859	17860	17861	17864	17865	17954	17955
17956	17957	17958	17959	17960	17961	17962	17963	17964	17965	17966	17967
17968	17969	17970	17971	17972	17976	17977	17978	17979	17980	17982	17983
17984	17985	17986	18009	18053	18054	18055	18056	18057	18058	18059	18060
18061	18062	18063	18066	18067	18068	18116	18119	18123	18134	18137	18153
18157	18158	18160	18174	18176	18185	18188	18191	18192	18193	18194	18195
18196	18197	18198	18199	18200	18201	18202	18203	18204	18205	18206	18207
18208	18209	18210	18211	18212	18213	18214	18215	18216	18217	18218	18219
18220	18221	18222	18223	18224	18225	18226	18227	18228	18229	18230	18231
18232	18233	18234	18235	18236	18237	18238	18239	18240	18241	18242	18243
18244	18245	18246	18247	18254	18259	18261	18262	18263	18265	18266	18268
18269	18270	18272	18274	18276	18277	18278	18329	18330	18331	18332	18333
18334	18335	18336	18337	18338	18341	18346	18353	18354	18356	18360	18451
18452	18453	18454	18455	18456	18457	18458	18459	18460	18463	18465	18467
18468	18472	18475	18476	18536	18577	18580	18581	18582	18583	18584	18585
18625	18626	18627	18628	18630	18632	18633	18645	18647	18649	18654	18655
18677	18684	18702	18709	18710	18711	18714	18729	18730	18731	18732	18733
18734	18735	18736	18737	18738	18739	18740	18741	18742	18752	18753	18754
18755	18756	18757	18758	18768	18769	18770	18771	18772	18773	18774	18775
18777	18778	18779	18778	18783	18786	18787	18788	18790	18791	18792	18793

18794	18795	18796	18803	18804	18805	18806	18807	18808	18809	18810	18811
18812	18813	18814	18816	18817	18818	18819	18821	18822	18829	18830	18832
18833	18837	18838	18839	18840	18843	18844	18845	18846	18852	18853	18854
18855	18856	18857	18858	18859	18860	18861	18862	18885	18886	18888	18889
18890	18891	18892	18902	18903	18904	18905	18906	18923	18931	18941	18942
18943	18948	18981	18991	19017	19018	19019	19020	19021	19022	19053	19057
19126	19127	19128	19129	19130	19131	19135	19146	19147	19151	19152	19157
19169	19170	19171	19185	19192	19263	19267	19268	19269	19270	19272	19288
19289	19291	19292	19297	19298	19299	19303	19304	19310	19311	19312	19313
19314	19315	19316	19317	19318	19319	19321	19322	19323	19324	19325	19326
19327	19329										
										Total:	3,386

Table 9A-8. Persons of Faith

11377	11378	11379	11380	11383	11384	11386	11387	11388	11389	11391	11392
11394	11395	11413	11414	11415	11416	11417	11421	11422	11423	11424	11425
11427	11532	11536	11882	11884	11885	11886	11887	11888	11996	11997	11998
12000	12001	12004	12065	12066	12068	12090	12093	12129	12132	12171	12417
12464	12719	12836	13537	13640	14027	16094	16095	16096	16097	16098	16099
16101	16102	16114	16115	16116	16126	16166	16213	16225	16231	16311	16323
16352	16555	16556	16557	16558	16559	16561	16564	16569	16584	16585	16586
16588	16589										
										Total:	86

Table 9A-9. Green Peace

5911	5913	6639	10646	10651	10758	10766	10767	10811	10813	10847	10848
10849	10850	10851	10852	10853	10854	10855	10856	10857	10858	10859	10860
10861	10862	10869	10870	10871	10872	10873	10874	10875	10876	10877	10878
10879	10880	10881	10882	10883	10884	10885	10886	10887	10888	10889	10890
10891	10892	10893	10894	10895	10896	10897	10898	10899	10900	10901	10903
10904	10905	10907	10908	10909	10910	10911	10912	10913	10915	10916	10917
10918	10919	10920	10921	10922	10923	10924	10925	10926	10927	10928	10929
10930	10931	10932	10933	10934	10935	10936	10937	10938	10939	10940	10941
10945	10946	10947	10948	10949	10950	10951	10952	10953	10954	10955	10956
10957	10958	10959	10960	10961	10962	10963	10964	10965	10966	10967	10968
10969	10970	10971	10972	10973	10974	10975	10976	10977	10978	10979	10980
10981	10982	10983	10984	10985	10986	10988	10989	10990	10991	10992	10993
10994	10995	10996	10995	10998	10999	11000	11001	11002	11003	11004	11005
11006	11007	11008	11009	11010	11011	11012	11013	11014	11015	11016	11017
11018	11019	11020	11021	11022	11023	11024	11025	11026	11027	11028	11029
11030	11031	11032	11033	11034	11035	11036	11037	11038	11039	11040	11041
11042	11043	11044	11045	11046	11047	11048	11049	11050	11051	11052	11054

11055	11057	11058	11059	11060	11061	11062	11063	11068	11069	11070	11071
11072	11073	11074	11075	11076	11077	11078	11079	11080	11081	11088	11089
11090	11091	11092	11093	11094	11095	11097	11098	11099	11100	11101	11102
11103	11709	12625	12674	12890	13052	14001	14002	14246			
										Total:	249

Table 9A-10. Full Support

16177	16220	16242	16319	17151	18659	18665	18667
						Total:	8

Table 9A-11. League of Conservation Voters

5465	9382
Total:	2

Table 9A-12. Natural Resources Council of Maine

4077	4078	4079	4080	4081	4082	4083	4084	4085	4086	4195	4197
4198	4199	4201	4202	4203	4204	4205	4206	4207	4208	4209	4213
4239	4240	4267	4269	4270	4271	4272	4273	4374	4462	4554	5146
5163	5432	6635	12287	12355	12356	13697	14669	15676	15926	16439	16440
16441	16442	16443	16444	16445	16446	16447	16449	16451	16470	16471	16472
16473	16474	16475	16479	16541	16545	17231	17284	17285	17286	17287	17314
17322	17325										
										Total:	74

Table 9A-13. Natural Resources Defense Council (NRDC)

12645	12875	13084	13085	13089	13090	13091	13092	13093	13097	13100	13101
13105	13106	13148	13150	13190	13191	13192	13193	13255	13256	13264	13265
13266	13272	13273	13299	13300	13301	13331	13332	13336	13337	13347	13348
13349	13350	13351	13352	13354	13355	13356	13357	13359	13360	13361	13362
13366	13367	13368	13369	13370	13371	13372	13373	13374	13376	13377	13378
13379	13384	13386	13387	13388	13389	13390	13391	13392	13393	13394	13395
13396	13397	13401	13406	13407	13408	13412	13413	13414	13415	13416	13417
13418	13427	13428	13429	13430	13431	13444	13445	13446	13447	13459	13464
13465	13468	13496	13497	13508	13509	13510	13511	13517	13536	13538	13540
13541	13547	13564	13566	13569	13570	13572	13573	13603	13604	13605	13606
13609	13611	13612	13613	13614	13621	13622	13623	13624	13629	13630	13631
13632	13635	13639	13644	13672	13673	13674	13690	13691	13693	13694	13796
13797	13798	13799	13798	14019	14025	14033	14046	14047	14071	14077	14122
14135	14139	14140	14144	14149	14160	14170	14171	14202	14394	14721	14804
15173	15197	15281	15285	15321	15339	15341	15914	16522	16525	17144	17145
17149	17150	18396	18398	18403	18407	18412	18635	18636	18913		

Total:	190

Table 9A-14. National Wildlife Federation (NWF)

3852	3860	3868	3882	3883	3894	3899	4087	4088	4089	4090	4091
4092	4093	4094	4095	4096	4097	4098	4154	4155	4156	4157	4158
4159	4160	4161	4163	4164	4165	4166	4210	4211	4212	4214	4215
4237	4297	4366	4367	4368	4369	4370	4371	4372	4373	4375	4376
4401	4411	4434	4439	4440	4441	4448	4449	4494	4495	4496	4502
4525	4526	4535	4536	4541	4544	4545	4563	4565	4571	4580	4600
4601	4607	4615	4618	4627	4642	4644	4645	4665	4666	4667	4668
4672	4674	4678	4688	4689	4690	4697	4732	4826	4827	4923	4925
4932	4959	4971	5001	5002	5003	5004	5019	5020	5021	5022	5023
5024	5025	5056	5057	5068	5076	5077	5078	5084	5102	5103	5104
5120	5140	5141	5176	5184	5242	5243	5244	5246	5265	5266	5281
5282	5286	5294	5303	5304	5317	5319	5320	5329	5428	5429	5430
5431	5433	5434	5433	5436	5437	5438	5439	5440	5441	5442	5443
5444	5445	5451	5469	5470	6177	6694	9710	9976	10001	10010	10028
11056	11138	11445	11533	12100	12109	12111	12142	12178	12184	12186	12187
12193	12216	12289	12299	12301	12308	12332	12341	12344	13698	13710	13803
13884	13885	13886	13887	13889	13890	13891	13892	13893	13894	13895	13896
13897	13898	13899	13900	13901	13903	13904	13905	13906	13909	13910	13911
13912	13913	13914	13915	13916	13917	13918	13920	13921	13922	13924	13925
13926	13927	13928	13929	13930	13931	13933	13934	13935	13936	13937	13938
13939	13940	13941	13942	13943	13944	13945	13946	13947	13948	13949	13950
13951	13952	13953	13954	13955	13956	13957	13958	13959	13960	13962	13963
13964	13984	13985	13986	13987	13988	13989	13990	13991	13992	13993	13994
13995	13996	13997	13998	13999	14000	14421	14426	14435	14436	14437	14462
14463	14464	14465	14466	14467	14468	14469	14470	14471	14472	14473	14474
14475	14476	14477	14479	14502	14505	14510	14661	14665	15402	15433	15434
15435	15436	15437	15438	15440	15441	15442	15443	15445	15446	15514	15515
15516	15517	15518	15548	15549	15550	15551	15552	15557	15558	15559	15786
15813	15920	15931	15932	15934	15956	15959	15961	16380	16384	16551	17234
17324	17653	19606	19612								
										Total:	352

Table 9A-15. Ohio Citizens Action

17239	17240	17245	17257	17258	17259	17260	17261	17262	17263	17264	17266
18309	18310	18312	18314	18318	18321	18322	18328	18373	18374	18378	18380
18383	18384	18386	18387	18393	18402	18404	18408	18542	18549	18564	18602
18603	18605	18607	18617	18619	18660	18681	18848	18863	18864	18866	18868
18870	18872	18873	18876	18877	19005	19007	19034	19038	19197	19200	19208
19218	19219	19222	19230	19231	19235	19243	19251	19254	19520	19522	19526

19533	19535	19542	19545	19547	19548	19551	19555	19558	19587		
										Total:	82

Table 9A-16. Our Families

4149	5214	5241	5576	5648	7063	7064	7065	7066	7067	7068	7069
7070	7071	7072	7073	7074	7075	7076	7089	7090	7091	7092	7093
7094	7095	7096	7097	7098	7099	7100	7101	7102	7103	7104	7105
7106	7107	7108	7109	7110	7111	7112	7113	7114	7115	7116	7117
7118	7119	7120	7121	7122	7123	7135	7136	7245	7246	7247	7248
7249	7250	7251	7252	7253	7257	7258	7259	7260	7261	7262	7263
7264	7265	7266	7267	7268	7269	7270	7271	7272	7273	7274	7275
7276	7277	7278	7279	7280	7281	7282	7283	7284	7285	7286	7287
7288	7289	7290	7291	7292	7293	7294	7295	7296	7297	7298	7299
7300	7301	7306	7307	7308	7309	7310	7311	7312	7313	7314	7315
7316	7317	7318	7319	7320	7321	7322	7323	7324	7325	7326	7327
7328	7329	7330	7331	7332	7333	7334	7335	7336	7337	7338	7339
7340	7341	7342	7341	7344	7359	7360	7361	7362	7363	7364	7365
7366	7367	7368	7369	7370	7371	7372	7373	7374	7375	7376	7377
7378	7379	7380	7381	7382	7383	7384	7385	7386	7387	7388	7389
7390	7391	7392	7393	7394	7395	7396	7397	7398	7399	7400	7401
7402	7403	7404	7405	7406	7407	7408	7409	7410	7411	7412	7413
7414	7415	7416	7417	7418	7419	7420	7421	7422	7423	7424	7425
7426	7427	7428	7429	7430	7431	7432	7433	7434	7435	7436	7437
7438	7439	7440	7441	7442	7443	7444	7445	7446	7447	7448	7449
7450	7451	7452	7453	7454	7455	7456	7457	7458	7459	7460	7461
7462	7463	7464	7465	7466	7467	7468	7469	7470	7471	7472	7473
7474	7475	7476	7477	7478	7479	7480	7481	7482	7483	7484	7485
7486	7487	7488	7489	7490	7491	7492	7493	7494	7495	7535	7536
7537	7540	7541	7542	7543	7544	7545	7546	7547	7548	7549	7550
7551	7552	7553	7554	7555	7556	7557	7558	7559	7560	7561	7562
7563	7564	7565	7566	7567	7568	7569	7570	7571	7572	7573	7574
7575	7576	7577	7578	7579	7580	7581	7632	7633	7634	7635	7636
7637	7638	7639	7640	7641	7642	7643	7644	7645	7646	7647	7648
7649	7650	7651	7652	7660	7672	9102	9158	9325	9349	9505	9508
9510	9649	9730	9736	9737	9742	9807	10065	10160	11878	12406	12803
13617											
										Total:	385

Table 9A-17. Physicians for Social Responsibility

13107	13149	13315	13317	13322	13365	13375	13383	13411	13492	13493	13494
13555	13575	13578	13580	13600	13627	13636	13692	13695	14123	14132	15220
15227	15229	15250	15251	15253	15286	15320	15322	15345	15347	15348	15349

15350	15351	15495	15496	15526	15527	15528	15529	15530	15531	15533	15534
15831	16006	16026	16209								
										Total:	52

Table 9A-18. Salsa Labs

7129	9575	9733	10172	10194	10200	10201	10213	10214	10215	10659	10736
11299	11359	11364	11366	11368	11370	11371	11390	11402	11410	11411	11418
11419	11546	11547	11549	11550	11552	11554	11555	11556	11557	11558	11559
11560	11561	11562	11563	11564	11565	11566	11567	11569	11570	11571	11572
11573	11574	11576	11577	11578	11580	11581	11582	11583	11584	11585	11586
11588	11589	11590	11591	11592	11639	11640	11641	11642	11643	11651	11659
11660	11661	11665	11666	11702	11725	11763	11764	11790	11791	11832	11834
11835	11836	11837	11840	11841	11842	11858	11860	11865	11877	11891	11892
11894	11901	11902	11903	11904	11905	11914	11916	11917	11924	11927	11928
11935	11963	11967	11999	12002	12023	12049	12094	12151	12284	12416	12421
12438	12440	12441	12442	12443	12448	12449	12450	12457	12463	12466	12468
12474	12495	12507	12512	12519	12537	12539	12540	12551	12556	12573	12574
12584	12599	12609	12599	12624	12644	12654	12677	12678	12712	12714	12717
12718	12727	12769	12770	12772	12791	12802	12812	12815	12828	12891	12892
12894	12901	12979	13194	13326	13353	13382	13385	13400	13404	13435	13442
13443	13458	13475	13477	13483	13563	13568	13576	13579	13601	13615	14028
14029	14051	14052	14053	14054	14055	14056	14057	14058	14059	14060	14061
14063	14064	14067	14068	14074	14079	14080	14081	14082	14088	14097	14098
14099	14105	14108	14112	14113	14114	14121	14124	14136	14137	14150	14153
14154	14156	14157	14173	14174	14175	14176	14177	14181	14182	14183	14185
14190	14206	14207	14208	14209	14210	14211	14212	14213	14214	14215	14216
14217	14218	14219	14220	14221	14222	14223	14224	14225	14229	14231	14232
14234	14236	14237	14238	14240	14241	14242	14244	14245	14247	14248	14249
14250	14251	14252	14253	14254	14260	14261	14262	14263	14264	14267	14268
14271	14272	14274	14275	14301	14309	14310	14311	14312	14313	14314	14315
14316	14317	14318	14319	14325	14327	14328	14329	14330	14331	14332	14333
14334	14335	14336	14337	14338	14339	14340	14341	14342	14343	14344	14346
14348	14349	14350	14354	14358	14359	14365	14366	14367	14376	14377	14378
14379	14380	14381	14382	14386	14388	14395	14397	14398	14399	14400	14402
14403	14406	14407	14408	14409	14410	14411	14416	14429	14430	14440	14451
14460	14461	14486	14521	14522	14523	14524	14525	14526	14527	14528	14529
14530	14531	14532	14533	14534	14535	14536	14537	14538	14539	14540	14678
14725	14726	14763	14764	14765	14766	14792	14794	14796	14797	14798	14799
14800	14801	14806	14810	14811	14812	14833	14834	14835	14836	14837	14838
14839	14840	14842	14847	14848	14849	14850	14851	14852	14854	14904	15007
15009	15011	15018	15021	15022	15023	15043	15045	15046	15048	15049	15052
15053	15054	15056	15057	15058	15059	15061	15080	15082	15164	15170	15172
15174	15176	15212	15214	15217	15219	15221	15224	15225	15249	15273	15283

15335	15337	15344	15403	15408	15425	15448	15449	15450	15458	15460	15465
15483	15484	15485	15486	15487	15488	15489	15490	15491	15492	15519	15520
15523	15553	15570	15682	15685	15686	15687	15688	15689	15690	15691	15790
15892	15893	15910	15911	15912	15949	16005	16007	16008	16009	16010	16012
16013	16014	16024	16025	16027	16028	16030	16031	16032	16046	16047	16052
16053	16055	16075	16164	16165	16226	16227	16229	16230	16233	16236	16237
16238	16281	16297	16304	16306	16320	16515	16516	16518	16526	16527	16538
16539	16540	16552	16560	16568	16591	17073	17089	17142	17143	17148	17152
17374	17404	18280	18281	18282	18283	18284	18285	18289	18290	18291	18292
18293	18294	18295	18296	18297	18298	18299	18300	18303	18304	18305	18307
18308	18311	18315	18316	18317	18320	18323	18324	18325	18326	18327	18371
18372	18375	18376	18375	18381	18382	18385	18388	18389	18390	18391	18392
18394	18395	18397	18399	18400	18405	18409	18410	18411	18508	18509	18510
18512	18513	18514	18515	18516	18517	18518	18519	18520	18521	18522	18523
18524	18525	18526	18527	18528	18529	18530	18532	18533	18534	18535	18537
18543	18544	18545	18550	18555	18560	18561	18563	18567	18569	18573	18574
18599	18600	18601	18604	18606	18608	18609	18610	18611	18612	18613	18614
18618	18624	18634	18637	18673	18674	18675	18687	18701	18704	18744	18760
18761	18762	18763	18764	18765	18865	18875	18895	18896	18908	18909	18910
18911	18912	18915	18916	18919	18920	18921	18922	18938	18939	18946	18947
18949	18950	18951	18952	18953	18954	18956	18958	18967	18968	18970	19006
19008	19011	19012	19014	19015	19035	19036	19037	19188	19189	19193	19194
19201	19204	19207	19232	19234	19237	19245	19252	19253	19525	19530	19552
19553	19583	19585	19586								
										Total:	736

Table 9A-19. Sierra Club

3106	3107	3108	3109	3110	3111	3112	3113	3114	3115	3116	3117
3118	3119	3120	3183	3187	3189	3190	3191	3192	3193	3194	3195
3196	3197	3198	3200	3201	3204	3205	3206	3207	3209	3210	3211
3212	3214	3216	3218	3219	3221	3257	3342	3343	3344	3345	3346
3347	3348	3351	3352	3354	3355	3357	3363	3368	3369	3376	3377
3387	3394	3395	3396	3421	3422	3423	3445	3446	3447	3448	3449
3450	3451	3475	3479	3480	3481	3482	3483	3484	3485	3486	3487
3507	3589	3590	3591	3690	3691	3705	3748	3749	3752	3753	3754
3755	3770	3771	3796	3800	3801	3803	3804	3815	3816	3824	3825
3826	3831	3832	3837	3844	3850	3851	3857	3858	3867	3872	3873
3874	3880	3881	3892	3896	3898	3901	3902	3905	3906	3911	3912
3914	3916	3917	3918	3928	3929	3930	3931	3932	3940	4050	4051
4052	4054	4055	4054	4061	4062	4064	4066	4068	4069	4070	4072
4073	4130	4131	4132	4133	4134	4135	4136	4151	4152	4153	4344
4363	4364	4365	4523	4524	4557	4671	4684	4706	4718	4730	4770

4771	4772	4773	4774	4775	4776	4777	4778	4779	4780	4781	4782
4790	4791	4792	4793	4794	4799	4800	4801	4802	4803	4805	4806
4807	4813	4814	4815	4816	4817	4828	4829	4830	4831	4832	4833
4834	4835	4836	4837	4838	4839	4840	4841	4842	4843	4844	4845
4846	4847	4848	4849	4850	4851	4852	4853	4854	4855	4856	4857
4858	4859	4860	4861	4862	4863	4864	4865	4866	4867	4868	4869
4870	4871	4872	4873	4874	4875	4876	4877	4878	4879	4880	4881
4882	4883	4884	4885	4886	4887	4888	4889	4890	4891	4892	4893
4894	4895	4896	4897	4898	4899	4900	4901	4902	4903	4904	4905
4906	4907	4908	4909	4910	4911	4912	4913	4914	4915	4916	4917
4918	4919	4929	4934	4935	4936	4937	4938	4939	4940	4941	4943
4944	4945	4946	4947	4948	4949	4950	4951	4952	4953	4954	4955
4956	4957	4958	4960	4961	4962	4963	4964	4965	4966	4967	4968
4969	4970	4974	4975	4976	4977	4978	4979	4980	4981	4987	4988
4989	4990	4991	4992	4996	4997	4998	5008	5009	5010	5011	5012
5013	5015	5017	5018	5032	5033	5034	5035	5036	5037	5038	5039
5040	5041	5043	5044	5045	5046	5047	5048	5049	5050	5051	5052
5055	5058	5059	5060	5061	5062	5063	5064	5066	5067	5069	5070
5071	5072	5073	5074	5075	5079	5080	5081	5083	5088	5089	5090
5091	5092	5093	5094	5095	5096	5099	5100	5101	5109	5110	5111
5112	5113	5114	5115	5116	5117	5118	5119	5121	5123	5124	5126
5127	5128	5129	5130	5131	5132	5133	5134	5135	5136	5137	5139
5147	5148	5149	5150	5151	5152	5153	5154	5155	5156	5157	5160
5161	5164	5165	5166	5167	5168	5169	5170	5171	5172	5173	5177
5178	5179	5180	5181	5185	5186	5187	5188	5189	5194	5195	5197
5198	5199	5200	5201	5202	5208	5209	5210	5211	5213	5217	5218
5219	5220	5221	5222	5223	5224	5225	5226	5227	5228	5229	5230
5231	5232	5233	5234	5235	5236	5237	5238	5239	5240	5249	5250
5251	5252	5253	5254	5255	5256	5257	5258	5259	5260	5261	5262
5263	5270	5271	5272	5273	5274	5275	5276	5277	5278	5279	5283
5284	5285	5287	5288	5289	5290	5291	5292	5293	5296	5297	5298
5299	5300	5301	5302	5306	5307	5308	5309	5310	5311	5312	5313
5314	5315	5316	5322	5323	5324	5325	5326	5327	5328	5332	5333
5334	5335	5336	5337	5338	5339	5340	5341	5342	5343	5344	5347
5357	5358	5359	5358	5361	5362	5363	5364	5365	5366	5367	5368
5370	5371	5372	5373	5374	5375	5376	5377	5378	5379	5380	5381
5382	5383	5384	5385	5386	5387	5388	5389	5390	5391	5392	5393
5394	5395	5396	5397	5398	5399	5400	5401	5402	5403	5404	5405
5406	5407	5408	5409	5410	5411	5412	5417	5418	5419	5420	5421
5422	5423	5424	5425	5426	5427	5461	5462	5463	5464	5466	5467
5468	5471	5472	5473	5474	5475	5476	5477	5478	5479	5480	5481
5482	5483	5484	5485	5486	5487	5488	5489	5490	5491	5492	5493

5494	5495	5496	5497	5498	5499	5500	5501	5502	5503	5504	5505
5506	5507	5508	5509	5510	5511	5512	5513	5514	5515	5516	5519
5520	5521	5522	5523	5524	5525	5526	5527	5528	5529	5530	5531
5532	5533	5534	5535	5536	5537	5538	5539	5540	5541	5542	5543
5544	5545	5546	5547	5548	5549	5550	5551	5552	5553	5554	5555
5556	5557	5558	5561	5563	5564	5565	5566	5567	5568	5569	5570
5571	5572	5573	5574	5575	5577	5578	5579	5580	5581	5582	5583
5584	5585	5586	5587	5588	5589	5590	5591	5592	5593	5594	5595
5596	5597	5598	5599	5600	5601	5602	5603	5604	5605	5606	5607
5608	5609	5610	5611	5612	5613	5614	5615	5616	5617	5618	5619
5620	5621	5622	5623	5624	5625	5626	5627	5628	5629	5630	5631
5632	5633	5634	5635	5636	5637	5638	5639	5640	5641	5642	5643
5644	5645	5646	5647	5649	5650	5651	5652	5653	5654	5655	5656
5657	5658	5659	5660	5661	5662	5663	5664	5665	5666	5667	5668
5669	5670	5671	5672	5673	5674	5675	5676	5677	5678	5679	5680
5681	5682	5683	5684	5685	5686	5687	5688	5689	5690	5692	5693
5694	5695	5696	5697	5698	5699	5700	5714	5715	5716	5717	5718
5719	5720	5721	5722	5723	5724	5725	5726	5727	5728	5729	5730
5731	5732	5733	5734	5735	5736	5737	5738	5739	5740	5741	5742
5743	5744	5745	5746	5747	5748	5749	5754	5755	5756	5757	5758
5759	5760	5761	5762	5763	5764	5765	5766	5767	5768	5769	5770
5771	5772	5773	5774	5775	5776	5777	5778	5779	5780	5781	5782
5783	5784	5785	5786	5787	5788	5789	5790	5791	5792	5793	5794
5795	5796	5797	5798	5799	5800	5801	5802	5803	5804	5805	5806
5807	5808	5809	5810	5811	5812	5813	5816	5817	5818	5819	5821
5822	5823	5824	5825	5826	5827	5828	5829	5830	5831	5832	5833
5834	5835	5836	5837	5841	5842	5843	5844	5845	5846	5849	5850
5851	5853	5862	5863	5864	5865	5866	5867	5868	5869	5870	5871
5872	5873	5874	5875	5876	5877	5878	5879	5880	5881	5882	5883
5884	5885	5886	5885	5888	5889	5890	5891	5892	5893	5894	5895
5896	5897	5898	5899	5900	5901	5902	5903	5904	5905	5906	5907
5908	5909	5910	5912	5914	5915	5916	5917	5918	5919	5920	5921
5922	5923	5924	5925	5926	5927	5928	5929	5930	5931	5932	5933
5934	5935	5936	5937	5938	5939	5940	5941	5942	5943	5944	5945
5946	5947	5948	5949	5950	5951	5952	5953	5954	5955	5956	5957
5958	5959	5960	5961	5962	5963	5964	5965	5966	5967	5968	5969
5970	5971	5972	5973	5974	5975	5976	5977	5978	5979	5980	5981
5982	5983	5984	5985	5986	5987	5988	5989	5990	5991	5992	5993
5994	5995	5996	5997	5998	5999	6000	6001	6002	6003	6004	6005
6006	6007	6009	6010	6011	6012	6013	6014	6015	6016	6017	6018
6019	6020	6021	6022	6023	6024	6025	6026	6027	6028	6029	6030
6031	6032	6033	6034	6035	6036	6037	6038	6039	6040	6041	6042

6043	6044	6045	6046	6047	6048	6049	6050	6051	6052	6053	6055
6056	6057	6058	6059	6060	6061	6062	6063	6064	6065	6066	6067
6068	6069	6070	6071	6072	6073	6074	6075	6076	6077	6078	6079
6080	6081	6082	6083	6084	6085	6086	6087	6088	6089	6090	6091
6092	6093	6094	6095	6096	6097	6098	6099	6100	6101	6102	6103
6104	6105	6106	6107	6108	6109	6110	6111	6641	6642	6643	6644
6645	6646	6647	6648	6649	6650	6651	6652	6653	6654	6655	6656
6657	6658	6659	6660	6661	6662	6663	7124	7125	7126	7127	7128
7130	7131	7132	7133	7134	7137	7138	7139	7140	7141	7142	7143
7144	7145	7146	7147	7148	7149	7150	7151	7152	7153	7154	7155
7156	7157	7158	7159	7160	7161	7162	7163	7164	7165	7166	7167
7168	7169	7170	7171	7172	7173	7174	7175	7176	7177	7178	7179
7180	7181	7182	7183	7184	7185	7186	7187	7188	7189	7190	7191
7192	7193	7194	7195	7196	7197	7345	7589	7590	7591	7592	7593
7594	7595	7596	7597	7598	7599	7600	7601	7602	7603	7604	7605
7606	7607	7608	7609	7610	7611	7612	7613	7614	7615	7616	7617
7618	7619	7620	7621	7622	7623	7624	7625	7626	7627	7628	7629
7630	7631	7656	7657	7676	7677	7678	7679	7680	7681	7682	7683
7684	7685	7686	7687	7688	7689	7690	7691	7692	7693	7694	7695
7696	7697	7698	7699	7700	7701	7702	7703	7704	7705	7706	7707
7708	7709	7710	7711	7712	7713	7714	7715	7716	7717	7718	7719
7720	7721	7722	7723	7724	7725	7726	7727	7728	7729	7730	7731
7732	7733	7734	7735	7736	7737	7738	7739	7740	7741	7742	7743
7744	7745	7746	7748	7749	7750	7751	7752	7753	7754	7755	7756
7757	7758	7759	7758	7761	7762	7763	7764	7765	7766	7767	7768
7769	7770	7771	7772	7773	7774	7775	7776	7777	7778	7779	7780
7781	7782	7783	7784	7785	7786	7787	7788	7789	7790	7791	7792
7793	7794	7795	7796	7797	7798	7799	7800	7801	7802	7803	7804
7805	7806	7807	7808	7809	7810	7811	7812	7813	7814	7815	7816
7817	7818	7819	7820	7821	7822	7823	7824	7825	7826	7827	7829
7830	7831	7832	7833	7834	7835	7836	7837	7838	7839	7840	7841
7842	7843	7844	7845	7846	7847	7848	7849	7850	7851	7852	7853
7854	7855	7856	7857	7858	7860	7861	7862	7863	7864	7865	7866
7867	7868	7869	7870	7871	7872	7873	7874	7875	7876	7877	7878
7879	7880	7881	7882	7883	7884	7885	7886	7887	7888	7889	7890
7891	7892	7893	7894	7895	7896	7897	7898	7899	7900	7901	7902
7903	7904	7905	7906	7907	7908	7909	7910	7911	7912	7913	7914
7915	7916	7917	7918	7919	7920	7921	7922	7923	7924	7925	7926
7927	7928	7929	7930	7931	7932	7933	7934	7935	7936	7937	7938
7939	7940	7941	7942	7943	7944	7945	7946	7947	7948	7949	7950
7951	7952	7953	7954	7955	7956	7957	7958	7959	7960	7961	7962
7963	7964	7965	7966	7967	7968	7969	7970	7971	7972	7973	7974

7976	7977	7978	7979	7980	7981	7982	7983	7984	7985	7986	7988
7989	7990	7991	7992	7993	7994	7995	7996	7997	7998	7999	8000
8001	8002	8003	8004	8005	8006	8007	8008	8009	8010	8011	8012
8013	8014	8015	8016	8017	8018	8019	8020	8021	8022	8023	8024
8025	8026	8027	8028	8029	8030	8031	8032	8033	8034	8035	8036
8037	8038	8039	8040	8041	8042	8043	8044	8045	8046	8047	8048
8049	8050	8051	8052	8053	8054	8055	8056	8057	8058	8059	8060
8061	8062	8063	8064	8065	8066	8067	8068	8069	8070	8071	8072
8073	8074	8075	8076	8077	8078	8079	8080	8081	8082	8083	8084
8085	8086	8087	8088	8089	8090	8091	8092	8093	8094	8095	8096
8097	8098	8099	8100	8101	8102	8103	8104	8105	8106	8107	8108
8109	8110	8111	8112	8113	8114	8115	8116	8117	8118	8119	8120
8121	8122	8123	8124	8125	8126	8127	8128	8129	8130	8131	8132
8133	8134	8135	8136	8137	8138	8139	8140	8141	8142	8143	8144
8145	8146	8147	8148	8149	8150	8151	8152	8153	8154	8155	8156
8157	8158	8159	8160	8161	8162	8163	8164	8165	8166	8167	8168
8169	8170	8171	8172	8173	8174	8175	8176	8177	8178	8179	8180
8181	8182	8183	8184	8185	8186	8187	8188	8189	8190	8191	8192
8193	8194	8195	8196	8197	8198	8199	8200	8201	8202	8203	8204
8205	8206	8207	8206	8209	8210	8211	8212	8213	8214	8215	8216
8217	8218	8219	8220	8221	8222	8223	8224	8225	8226	8227	8228
8229	8230	8231	8232	8233	8234	8235	8236	8237	8238	8239	8240
8241	8242	8243	8244	8245	8246	8247	8248	8249	8250	8251	8252
8253	8254	8255	8258	8259	8260	8261	8262	8263	8264	8265	8266
8267	8268	8269	8270	8271	8272	8273	8274	8275	8276	8277	8278
8279	8280	8281	8282	8283	8284	8285	8286	8288	8289	8290	8291
8292	8293	8294	8295	8296	8297	8298	8299	8302	8303	8304	8305
8306	8307	8308	8309	8310	8311	8312	8313	8314	8315	8316	8317
8318	8319	8320	8321	8322	8323	8324	8325	8326	8327	8328	8329
8330	8331	8332	8333	8334	8335	8336	8337	8338	8339	8340	8341
8342	8343	8344	8345	8346	8347	8348	8349	8350	8351	8352	8353
8354	8355	8356	8357	8358	8359	8360	8361	8362	8363	8364	8365
8366	8367	8368	8369	8370	8371	8372	8373	8374	8375	8376	8377
8378	8379	8380	8381	8382	8383	8384	8385	8386	8387	8388	8389
8390	8391	8392	8393	8394	8395	8396	8397	8398	8399	8400	8401
8402	8403	8404	8405	8406	8407	8408	8409	8410	8411	8412	8413
8414	8415	8416	8417	8418	8419	8420	8421	8422	8423	8424	8425
8426	8427	8428	8429	8430	8431	8432	8433	8435	8436	8437	8438
8439	8440	8441	8442	8444	8445	8446	8447	8448	8449	8450	8451
8452	8453	8454	8455	8456	8457	8458	8459	8460	8461	8462	8463
8464	8465	8466	8467	8468	8469	8470	8471	8472	8473	8474	8475
8476	8477	8478	8479	8480	8481	8482	8483	8484	8485	8486	8487

8488	8489	8490	8491	8492	8493	8494	8495	8496	8497	8498	8499
8500	8501	8502	8503	8504	8505	8506	8507	8508	8509	8510	8511
8512	8513	8514	8515	8516	8517	8518	8519	8522	8523	8524	8525
8526	8527	8528	8529	8530	8531	8532	8533	8534	8535	8536	8537
8538	8539	8540	8541	8542	8543	8544	8545	8546	8547	8548	8549
8550	8551	8552	8553	8554	8555	8556	8557	8558	8559	8560	8561
8562	8563	8564	8565	8566	8567	8568	8569	8570	8571	8572	8573
8574	8575	8576	8577	8578	8589	8590	8591	8592	8593	8594	8595
8596	8597	8598	8599	8600	8601	8602	8603	8604	8605	8606	8607
8608	8609	8610	8611	8612	8613	8614	8615	8616	8617	8618	8619
8620	8621	8622	8623	8624	8625	8626	8627	8628	8629	8630	8631
8632	8633	8634	8635	8636	8637	8638	8639	8640	8641	8642	8643
8644	8645	8646	8647	8648	8649	8650	8651	8652	8653	8654	8655
8656	8657	8658	8659	8660	8661	8662	8663	8664	8665	8666	8667
8668	8669	8670	8669	8672	8673	8674	8675	8676	8677	8678	8679
8680	8681	8682	8683	8685	8686	8687	8688	8689	8690	8691	8692
8693	8694	8695	8696	8697	8698	8699	8700	8701	8702	8703	8704
8705	8706	8707	8708	8709	8710	8711	8712	8713	8714	8715	8716
8717	8718	8719	8720	8721	8722	8723	8724	8725	8726	8727	8728
8729	8730	8731	8732	8733	8734	8735	8736	8737	8738	8739	8740
8741	8742	8743	8744	8745	8746	8747	8748	8749	8750	8751	8752
8753	8754	8755	8756	8757	8758	8759	8760	8761	8762	8763	8764
8765	8766	8767	8768	8769	8770	8771	8772	8773	8774	8775	8776
8777	8778	8779	8780	8781	8782	8783	8784	8785	8786	8787	8788
8789	8790	8791	8792	8793	8794	8795	8796	8797	8798	8799	8800
8801	8802	8803	8804	8805	8806	8807	8808	8809	8810	8811	8812
8813	8814	8815	8816	8817	8818	8819	8820	8821	8822	8823	8824
8825	8826	8827	8828	8829	8830	8831	8832	8833	8834	8835	8836
8837	8838	8839	8840	8841	8842	8843	8844	8845	8846	8847	8848
8849	8850	8851	8852	8853	8854	8855	8856	8857	8858	8859	8860
8861	8862	8863	8864	8865	8866	8867	8868	8869	8870	8871	8880
8881	8882	8883	8884	8885	8886	8887	8888	8889	8890	8891	8892
8893	8894	8895	8896	8897	8898	8899	8900	8901	8902	8903	8904
8905	8906	8907	8908	8909	8910	8911	8912	8913	8914	8915	8916
8917	8918	8919	8920	8921	8922	8923	8924	8925	8926	8927	8928
8929	8930	8931	8932	8933	8934	8935	8936	8937	8938	8939	8940
8941	8942	8943	8944	8945	8946	8947	8948	8949	8950	8951	8952
8953	8954	8955	8956	8957	8959	8960	8962	8963	8964	8965	8966
8967	8968	8969	8970	8971	8972	8973	8974	8975	8976	8977	8978
8979	8980	8981	8982	8983	8984	8985	8986	8987	8988	8989	8990
8991	8992	8993	8994	8995	8996	8997	8998	8999	9000	9001	9002
9003	9004	9005	9006	9007	9008	9009	9010	9011	9012	9013	9014

9015	9016	9017	9018	9019	9020	9021	9023	9024	9025	9026	9027
9028	9029	9030	9031	9032	9033	9034	9035	9036	9037	9038	9039
9040	9041	9042	9043	9044	9045	9046	9047	9048	9049	9050	9051
9052	9053	9054	9055	9056	9057	9058	9059	9060	9061	9062	9063
9064	9065	9066	9067	9068	9069	9070	9071	9073	9074	9075	9076
9077	9078	9079	9080	9081	9082	9083	9084	9085	9086	9087	9088
9089	9090	9091	9092	9093	9094	9095	9096	9097	9098	9099	9100
9101	9103	9104	9105	9106	9107	9108	9109	9110	9111	9113	9114
9115	9116	9117	9119	9120	9121	9122	9123	9124	9125	9126	9127
9128	9129	9130	9129	9132	9133	9134	9135	9136	9137	9138	9139
9140	9141	9142	9143	9144	9145	9146	9147	9148	9149	9150	9151
9152	9153	9155	9156	9157	9160	9161	9162	9163	9164	9165	9166
9167	9168	9169	9170	9171	9173	9218	9219	9220	9286	9287	9288
9289	9290	9291	9292	9293	9294	9295	9296	9297	9345	9347	9348
9350	9351	9352	9353	9354	9355	9356	9357	9358	9359	9360	9361
9362	9363	9364	9365	9366	9367	9368	9369	9370	9371	9372	9373
9374	9375	9377	9378	9379	9380	9381	9383	9384	9385	9386	9387
9388	9389	9390	9391	9392	9393	9394	9395	9396	9397	9398	9399
9400	9401	9402	9403	9404	9405	9406	9407	9408	9409	9410	9411
9412	9413	9414	9415	9416	9417	9418	9419	9420	9421	9422	9423
9424	9425	9426	9427	9428	9429	9448	9466	9467	9468	9484	9497
9499	9507	9509	9512	9514	9523	9616	9728	9729	9731	9734	9735
9739	9740	9741	9745	9746	9747	9748	9750	9751	9752	9753	9771
9772	9773	9774	9775	9776	9777	9778	9779	9780	9781	9782	9783
9784	9785	9786	9787	9788	9789	9791	9792	9793	9794	9795	9796
9797	9798	9799	9800	9801	9802	9803	9804	9850	9851	9852	9853
9856	9857	9861	9865	9905	9906	9908	9910	9911	9912	9913	9914
9915	9916	9917	9918	9922	9923	9924	9925	9926	9927	9928	9929
9930	9935	9936	9937	9938	9945	9948	9949	9950	9952	9954	9955
9956	9957	9960	9961	10030	10031	10032	10033	10034	10035	10036	10037
10038	10039	10040	10042	10043	10044	10045	10046	10047	10048	10049	10050
10051	10052	10053	10054	10055	10056	10057	10058	10059	10060	10061	10062
10063	10064	10066	10067	10068	10069	10070	10071	10072	10073	10074	10075
10076	10077	10078	10079	10080	10081	10082	10083	10084	10085	10086	10087
10088	10089	10090	10091	10092	10093	10094	10095	10096	10097	10098	10101
10102	10103	10105	10107	10108	10111	10112	10113	10123	10124	10127	10129
10130	10131	10132	10133	10134	10135	10136	10137	10138	10139	10140	10141
10142	10143	10144	10145	10146	10147	10148	10149	10150	10151	10152	10153
10154	10155	10156	10157	10158	10159	10161	10162	10163	10164	10168	10171
10173	10174	10175	10176	10177	10178	10179	10180	10181	10183	10184	10185
10186	10187	10188	10189	10190	10191	10192	10193	10195	10196	10197	10198
10199	10202	10203	10204	10205	10206	10207	10208	10209	10210	10211	10212

10216	10217	10218	10219	10220	10221	10222	10223	10224	10225	10226	10227
10228	10229	10230	10231	10232	10233	10234	10235	10236	10237	10238	10239
10240	10241	10242	10243	10244	10245	10246	10247	10248	10249	10250	10251
10252	10253	10254	10255	10256	10257	10258	10259	10260	10261	10262	10263
10264	10265	10266	10265	10268	10269	10270	10271	10272	10273	10274	10275
10276	10277	10278	10279	10280	10281	10282	10283	10284	10285	10286	10287
10288	10289	10290	10291	10292	10293	10294	10295	10296	10297	10298	10299
10300	10301	10302	10303	10304	10305	10306	10307	10308	10309	10310	10311
10312	10313	10314	10315	10316	10317	10318	10319	10320	10321	10322	10323
10324	10325	10326	10327	10328	10329	10330	10331	10332	10333	10334	10335
10336	10337	10338	10339	10340	10341	10342	10343	10344	10345	10346	10347
10348	10349	10350	10351	10352	10353	10354	10355	10356	10357	10358	10359
10360	10361	10362	10363	10364	10365	10366	10367	10368	10369	10370	10371
10372	10373	10374	10375	10376	10377	10378	10379	10380	10381	10382	10383
10384	10385	10386	10387	10388	10389	10390	10391	10392	10393	10394	10395
10396	10397	10398	10399	10400	10401	10402	10403	10404	10405	10406	10407
10408	10409	10410	10411	10412	10413	10414	10415	10416	10417	10418	10419
10420	10421	10422	10423	10424	10425	10426	10427	10428	10429	10430	10431
10432	10433	10434	10435	10436	10437	10438	10439	10440	10441	10442	10443
10444	10445	10446	10447	10448	10449	10450	10451	10452	10453	10454	10455
10456	10457	10458	10459	10460	10461	10462	10463	10464	10465	10466	10467
10468	10469	10470	10471	10472	10473	10474	10475	10476	10477	10478	10479
10480	10481	10482	10483	10484	10485	10486	10487	10488	10489	10490	10491
10492	10493	10494	10495	10496	10497	10498	10499	10500	10501	10502	10503
10504	10505	10506	10507	10508	10509	10510	10511	10512	10513	10514	10515
10516	10517	10518	10519	10520	10523	10524	10525	10526	10527	10528	10529
10530	10531	10532	10533	10534	10535	10536	10537	10538	10539	10540	10541
10542	10543	10544	10545	10546	10547	10548	10549	10550	10551	10552	10553
10554	10555	10556	10557	10558	10559	10560	10561	10562	10563	10564	10565
10566	10567	10568	10570	10571	10572	10573	10574	10575	10576	10577	10578
10579	10580	10581	10582	10583	10584	10585	10586	10587	10588	10589	10590
10591	10592	10593	10594	10595	10596	10597	10598	10599	10600	10601	10602
10603	10604	10605	10606	10607	10608	10609	10611	10612	10613	10614	10615
10616	10617	10618	10619	10620	10621	10622	10624	10625	10626	10627	10628
10629	10630	10631	10632	10633	10634	10635	10636	10638	10639	10640	10641
10642	10643	10644	10645	10647	10648	10649	10650	10652	10653	10654	10655
10656	10657	10658	10661	10662	10663	10664	10665	10666	10667	10668	10669
10670	10671	10672	10673	10674	10675	10676	10677	10678	10679	10680	10681
10682	10683	10684	10685	10686	10687	10688	10689	10690	10691	10692	10693
10694	10695	10696	10697	10698	10699	10700	10701	10702	10703	10704	10705
10706	10707	10708	10709	10710	10711	10712	10713	10714	10715	10716	10717
10718	10719	10720	10719	10722	10723	10724	10725	10726	10727	10728	10730

10731	10733	10735	10737	10738	10739	10740	10741	10742	10743	10744	10745
10746	10747	10748	10749	10751	10752	10753	10754	10755	10756	10759	10760
10761	10763	10764	10765	10768	10769	10770	10771	10772	10773	10774	10775
10776	10777	10778	10779	10780	10781	10782	10783	10784	10785	10786	10787
10788	10789	10790	10791	10792	10793	10794	10795	10796	10797	10798	10799
10800	10801	10802	10803	10804	10805	10806	10807	10808	10809	10810	10812
10814	10815	10816	10817	10818	10819	10820	10823	10824	10825	10826	10829
10830	10831	10832	10833	10834	10835	10836	10837	10838	10839	10840	10841
10842	10843	10844	10845	10846	10863	10864	10865	10866	10867	10868	10914
11082	11083	11084	11085	11086	11087	11282	11283	11284	11289	11290	11291
11292	11293	11294	11295	11296	11297	11300	11301	11302	11303	11304	11305
11306	11307	11308	11309	11310	11311	11312	11313	11315	11316	11317	11318
11319	11320	11321	11322	11323	11324	11325	11326	11327	11328	11329	11330
11331	11332	11333	11334	11335	11336	11337	11338	11339	11340	11341	11342
11343	11344	11345	11346	11347	11348	11349	11350	11353	11354	11355	11356
11357	11358	11360	11361	11362	11363	11365	11367	11369	11372	11375	11376
11381	11385	11397	11398	11399	11400	11405	11406	11407	11408	11409	11412
11420	11428	11429	11430	11431	11432	11433	11434	11435	11436	11437	11438
11449	11450	11451	11452	11453	11454	11455	11456	11457	11458	11459	11460
11461	11462	11463	11464	11465	11466	11467	11468	11469	11470	11471	11472
11473	11474	11475	11476	11478	11479	11480	11481	11482	11483	11484	11485
11486	11487	11488	11489	11490	11491	11492	11493	11494	11495	11496	11497
11498	11499	11500	11501	11502	11503	11504	11505	11506	11507	11508	11509
11510	11511	11512	11513	11514	11515	11516	11517	11518	11519	11520	11521
11522	11523	11524	11525	11526	11527	11537	11538	11539	11540	11541	11542
11543	11544	11545	11548	11551	11553	11568	11575	11579	11587	11593	11594
11595	11604	11621	11625	11629	11631	11632	11637	11638	11646	11649	11650
11652	11657	11658	11662	11663	11664	11668	11696	11697	11698	11699	11700
11701	11704	11705	11713	11714	11715	11716	11717	11718	11719	11720	11721
11722	11723	11724	11726	11727	11729	11730	11731	11732	11733	11734	11735
11736	11737	11738	11739	11740	11741	11742	11743	11744	11745	11746	11747
11748	11749	11750	11751	11752	11753	11754	11755	11756	11758	11759	11760
11761	11762	11765	11766	11773	11774	11775	11776	11777	11778	11779	11780
11781	11786	11787	11788	11789	11796	11797	11798	11799	11800	11817	11818
11819	11820	11821	11822	11823	11824	11825	11826	11827	11828	11829	11830
11831	11833	11838	11839	11843	11845	11859	11861	11866	11875	11880	11895
11925	11926	11929	11926	11934	11936	11937	11938	11939	11950	11956	11957
11958	11959	11960	11961	11962	11964	11965	11966	11968	11995	12005	12006
12010	12015	12016	12017	12018	12019	12020	12021	12034	12044	12052	12057
12058	12063	12064	12069	12070	12071	12074	12075	12076	12081	12082	12088
12089	12092	12096	12097	12098	12123	12124	12125	12126	12127	12130	12145
12146	12147	12149	12150	12153	12154	12170	12172	12201	12202	12229	12233

12239	12240	12242	12243	12244	12245	12246	12247	12248	12249	12250	12251
12263	12266	12279	12280	12282	12385	12386	12387	12388	12389	12390	12391
12392	12393	12394	12395	12396	12397	12398	12399	12400	12401	12403	12404
12407	12408	12410	12412	12413	12414	12415	12419	12420	12422	12423	12424
12426	12427	12428	12429	12432	12433	12434	12435	12436	12437	12444	12445
12446	12447	12451	12452	12453	12454	12455	12456	12458	12465	12469	12470
12471	12472	12473	12475	12476	12477	12478	12479	12480	12481	12482	12483
12484	12485	12486	12487	12488	12489	12490	12491	12492	12493	12494	12496
12497	12498	12499	12500	12501	12502	12514	12515	12516	12517	12522	12523
12524	12527	12528	12529	12530	12531	12538	12541	12542	12543	12544	12545
12549	12550	12552	12553	12554	12555	12557	12558	12559	12575	12576	12577
12578	12579	12580	12581	12582	12583	12585	12586	12587	12588	12590	12591
12592	12593	12594	12595	12596	12597	12598	12600	12601	12602	12603	12604
12605	12606	12607	12608	12610	12611	12612	12613	12614	12616	12623	12631
12632	12633	12634	12635	12636	12637	12638	12640	12641	12642	12643	12646
12647	12655	12656	12657	12658	12659	12660	12666	12667	12668	12669	12670
12671	12672	12680	12681	12688	12689	12690	12691	12692	12693	12694	12695
12696	12697	12698	12699	12700	12701	12702	12703	12713	12721	12726	12728
12729	12730	12731	12732	12733	12734	12735	12736	12737	12738	12739	12740
12741	12742	12743	12744	12745	12746	12747	12748	12749	12750	12751	12752
12753	12754	12771	12773	12774	12775	12776	12777	12778	12779	12781	12782
12783	12784	12785	12786	12787	12788	12789	12790	12792	12804	12805	12806
12808	12809	12810	12811	12813	12817	12818	12819	12820	12821	12822	12823
12824	12825	12826	12827	12829	12830	12831	12832	12833	12834	12835	12837
12838	12839	12840	12841	12842	12843	12844	12845	12846	12847	12848	12849
12850	12851	12852	12853	12854	12855	12856	12857	12858	12859	12860	12861
12862	12863	12864	12865	12866	12867	12868	12869	12870	12871	12872	12873
12874	12876	12877	12878	12879	12880	12882	12883	12884	12885	12893	12895
12897	12898	12899	12900	12902	12903	12904	12905	12906	12907	12908	12909
12910	12911	12912	12913	12914	12915	12916	12917	12918	12919	12920	12921
12922	12923	12924	12925	12926	12927	12928	12929	12930	12931	12932	12933
12934	12935	12936	12935	12938	12939	12940	12941	12942	12943	12944	12945
12946	12947	12972	12973	12974	12975	12978	12980	12981	12982	12983	12984
12985	12986	12990	12993	12997	12998	12999	13000	13001	13002	13003	13004
13009	13011	13012	13013	13014	13015	13016	13017	13018	13019	13020	13021
13022	13023	13024	13025	13026	13027	13028	13030	13031	13032	13033	13034
13035	13036	13037	13038	13039	13040	13041	13042	13043	13044	13045	13046
13047	13048	13049	13050	13051	13053	13054	13057	13058	13064	13065	13066
13067	13068	13069	13070	13071	13072	13073	13074	13075	13076	13077	13078
13079	13080	13081	13082	13083	13086	13087	13088	13094	13095	13096	13098
13102	13103	13104	13108	13111	13113	13114	13115	13116	13123	13124	13125
13129	13130	13135	13136	13142	13143	13144	13145	13146	13147	13155	13156

13157	13158	13160	13161	13162	13173	13174	13175	13176	13177	13219	13220
13221	13222	13223	13224	13225	13231	13232	13233	13245	13246	13247	13248
13249	13254	13260	13261	13262	13263	13274	13275	13277	13278	13279	13280
13281	13282	13283	13284	13285	13286	13287	13288	13289	13290	13291	13292
13293	13294	13295	13296	13297	13298	13316	13318	13319	13320	13321	13323
13324	13327	13328	13329	13330	13333	13334	13335	13338	13339	13340	13341
13342	13343	13344	13345	13346	13358	13363	13364	13380	13381	13403	13405
13409	13410	13422	13423	13424	13425	13426	13436	13437	13438	13439	13440
13441	13467	13470	13471	13473	13474	13476	13481	13482	13484	13485	13486
13487	13488	13489	13490	13491	13499	13500	13501	13502	13503	13504	13505
13506	13507	13516	13535	13542	13543	13565	13567	13571	13574	13577	13581
13582	13583	13584	13585	13586	13587	13588	13602	13607	13608	13610	13616
13618	13625	13626	13628	13633	13634	13637	13638	13641	13642	13643	13689
13795	14018	14021	14024	14026	14030	14031	14032	14048	14049	14062	14078
14083	14084	14089	14090	14103	14104	14111	14120	14125	14131	14143	14147
14151	14155	14158	14159	14161	14162	14163	14167	14169	14172	14184	14188
14189	14196	14197	14198	14199	14200	14203	14204	14226	14390	14391	14392
14393	14404	14405	14762	14795	15008	15015	15024	15051	15081	15180	15210
15274	15282	15332	15338	15536	15556	15894	16001	16029	16128	16129	16131
16132	16133	16134	16135	16136	16147	16148	16150	16151	16153	16155	16156
16157	16158	16210	16211	16216	16235	16283	16298	16299	16303	16322	16345
16514	16520	16521	16523	16524	16590	17072	17074	17083	17084	17085	17087
17088	17141	18553	18562	18570	18572	18700	19523	19524	19528	19532	19534
19543	19546	19557	19563	19570	19571	19572	19613	19636	19637	19638	19639
19640	19641	19642	19663	19664	19665	19672	19673	19674	19675		
										Total:	5,014

Table 9A-20. Union of Concerned Scientists

3121	3122	3123	3124	3125	3126	3127	3128	3129	3130	3131	3132
3133	3134	3135	3136	3137	3161	3162	3163	3164	3165	3166	3167
3168	3169	3170	3171	3172	3173	3174	3175	3176	3177	3178	3179
3180	3181	3182	3184	3185	3186	3199	3202	3203	3208	3213	3215
3217	3220	3222	3225	3226	3227	3228	3229	3230	3231	3232	3233
3234	3235	3236	3237	3238	3239	3240	3241	3242	3243	3244	3245
3271	3272	3273	3274	3310	3311	3312	3313	3314	3332	3333	3337
3338	3339	3340	3341	3349	3350	3353	3356	3359	3360	3362	3365
3370	3382	3386	3388	3391	3424	3425	3426	3427	3428	3429	3430
3431	3432	3433	3434	3435	3452	3453	3462	3463	3464	3465	3466
3467	3468	3469	3470	3471	3472	3473	3474	3476	3477	3478	3488
3489	3490	3491	3492	3493	3508	3509	3511	3514	3520	3521	3522
3523	3524	3525	3524	3527	3528	3529	3530	3531	3532	3533	3534
3535	3536	3537	3538	3539	3540	3541	3542	3543	3544	3545	3546

3547	3548	3559	3560	3561	3562	3563	3564	3565	3566	3568	3588
3750	3751	3772	3797	3798	3799	3802	3845	3846	3859	3865	3866
3887	3888	3889	3891	3897	3903	3904	3909	3910	3913	3915	3919
3920	3926	3927	3933	3934	3935	3936	3937	3948	4053	4057	4058
4059	4060	4063	4065	4067	4071	4150	4342	4343	4673	4677	4685
4686	4687	4705	4930	4972	4973	4984	4985	4986	4994	4995	5016
5086	5087	5105	5106	5107	5108	5125	5143	5144	5145	5162	5196
5215	5248	5814	5815	5820	5838	5839	5840	5848	5858	5859	5860
5861	6008	6054	7987	9174	9175	9176	9177	9178	9179	9180	9181
9182	9183	9184	9185	9186	9187	9188	9189	9190	9191	9192	9193
9194	9195	9196	9197	9198	9199	9200	9201	9202	9203	9204	9205
9206	9207	9208	9209	9210	9211	9212	9213	9214	9215	9216	9217
9221	9222	9223	9224	9225	9226	9227	9228	9229	9230	9231	9232
9233	9234	9235	9236	9237	9238	9239	9240	9241	9242	9243	9244
9245	9246	9247	9248	9249	9250	9251	9252	9253	9254	9255	9256
9257	9258	9259	9260	9261	9262	9263	9264	9265	9266	9267	9277
9278	9279	9280	9281	9282	9283	9284	9285	9298	9299	9300	9301
9302	9303	9304	9305	9306	9307	9308	9309	9310	9311	9312	9313
9314	9315	9316	9317	9318	9319	9320	9321	9322	9323	9324	9326
9327	9328	9329	9330	9331	9332	9333	9334	9335	9336	9337	9338
9339	9340	9341	9342	9343	9344	9346	9430	9431	9432	9433	9434
9435	9436	9437	9438	9439	9440	9441	9442	9443	9444	9445	9446
9447	9449	9450	9451	9452	9453	9454	9455	9456	9457	9458	9459
9495	9496	9498	9500	9501	9502	9503	9504	9506	9511	9513	9515
9516	9517	9615	9665	9700	9715	9732	9744	9749	9754	9755	9756
9757	9758	9759	9760	9761	9762	9763	9764	9805	9806	9808	9809
9810	9811	9812	9813	9814	9815	9816	9817	9818	9819	9820	9821
9822	9823	9824	9825	9826	9827	9828	9829	9830	9831	9832	9833
9834	9835	9836	9837	9838	9839	9840	9841	9842	9843	9844	9845
9846	9847	9848	9849	9854	9855	9862	9863	9864	9866	9867	9868
9869	9870	9871	9872	9873	9874	9875	9876	9877	9878	9879	9880
9881	9882	9883	9884	9885	9886	9887	9888	9889	9890	9891	9892
9893	9894	9895	9896	9897	9898	9899	9900	9901	9902	9903	9904
9907	9909	9919	9920	9921	9931	9932	9933	9934	9939	9940	9941
9942	9943	9944	9946	9947	9951	9953	9958	9959	9962	10099	10100
10104	10106	10109	10106	10114	10115	10116	10117	10118	10119	10120	10121
10122	10125	10126	10128	10182	10610	11703	11728	12072	12816	16502	19521
19556											
										Total:	644

Three thousand and fifty (3,050) letters were received in support of the proposed rule that were not matched to any mass mail efforts.

Table 9A-21. General Support Letters

3374	3385	3393	3740	4031	4048	4139	4294	4341	4432	4483	4487
4488	4522	4721	4751	4797	4921	5559	6138	7497	7498	7584	7585
7653	7654	7655	7661	7975	8684	9118	9541	9549	9569	9717	9743
10166	10169	10170	10521	10522	10637	10660	10729	10732	10734	10757	10762
10902	10906	11096	11104	11105	11106	11373	11374	11382	11393	11396	11401
11426	11477	11528	11529	11530	11531	11534	11535	11596	11597	11598	11599
11600	11601	11602	11603	11605	11606	11607	11608	11609	11610	11611	11612
11613	11614	11615	11616	11617	11618	11619	11620	11622	11623	11624	11626
11627	11628	11630	11633	11634	11635	11636	11644	11645	11647	11648	11653
11654	11655	11656	11667	11669	11670	11671	11672	11673	11674	11675	11676
11677	11678	11679	11680	11681	11682	11683	11684	11685	11686	11687	11688
11689	11690	11691	11692	11693	11694	11695	11706	11707	11708	11710	11767
11768	11769	11770	11769	11782	11783	11792	11801	11802	11803	11804	11805
11806	11807	11808	11809	11844	11846	11847	11848	11849	11850	11851	11852
11853	11854	11855	11856	11857	11862	11863	11868	11869	11870	11871	11872
11873	11874	11876	11879	11881	11883	11893	11896	11897	11898	11899	11900
11906	11907	11908	11909	11910	11911	11912	11913	11918	11919	11920	11921
11922	11923	11930	11931	11932	11940	11941	11942	11943	11944	11945	11946
11947	11948	11949	11951	11952	11953	11954	11955	11969	11970	11971	11972
11973	11974	11975	11976	11977	11978	11979	11980	11981	11982	11983	11984
11985	11986	11987	11988	11989	11990	11991	11992	11993	11994	12003	12007
12008	12009	12011	12012	12013	12014	12022	12024	12025	12026	12027	12028
12029	12030	12031	12032	12033	12035	12036	12037	12038	12039	12040	12041
12042	12043	12045	12046	12047	12048	12051	12053	12054	12059	12060	12061
12062	12067	12073	12083	12084	12085	12086	12087	12091	12095	12099	12104
12128	12131	12133	12148	12155	12156	12221	12222	12223	12224	12226	12227
12228	12230	12231	12232	12238	12252	12253	12254	12255	12256	12257	12258
12259	12260	12261	12262	12264	12265	12278	12281	12283	12288	12290	12295
12296	12297	12307	12312	12314	12316	12334	12335	12336	12339	12345	12369
12374	12375	12376	12377	12378	12379	12381	12382	12383	12402	12405	12459
12460	12461	12503	12504	12505	12506	12509	12510	12511	12513	12518	12520
12525	12526	12532	12533	12534	12535	12536	12546	12547	12548	12560	12561
12562	12563	12564	12565	12566	12567	12568	12569	12570	12571	12572	12617
12618	12619	12620	12621	12622	12626	12627	12628	12629	12648	12649	12651
12652	12653	12661	12662	12663	12664	12665	12673	12682	12683	12684	12685
12686	12687	12704	12705	12706	12707	12709	12710	12711	12722	12723	12724
12725	12755	12756	12757	12758	12759	12760	12761	12762	12763	12764	12765
12766	12767	12780	12793	12794	12795	12796	12797	12799	12800	12807	12814
12881	12886	12887	12888	12896	12948	12949	12950	12951	12952	12953	12954
12955	12956	12957	12958	12959	12960	12961	12962	12963	12964	12965	12966
12967	12968	12969	12970	12971	12976	12977	12987	12988	12989	12992	12994
12995	13005	13006	13007	13008	13010	13110	13112	13117	13118	13119	13120

13121	13122	13126	13127	13128	13131	13132	13133	13134	13137	13138	13139
13140	13141	13151	13152	13153	13154	13159	13163	13164	13165	13166	13167
13168	13169	13170	13171	13172	13179	13180	13181	13182	13183	13184	13185
13186	13187	13188	13189	13195	13196	13197	13198	13199	13200	13201	13202
13203	13204	13205	13206	13207	13208	13209	13210	13211	13212	13213	13214
13215	13216	13217	13218	13226	13227	13228	13229	13230	13234	13235	13236
13237	13238	13239	13240	13241	13242	13243	13244	13250	13251	13252	13253
13257	13258	13259	13258	13268	13269	13270	13271	13276	13302	13303	13304
13305	13306	13307	13308	13309	13310	13311	13312	13313	13314	13325	13398
13399	13402	13419	13420	13432	13433	13434	13448	13449	13450	13451	13452
13453	13454	13455	13456	13457	13460	13461	13462	13463	13466	13469	13472
13478	13479	13480	13495	13498	13512	13513	13514	13515	13518	13519	13520
13521	13522	13523	13524	13525	13527	13528	13530	13531	13532	13533	13534
13544	13545	13546	13548	13549	13550	13551	13552	13553	13554	13556	13557
13558	13559	13560	13561	13562	13589	13590	13591	13592	13593	13594	13595
13596	13597	13598	13599	13619	13620	13645	13646	13647	13648	13649	13650
13651	13652	13653	13654	13655	13656	13657	13658	13659	13660	13661	13663
13664	13665	13666	13667	13668	13669	13670	13671	13675	13676	13677	13678
13679	13680	13681	13682	13683	13684	13685	13686	13687	13688	13702	13703
13704	13705	13706	13708	13711	13713	13714	13715	13717	13718	13719	13720
13721	13722	13723	13724	13725	13726	13727	13728	13729	13730	13731	13732
13734	13735	13736	13737	13738	13739	13740	13741	13742	13743	13744	13745
13746	13747	13748	13750	13751	13752	13753	13754	13755	13756	13757	13758
13759	13760	13761	13762	13763	13764	13765	13766	13776	13785	13793	13794
13802	13804	13805	13806	13807	13808	13809	13817	13818	13819	13820	13821
13822	13823	13824	13825	13826	13828	13829	13830	13831	13832	13833	13834
13835	13836	13837	13838	13839	13840	13841	13842	13843	13844	13845	13846
13847	13848	13849	13850	13851	13852	13853	13854	13855	13856	13857	13858
13859	13860	13872	13907	13908	13919	13932	13965	13966	13967	13968	13969
13970	13971	13972	13973	13974	13975	13976	13977	13978	13979	13980	13981
13982	14004	14005	14006	14007	14008	14009	14010	14011	14012	14013	14014
14015	14020	14044	14045	14050	14065	14066	14072	14073	14075	14076	14085
14086	14087	14091	14092	14093	14094	14095	14096	14100	14101	14102	14109
14110	14116	14117	14118	14119	14126	14127	14128	14129	14130	14133	14134
14138	14141	14142	14145	14146	14148	14152	14164	14165	14166	14168	14178
14179	14192	14193	14194	14195	14201	14205	14255	14256	14257	14280	14281
14282	14283	14284	14286	14287	14299	14300	14369	14370	14371	14372	14373
14374	14375	14413	14414	14417	14418	14419	14420	14428	14431	14432	14433
14434	14441	14442	14443	14444	14445	14446	14447	14448	14450	14478	14480
14482	14483	14484	14485	14488	14489	14490	14491	14492	14493	14494	14495
14496	14497	14498	14499	14500	14503	14504	14512	14513	14514	14541	14542
14543	14544	14545	14546	14547	14548	14549	14550	14551	14552	14553	14554
14555	14556	14557	14558	14559	14560	14561	14562	14563	14564	14565	14566
14567	14568	14569	14570	14571	14572	14573	14574	14575	14576	14577	14578

14579	14580	14581	14580	14583	14584	14585	14586	14587	14588	14589	14590
14591	14592	14593	14594	14595	14596	14597	14598	14599	14629	14672	14673
14674	14675	14697	14698	14699	14700	14701	14702	14703	14704	14705	14706
14707	14708	14709	14710	14711	14712	14713	14714	14715	14716	14717	14718
14719	14720	14722	14723	14724	14728	14729	14730	14731	14732	14733	14734
14735	14736	14737	14738	14739	14740	14741	14742	14743	14744	14745	14746
14747	14748	14749	14750	14751	14752	14753	14754	14755	14756	14757	14758
14759	14760	14761	14769	14770	14771	14772	14773	14774	14775	14780	14781
14782	14783	14784	14785	14786	14787	14788	14789	14790	14802	14803	14807
14808	14809	14813	14814	14815	14816	14817	14819	14820	14821	14822	14823
14824	14825	14826	14827	14828	14829	14830	14831	14832	14845	14855	14856
14857	14858	14859	14860	14861	14862	14863	14864	14865	14866	14867	14868
14869	14870	14871	14872	14873	14874	14875	14876	14877	14878	14879	14880
14881	14882	14883	14884	14885	14886	14887	14888	14889	14890	14891	14892
14893	14894	14895	14896	14897	14898	14899	14900	14905	14906	14907	14908
14909	14910	14911	14912	14913	14914	14915	14916	14917	14918	14919	14920
14921	14922	14923	14924	14925	14926	14927	14928	14929	14930	14931	14932
14933	14934	14935	14936	14937	14938	14939	14940	14941	14942	14943	14944
14945	14946	14947	14948	14949	14954	14955	14956	14957	14958	14959	14960
14961	14967	14968	14971	14976	14977	14978	14979	14980	14981	14982	14983
14984	14985	14986	14987	14988	14989	14990	14991	14992	14993	14994	14995
14996	14997	14998	14999	15000	15001	15004	15005	15010	15012	15013	15014
15025	15026	15027	15028	15029	15030	15031	15032	15033	15034	15035	15036
15037	15038	15039	15040	15041	15047	15055	15062	15063	15064	15065	15066
15067	15068	15069	15070	15071	15072	15073	15074	15075	15076	15077	15078
15079	15083	15084	15085	15086	15087	15088	15089	15090	15091	15092	15093
15094	15095	15096	15097	15098	15099	15100	15101	15102	15103	15105	15106
15107	15108	15109	15110	15111	15112	15113	15114	15115	15116	15117	15118
15119	15120	15121	15122	15123	15124	15125	15126	15127	15128	15129	15130
15131	15132	15133	15134	15135	15136	15137	15138	15139	15140	15141	15142
15143	15144	15145	15146	15147	15148	15149	15150	15151	15152	15153	15154
15155	15156	15157	15158	15159	15162	15163	15169	15175	15177	15178	15179
15181	15183	15184	15185	15186	15187	15188	15189	15191	15192	15193	15199
15200	15201	15202	15203	15204	15205	15206	15207	15208	15213	15215	15216
15218	15222	15223	15226	15228	15231	15232	15233	15234	15235	15236	15237
15238	15239	15240	15241	15242	15243	15245	15246	15247	15248	15254	15255
15256	15257	15258	15259	15260	15261	15262	15263	15266	15269	15270	15271
15272	15276	15284	15276	15288	15300	15301	15302	15303	15304	15305	15306
15307	15308	15309	15310	15311	15312	15313	15314	15315	15316	15317	15318
15319	15328	15329	15330	15331	15336	15352	15353	15354	15355	15356	15357
15358	15359	15360	15361	15362	15363	15364	15365	15366	15367	15368	15369
15370	15371	15372	15373	15374	15375	15376	15377	15378	15379	15380	15381
15382	15383	15384	15385	15392	15393	15394	15395	15396	15397	15398	15404
15410	15411	15412	15413	15414	15415	15416	15417	15418	15424	15426	15427

15428	15429	15430	15431	15432	15447	15451	15452	15453	15454	15455	15456
15459	15462	15463	15464	15466	15467	15468	15469	15470	15471	15472	15473
15474	15475	15476	15477	15478	15479	15480	15481	15482	15493	15497	15499
15500	15501	15502	15503	15504	15505	15506	15507	15508	15509	15510	15511
15512	15513	15521	15524	15535	15537	15538	15539	15540	15541	15542	15543
15544	15545	15546	15547	15554	15555	15561	15562	15563	15564	15565	15571
15572	15573	15574	15575	15576	15577	15578	15579	15580	15581	15582	15583
15584	15585	15586	15587	15588	15589	15591	15592	15593	15594	15595	15596
15597	15598	15599	15600	15601	15602	15603	15604	15605	15606	15607	15608
15609	15610	15611	15612	15613	15614	15615	15616	15617	15618	15619	15620
15621	15622	15623	15624	15625	15626	15627	15628	15629	15630	15631	15632
15633	15634	15635	15637	15638	15639	15640	15641	15642	15643	15644	15645
15646	15647	15648	15649	15650	15651	15652	15653	15654	15655	15656	15657
15658	15659	15660	15665	15666	15667	15679	15692	15693	15694	15695	15696
15697	15698	15699	15700	15701	15702	15703	15704	15705	15706	15707	15708
15709	15710	15711	15712	15713	15714	15715	15716	15717	15718	15719	15720
15721	15722	15723	15724	15725	15726	15727	15728	15729	15730	15731	15732
15733	15734	15735	15736	15737	15738	15739	15740	15741	15742	15743	15744
15745	15746	15747	15748	15749	15750	15751	15752	15753	15754	15755	15756
15757	15758	15759	15760	15761	15762	15763	15764	15765	15766	15767	15800
15801	15804	15805	15806	15807	15808	15809	15810	15811	15814	15815	15816
15817	15818	15819	15820	15821	15822	15830	15832	15833	15834	15835	15836
15837	15838	15839	15840	15841	15842	15843	15844	15845	15846	15847	15848
15849	15853	15854	15855	15856	15857	15858	15859	15860	15861	15862	15863
15864	15874	15877	15878	15879	15881	15885	15886	15887	15888	15889	15890
15897	15898	15899	15900	15901	15902	15903	15904	15905	15906	15907	15908
15909	15916	15927	15928	15929	15936	15937	15938	15939	15940	15941	15942
15943	15944	15945	15946	15947	15957	15962	15963	15964	15965	15966	15967
15968	15969	15970	15971	15972	15973	15974	15975	15976	15977	15978	15979
15980	15981	15982	15983	15986	15987	15988	15989	15990	15991	15992	15993
15994	15995	15996	15995	15998	16002	16003	16004	16015	16016	16017	16018
16019	16020	16021	16022	16023	16033	16034	16035	16036	16037	16038	16039
16040	16041	16042	16043	16044	16045	16048	16050	16051	16056	16057	16058
16059	16061	16062	16063	16070	16071	16074	16076	16077	16078	16079	16082
16085	16086	16087	16088	16089	16090	16091	16093	16103	16105	16106	16107
16108	16109	16110	16111	16112	16113	16118	16119	16120	16123	16124	16137
16138	16139	16140	16141	16142	16143	16144	16145	16146	16149	16152	16163
16167	16168	16169	16170	16171	16172	16173	16174	16175	16176	16178	16179
16180	16181	16182	16183	16184	16185	16186	16187	16188	16189	16191	16193
16194	16195	16196	16197	16198	16199	16200	16201	16202	16203	16204	16205
16206	16219	16232	16240	16243	16244	16245	16246	16247	16248	16249	16250
16251	16252	16253	16254	16255	16256	16257	16258	16259	16260	16261	16262
16263	16264	16265	16266	16267	16268	16269	16270	16271	16272	16273	16274
16275	16276	16277	16278	16279	16280	16284	16288	16289	16290	16291	16292

16293	16294	16295	16296	16301	16302	16305	16307	16308	16309	16310	16313
16317	16318	16321	16325	16326	16327	16328	16329	16330	16331	16332	16333
16334	16335	16336	16337	16338	16339	16340	16341	16342	16343	16344	16347
16348	16356	16359	16360	16361	16362	16363	16364	16365	16366	16367	16368
16369	16370	16371	16372	16373	16374	16375	16385	16407	16408	16409	16410
16411	16419	16420	16421	16422	16423	16424	16425	16426	16427	16428	16429
16430	16431	16432	16433	16434	16437	16487	16490	16491	16492	16493	16494
16495	16496	16497	16498	16499	16503	16519	16544	16563	16570	16571	16572
16573	16574	16579	16580	16582	16583	16593	16594	16595	16596	16599	16600
16601	16604	16605	16606	16607	16608	16609	16610	16611	16612	16613	16614
16615	16616	16617	16618	16619	16620	16621	16622	16623	16624	16625	16631
15745	15746	15747	15748	15749	15750	15751	15752	15753	15754	15755	15756
15757	15758	15759	15760	15761	15762	15763	15764	15765	15766	15767	15800
15801	15804	15805	15806	15807	15808	15809	15810	15811	15814	15815	15816
15817	15818	15819	15820	15821	15822	15830	15832	15833	15834	15835	15836
15837	15838	15839	15840	15841	15842	15843	15844	15845	15846	15847	15848
15849	15853	15854	15855	15856	15857	15858	15859	15860	15861	15862	15863
15864	15874	15877	15878	15879	15881	15885	15886	15887	15888	15889	15890
15897	15898	15899	15900	15901	15902	15903	15904	15905	15906	15907	15908
15909	15916	15927	15928	15929	15936	15937	15938	15939	15940	15941	15942
15943	15944	15945	15946	15947	15957	15962	15963	15964	15965	15966	15967
15968	15969	15970	15971	15972	15973	15974	15975	15976	15977	15978	15979
15980	15981	15982	15983	15986	15987	15988	15989	15990	15991	15992	15993
15994	15995	15996	15995	15998	16002	16003	16004	16015	16016	16017	16018
16019	16020	16021	16022	16023	16033	16034	16035	16036	16037	16038	16039
16040	16041	16042	16043	16044	16045	16048	16050	16051	16056	16057	16058
16059	16061	16062	16063	16070	16071	16074	16076	16077	16078	16079	16082
16085	16086	16087	16088	16089	16090	16091	16093	16103	16105	16106	16107
16108	16109	16110	16111	16112	16113	16118	16119	16120	16123	16124	16137
16138	16139	16140	16141	16142	16143	16144	16145	16146	16149	16152	16163
16167	16168	16169	16170	16171	16172	16173	16174	16175	16176	16178	16179
16180	16181	16182	16183	16184	16185	16186	16187	16188	16189	16191	16193
16194	16195	16196	16197	16198	16199	16200	16201	16202	16203	16204	16205
16206	16219	16232	16240	16243	16244	16245	16246	16247	16248	16249	16250
16251	16252	16253	16254	16255	16256	16257	16258	16259	16260	16261	16262
16263	16264	16265	16266	16267	16268	16269	16270	16271	16272	16273	16274
16275	16276	16277	16278	16279	16280	16284	16288	16289	16290	16291	16292
16293	16294	16295	16296	16301	16302	16305	16307	16308	16309	16310	16313
16317	16318	16321	16325	16326	16327	16328	16329	16330	16331	16332	16333
16334	16335	16336	16337	16338	16339	16340	16341	16342	16343	16344	16347
16348	16356	16359	16360	16361	16362	16363	16364	16365	16366	16367	16368
16369	16370	16371	16372	16373	16374	16375	16385	16407	16408	16409	16410
16411	16419	16420	16421	16422	16423	16424	16425	16426	16427	16428	16429
16430	16431	16432	16433	16434	16437	16487	16490	16491	16492	16493	16494

16495	16496	16497	16498	16499	16503	16519	16544	16563	16570	16571	16572
16573	16574	16579	16580	16582	16583	16593	16594	16595	16596	16599	16600
16601	16604	16605	16606	16607	16608	16609	16610	16611	16612	16613	16614
16615	16616	16617	16618	16619	16620	16621	16622	16623	16624	16625	16631
17172	17173	17175	17176	17177	17178	17179	17180	17181	17182	17183	17185
17186	17187	17188	17189	17190	17192	17195	17196	17198	17199	17200	17201
17202	17203	17204	17205	17206	17207	17208	17209	17210	17211	17212	17213
17214	17215	17216	17217	17218	17219	17220	17221	17222	17223	17224	17225
17226	17227	17228	17237	17238	17241	17242	17243	17244	17246	17247	17248
17249	17250	17251	17255	17267	17268	17271	17273	17274	17275	17276	17277
17282	17289	17290	17292	17293	17303	17304	17309	17310	17317	17318	17319
17320	17321	17323	17336	17337	17338	17339	17340	17341	17342	17343	17344
17345	17346	17347	17348	17349	17350	17351	17352	17353	17355	17356	17357
17358	17359	17360	17361	17362	17363	17364	17366	17367	17368	17369	17371
17372	17373	17375	17376	17377	17378	17379	17380	17382	17384	17387	17388
17389	17390	17391	17393	17395	17396	17397	17398	17399	17407	17457	17463
17465	17466	17470	17466	17473	17489	17490	17496	17624	17641	17652	17688
17759	17764	17780	17793	17828	17832	17888	17896	17905	17906	17907	17932
17933	17934	17935	17951	17952	18040	18041	18042	18044	18045	18046	18047
18048	18049	18065	18249	18260	18267	18286	18287	18288	18302	18306	18313
18319	18361	18362	18363	18364	18365	18366	18367	18368	18369	18370	18401
18406	18413	18503	18504	18505	18506	18507	18511	18547	18548	18551	18552
18554	18557	18616	18646	18668	18669	18670	18671	18672	18695	18696	18697
18708	18712	18719	18743	18828	18850	18869	18878	18879	18918	18928	18929
18957	18972	18973	18974	18987	19004	19009	19010	19013	19016	19024	19027
19028	19030	19039	19084	19089	19090	19095	19097	19098	19099	19102	19103
19117	19118	19119	19124	19144	19149	19154	19155	19156	19159	19161	19162
19164	19165	19166	19167	19172	19173	19175	19177	19179	19195	19196	19198
19202	19206	19220	19221	19223	19224	19226	19227	19228	19229	19236	19238
19239	19240	19241	19242	19244	19246	19247	19248	19249	19255	19256	19257
19258	19259	19260	19262	19264	19265	19271	19273	19274	19275	19276	19277
19278	19279	19280	19281	19282	19283	19284	19285	19286	19287	19290	19293
19294	19300	19301	19308	19309	19328	19330	19331	19332	19433	19507	19518
19519	19529	19531	19554	19561	19575	19576	19577	19582	19590	19591	19594
19596	19597	19598	19599	19600	19602	19604	19605	19607	19614	19616	19618
19619	19621	19623	19624	19626	19655	19656	19657	19658	19676	19695	19696
19697	19698										
										Total:	3,050

9B - General Opposition

Comment 1: The EPA received 4,830 mass-mail and form letters expressing general opposition to the electric generating units NESHAP. Commenter's concerns include the rule's effect on electricity prices, system dependability, employment, and the effect on small businesses and the overall economy. Due to the high number of comments for this proposed rule, these comments were categorized and sorted according to the group that organized the mass-mail campaign.

The U.S. Docket office identified 4,527 mass-mail comment letters and assigned them to 6 DCNs, simplifying this process. These mass-mail DCNs are listed in Table 9B-1 of this section with the count of comment letters and the associated organization.

More mass-mail comment letters were identified from the remaining comment letters and are listed in Tables 9B-2 through 9B-4 in this section.

Letters expressing general opposition that are not associated with any mass-mail campaign are listed in Table 9B-5 in this section.

Many organizations provided members with form letters. Form letters containing substantive comments had a few representative letters excerpted and summarized for the Response to Comments document. The remaining letters are listed here.

Many commenters (17295, 17401, 17748, 17749, 17750, 17763, 17778, 17783, 17788, 17792, 17822, 17825, 17826, 17827, 17866, 17890, 17891, 17897, 17910, 17924, 18414, 18482, 18499, 18705, 18706, 18894, 18936, 18937, 18944, 19549, 19559, 19560, 19566) representing municipal utilities expressed concerns about the proposed rule. These commenters asked that the EPA evaluate the impact of the proposed rule under SBREFA, UMRA and EO 13563, EO 13132, EO 12866, and EO 13211. Comments are discussed in further detail by commenter 18038.

Response to Comment 1: The EPA acknowledges the general concerns of the commenters regarding the Mercury and Air Toxics Standards, and responses to comments elsewhere in this document generally address those concerns. Comments and responses relating to the consideration of SBREFA, UMRA, EO 13563, EO 13132, EO 12866, and EO 13211 may also be found elsewhere in this document.

Section 9B Tables

Mass Mailings - General Opposition to the Proposed Rule

Table 9B-1. Mass mail comments identified by the U.S. Docket Office

DCN	Docket Entry	Count
19651	Mass Comment Campaign sponsoring organization unknown	142
19633	Mass Comment Campaign sponsoring organization unknown	885
19646	Mass Comment Campaign sponsoring organization unknown	20
19645	Mass Comment Campaign sponsoring organization unknown	945
19650	Mass Comment Campaign sponsoring organization unknown	1,788
19652	Mass Comment Campaign sponsoring organization unknown	747
	Total:	4,527

In addition to the mass mailings identified by the U.S. Docket Office, 268 mass mail comments were also identified by RTI International.

Table 9B-2. American Electric Power

14487	14509	14511	14520	14610	14612	14613	14614	14616	14617	14618	14619
14620	14621	14624	14628	14630	14631	14634	14635	14636	14637	14638	14639
14640	14641	14642	14643	14644	14645	14646	14647	14649	14651	14652	14654
14656	14658	14659	14660	14662	14664	14666	14667	14668	14671	14679	14680
14681	14682	14683	14684	14685	14686	14687	14688	14689	14690	14691	14692
14693	14694	15190	15439	15560	15566	15567	15568	15569	15661	15662	15663
15664	15670	15768	15769	15770	15771	15772	15773	15779	15780	15781	15782
15783	15785	15793	15794	15795	15796	15797	15798	15799	15812	15825	15826
15827	15829	15850	15851	15868	15869	15870	15871	15872	15880	15882	15924
15925	15935	15948	15950	15958	16127	16130	16154	16159	16160	16161	16162
16208	16212	16221	16222	16223	16224	16234	16239	16285	16286	16287	16300
16314	16315	16316	16324	16349	16350	16351	16353	16354	16355	16357	16358
16376	16379	16381	16379	16436	16450	16461	16488	16489	16501	16517	16536
16537	16542	16597	16845	17108	17184	17300	17330	17331	17332	17333	17334
17335	17354	17365	17370	17445	17472	17486	17908	17947	17953	18186	18301
18357	18377	18558	18565	18571	18620	18621	18623	18631	18661	18662	18664
18682	18683	18686	18689	18690	18692	18693	18694	18699	18776	18780	18784
18841	18849	18874	18917	18925	18926	18927	18940	18955	18969	18971	19085
19295	19320	19625									
										Total:	219

Table 9B-3. Chamber of Commerce

17657	17658	17659	17660	17661	17680	17684	17685	17686	17693	17694	17695
17700	17708	17717	17779	17823	18415	18416	18417	18418	18420	19296	
										Total:	23

Table 9B-4. Public Service Company of Oklahoma

18959	18960	18975	19025	19026	19029	19091	19096	19100	19109	19140	19141
19142	19148	19153	19158	19160	19163	19168	19174	19176	19261	19266	19461
19527	19584										
										Total:	26

The EPA received 35 letters opposing the proposed rule that were not matched to any mass mail efforts.

Table 9B-5. General Opposition Letters

12152	12192	12708	13749	14003	14427	14501	14519	14625	14818	15104	16412
16414	16415	16416	16417	16438	16543	16718	16947	16966	17032	17233	17269
17280	17329	18279	18615	18622	18867	18966	19178	19302	19562	19635	
										Total:	35

CHAPTER 10: INCORPORATION BY REFERENCE

10 - Incorporation by Reference

Comment: Many commenters requested that the remarks of other commenters be incorporated into their own comments on the proposed rule. The table below lists the commenters who have been referenced, followed by the commenters who asked to incorporate the referenced commenters' remarks. Specifically, the first column in Table 10-1 is a list of commenters who were referred to by other commenters. The second column gives a short name for the commenters who were referenced. The third column provides a list of the commenters who referred to each of the referenced commenters.

Response: The EPA acknowledges the general concerns of the commenters regarding the proposed Mercury and Air Toxics Standards and has responded to them in this document, the preamble to the final rule, and other associated technical and regulatory impact analysis supporting materials.

Table 10-1. Incorporation by Reference

Referenced Commenter DCN	Referenced Commenter Short Name	Referencing Commenters
17799	ACCCE	17790
17877	AECI	19094
17815	AECT	17904, 18785
19114	AEP	17715, 17757, 18907, 19041
17810	ANGA	17853
8443, 17868	APPA	17655, 17702, 17705, 17767, 18015, 18018, 18031, 18032, 18437, 18500, 18831, 19121, 19213
17754	ARIPPA	18427
17757	Buckeye	19041
17760	Class 85	17702, 17722, 17776, 17807, 17870[a], 17902, 17909, 17920, 18018, 18020, 18831
17808	Clean Energy Group	17870[a], 18025
18500	CPG	18437
17758	EEI	17627, 17770, 17772, 17776, 17790, 17800, 17805[b], 17807, 17820, 17870[a], 17881, 17902, 17920, 18015, 18031, 18428
18037	EPGA	17627
17621	EPRI	17627, 17705, 17722, 17730, 17757, 17790, 17800, 17820, 17821, 17881, 17886, 17902, 17904, 18015, 18020, 18021, 18428, 18437, 18443, 19041
17638	FCG	17702, 17769, 17807, 17814, 18018, 18831
18018	FMEA	18831
17930	GCLC	17813, 17904, 18785
17698	GPA	17710
19506	IDEM	19212
19122	LADWP	19121
17724	LEC	17722, 17805, 18031

17623	LPPC	17705, 18437, 18831
18426	MDEQ	17881
19742	MMA	17881
18488	MOG	17627, 17800
17297	MPSC	17881
17640, 19580	NAM	18031
17701, 17791	NARUC	16850
17842	ND PSC	17805
17735	New Units	17817
18033	NMA	17901, 17904, 18051, 18424, 18489
17689	NRECA	17197, 17909, 17730, 17757, 17813, 17817, 17909[c], 18020, 18429, 18443, 18820, 19041, 19094
17736	OEUG	17627, 17715, 17772
16549	PACE	17137, 17782
18448, 18441	PJM	17804
16873	PUCO	17856
18538	TX PUC	18034
17775	UARG	17197, 17627, 17705, 17715, 17728, 17730, 17737, 17770, 17772, 17790, 17795, 17800, 17820, 17821, 17868[d], 17881, 17886, 17904, 18015, 18021, 18031, 18033, 18428, 18429, 19041, 19121, 18203
16496	UJAE	17817
17656	WBRT	17805
19741	West	17705, 17737, 18015
14115	Willie Soon	14368

[a] NextEra Energy Inc. (DCN 17870) incorporated by reference comments from several contributors, but with the caveat, "except in instances when the comments of these industry groups may conflict with NextEra Energy's position as set forth in the comments below."
[b] Montana-Dakota Utilities Company (DCN 17805) incorporated by reference the majority of EEI's comments, as identified in Montana-Dakota Utilities Company's letter.
[c] PowerSouth Energy Cooperative (DCN 17909) incorporated by reference comments from NRECA on setting numerical standards.
[d] American Public Power Association (DCN 17868) incorporated by reference UARG's comments in regard to data availability, data analysis, conversion errors, and MACT monitoring.

APPENDIX A: PUBLIC HEARING PARTICIPANTS

List of Speakers for Public Hearing – Atlanta – 26 May 2011

Time	Name	Affiliation
9:15	Josh Galperin	Southern Alliance for Clean Energy
9:20	Jen Rennicks	Southern Alliance for Clean Energy
9:25	Katie Preston	Georgia Interfaith Power and Light
9:30	Colleen Kiernan	Georgia Sierra Club
9:35	Peter Bahouth	US Climate Action Network
9:40	H. James Gooden	American Lung Association Board of Directors
9:45	Robert Kappelmann	Energy and Environmental Policy Consultants
9:50	Dr. Anne Mellinger-Birdsong	Georgia Chapter of the American Academy of Pediatrics Committee on Environmental Health
9:55	Janice Nolen	American Lung Association
10:00	Charles “Clay” B. Jones, III	Georgia Traditional Manufacturers Association
10:05	William P. Brown	Individual
10:10	Representative Scott Holcomb	GA State Representative
10:15	Dale Kemmerick	POPE
10:20	Stanley P. Saunders	Individual
10:25	Juliet Cohen	Upper Chattahoochee River Keeper
10:30	Rebecca Watts-Hull	Mothers & Others for Clean Air
10:35	Joe Hudson	Farmers & Merchants Bank
10:40	Chris Hobson	Southern Company Services
10:45	Rev. Woody Bartlett	Georgia Interfaith Power & Light
10:50	Robert D. Bullard	Environmental Justice Resource Center Clark Atlanta University
10:55	Dr. Yolanda Whyte	Individual
11:00	Mike Kennedy	Progress Energy
11:05	Byron T. Burrows	Tampa Electric Company
11:10	Alison Amyx	Georgia Interfaith Power & Light
11:15	Bob Donaghue	Georgia Interfaith Power & Light
11:20	Clark Efaw	Georgia Interfaith Power and Light
11:25	Dr. James Rust	
11:30	Thomas Pearce	Sierra Club
11:35	Robin Mann	Sierra Club
11:40	Jaffer Khimani	Clean Air Task Force
11:45	Mark MacLeod	Environmental Defense Fund
11:50	John B. Hammond	National Wildlife Federation
11:55	Jack Thirolf	Business Council for Sustainable Energy
12:00	Dabney Dixon	Individual
12:05	Lance Brown	Partnership for Affordable Clean Energy (PACE)
12:10	Steve Earle	UMWA Region 3
12:15	Virginia Galloway	Americans for Prosperity
12:20	Kevin McGrath	GA Trout Unlimited
12:25	Alan O. Toney	Individual

Time	Name	Affiliation
12:30	James Capp	Georgia Air Protection Branch
12:35	Joy Kramer	GA Solar Energy Association
12:40	Thelma Heywood	Sierra Club
12:45	Roger Mills	Individual
12:50	Sean Hutchins	KY Environmental Foundation
2:10	Seandra Rawls	Southern Alliance for Clean Energy
2:15	Eriqua Foreman Williams	Southern Alliance for Clean Energy
2:20	Emily Enderlee	Earthjustice
2:25	Danny Schweinhart	Individual
2:30	Alexei Laushkin	The Evangelical Environment Network
2:35	Rev. Richard Cizik	Evangelicals for the Common Good
2:40	Glen Hooks	Sierra Club
2:45	Katherine Helms Cummings	FACE
2:50	Midge Sweet	Georgians for Smart Energy Coalition
2:55	Lynn Redwood	SAFE MINDS
2:25	Jennette Gayer	Environment Georgia
2:55	Dave Muhly	Sierra Club
3:00	Eddie Ehlert	Individual
3:05	Lyndsay Moseley	Sierra Club
3:10	Imran Battla	The Prana Group
3:15	David Richardson	
3:20	Ron Shipman	Georgia Power Company
3:25	Seth Hutchins	KY Environmental Foundation
3:30	Thomas Hutegger	Individual
3:35	John Walsh	Sierra Club
3:40	Robert Fletcher	
3:45	Elizabeth Crowe	Kentucky Environmental Foundation
3:50	Kathy Little	Kentucky Environmental Foundation
3:55	Robert Ukeiley	Citizen
4:00	Natalie Crone & Student group Chelsea Carroll Matt Callo Shawn Hutchins Alex English Austin Delph Seth Hutchins	Kentucky Environmental Foundation
4:05	Simon Montelongo	Kentucky Environmental Foundation
4:10	Benita Dodd	
4:15	Shelia Tyson	Citizen-Birmingham, Al
4:20	Jessica Spruill	Southern Energy Network
4:25	Joan Lindop	Sierra Club GA
4:30	Elizabeth Lopez	Global Warming and Energy Team

Time	Name	Affiliation
4:35	Patti Gettinger	Individual
4:40	Rel Corbin	
4:45	Cassy Hobert	Kentucky Environmental Foundation
4:50	Michael J. Churchman	Alabama Environmental
4:55	Molly Embree	Environment Georgia
5:00	April Ingle	GA River Network
5:05	Natasha Herbert	
5:10	Arthur Gibert	Sierra Club
5:15	Andrea Lyle	Individual
5:20	John Krueger	Georgia Chamber of Commerce 30303
5:25	Flora Tommie	Sierra Club / Perkerson Civic Association (PCA)
5:30	June Deen	American Lung Association in Georgia
6:40	Lev Guter	Sierra Club
6:45	Jenna Garland	Southern Energy Network
6:50	Michael Wall	Environment Georgia
6:55	Bill Cunningham	Unions for Jobs and the Environment (UJAE)
	Mark Woodall	Sierra Club Georgia Chapter
7:10	Tony C. Anderson	The Lets Raise a Million Education Fund
7:15	Erin Glynn (presented video testimony narrated by Erin Savage)	Sierra Club
7:20	John Noel	Individual
7:25	Burt Lesnick	American Thoracic Society
7:35	Brandon Sutton	Sierra Club
7:40	Carly Queen	Individual
7:45	Melissa Nummink	Individual

List of Speakers for Public Hearing – Chicago – 24 May 2011

Time	Name	Affiliation
9:15	Rev. Dr. Clare Butterfield	Faith in Place and the Illinois Interfaith Power and Light Campaign
9:20	Rev. Faith Bugel	Environmental Law and Policy Center
9:25	Brian Urbaszewski	Respiratory Health Association of Metropolitan Chicago
9:30	Amy M. Trojecki	Exelon Business Services Company
9:35	Ben Lowe	Evangelical Environmental Network
9:40	Verena Owen	Sierra Club
9:45	Peter Iwanowicz	American Lung Association
9:50	Sarah Hodgdon	Sierra Club
9:55	Matthew Dunne for Lisa Madigan	IL Attorney General
10:00	Mary Gade	Gade Environmental Group, LLC
10:05	Catie Krasner	Environmental Illinois
10:10	Steve Frenkel	Union of Concerned Scientists
10:15	Jerry Mead-Lucero	Pilsen Environmental Rights and Reform Organization
10:20	William "Bill" Kempiners	American Lung Association Advocacy Committee
10:25	Jennifer Johnson Monberg	Individual
10:30	Lyman C. Welch	Alliance for the Great Lakes
10:35	Erika Dornfeld	Faith in Place
10:40	Michael T.W. Carey	Ohio Coal Association
10:45	Matt Most	Encana Natural Gas Inc.
10:50	Dr. Michael S. Hogue	Meadville Lombard Theological School
10:55	Matthew Soerens	Individual
11:00	Jerome Stone	Individual
11:05	Cathy S. Woollums	MidAmerican Energy Holdings Company
11:10	Dr. Lin Kaatz Chary	Indiana Toxics Action
11:15	Dr. Dawn M. Nothwehr	Catholic Theological Union
11:20	Dr. Helen J. Binns	American Academy of Pediatrics
11:25	Nancy Bultinck	Respiratory Health Association of Metropolitan Chicago
11:30	Jim Ginderske	Neighbors for a Healthy Rogers Park
11:35	Michael Murray	Individual
11:40	Eve Pytel	Metropolitan Mayors Caucus Clean Air Counts Campaign
11:45	Terry Grace	Educator – Retired
11:50	Cory Jones	Sierra Club
11:55	Don Ferber	Sierra Club
12:00	Rev. Homer Cobb	NAACP
12:05	Kimberly Wasserman	Little Village Environmental Justice Organization /NETAC
12:10	Ian Viteri	Little Village Environmental Justice Organization
12:15	Victoria Persky	Individual
12:20	John Blair	Valley Watch
12:25	Leigh Touchton	NAACP
12:30	Dr. Howard Ehrman	UIC/LVESO

Time	Name	Affiliation
12:35	Benjamin Stewart	Lutheran School of Theology at Chicago
12:40	Janet Bohn	Individual
12:45	David Shaw	National Association of Clean Air Agencies
12:50	Brenda Archambo	Individual
2:00	Rose Gomez	Sierra Club
2:05	Chris Pado	Individual
2:10	Dr. Suzanna McColley	American Thoracic Society
2:15	Richard Cogan	President of Textile Industries, Inc.
2:20	Margaret Nelson	League of Conservation Voters
2:25	Shannon Fisk	Natural Resources Defense Council
2:30	Laura Kratz	League of Women Voters of Illinois
2:35	Alfred B.J. Williams II	NAACP
2:40	Brad Vam Guilder	Ecology Center, Ann Arbor, MI
2:45	Susan Michetti	Individual
2:50	Howard A. Learner	Environmental Law and Policy Center
2:55	Boise Jones	Sierra Club/EJAM
3:00	Ade Oba Abdalla	Energy Efficiency and Environmental Health Services - Task Force
3:05	Dennis Nelson	NEIS
3:10	Jerry B. Cain	Judson University
3:15	Rebecca Rossof	Climate and Energy Program
3:20	Michelle Martinez	Sierra Club
3:25	Ingrid Wendland (daughter of Juliee De La Terre)	Individual
3:27	Juliee De La Terre	Individual
3:30	Lance Green	Individual
3:35	Patricia Rosenthal	Sierra Club
3:40	Kelly Pierce	Individual
3:45	Patricia A.S. Crowley	Kalamazoo County Drain Commissioner
3:50	James McPike	Individual
3:55	Vivian Hood	Individual
4:00	Joan Arnold	Individual
4:05	Dr. Sarah Lovinger	Physicians for Social Responsibility
4:10	Susan E. Harley	Michigan Policy Director
4:15	Lee Sprague	Little River Band of Ottawa Indians Tribal Council
4:20	Danielle Korpalski	National Wildlife Federation
4:25	Frank Szollosi	National Wildlife Federation’s Great Lake’s Office in Ann Arbor
4:30	Suhail Barot	Individual
4:35	Amy Allen	Individual
4:40	Dr. Barbara Timmermans	Evangelical Environmental Network
4:45	Frederick Ellsworth	Sierra Club
4:50	Dr. Daniel N. Weber	Children’s Environmental Health Sciences Center

Time	Name	Affiliation
4:55	Amanda Kaley	Individual
5:00	Susan Williams	Sierra Club
5:05	David A. Creech	ELCA World Hunger
5:10	Dr. Edward (Ted) Naureckas	Individual
5:15	Sue Blaine	Labadie Environmental Organization/Individual
5:20	Dana March	Individual
5:25	Jason Duba	Individual
5:30	Jennifer Jansen	National Wildlife Federation
5:35	Jocelyn Travis	NAACP
5:40	David L. DePrez	Individual
5:45	Rose Joshua	NAACP
5:50	Auriel Banister	Little Village Environmental Justice Organization
6:45	Olivia Woollam	University of Chicago Climate Action Network, and the Chicago Youth Climate Coalition
6:50	Caroline Wooten	UChicago Climate Action Network, Chicago Youth Climate Coalition
6:55	Pamela Ortner	Individual
7:00	Donna Hriljac	Individual
7:05	Rev. Theresa Dear	NAACP
7:10	Jim Schneider	Individual
7:15	Dr. Sam Dorevitch	University of Illinois
7:20	Susanne Brooks	Environmental Defense Fund
7:25	Brian Perbix	Sierra Club
7:30	Sherry Leonard	Individual
7:35	Marianne Flanagan	Individual
7:40	Jessica Brackett	Individual
7:45	Paul Kim	University of Chicago
7:50	Joyce Blumenshine	Heart of Illinois Sierra Club
7:55	Dr. Maureen McCue	Iowa Physicians for Social Responsibility
8:00	Susan Lannin	Individual
8:05	Tim Sutherlin	Individual
8:10	Kristen Vyhnal	Individual
8:15	Melissa Mullarkey	
8:20	Alexandra Sipiora	Individual
8:25	Kevin Carol	Individual
8:30	Adam Burke	Individual
8:35	Marybeth Gardam	Women's International League for Peace & Freedom
8:40	Richard Stucky	Individual
8:45	Grace Pai	University of Chicago
8:50	Dr. Robert A. Rosenstein	Sierra Club, Union of Concerned Scientists, and Green America
8:55	Carol Chaplan	GREENFAITH
9:00	Chris Didato	Individual
9:05	Bonnie Atkins	Clean Air Muscatine

List of Speakers for Public Hearing – Philadelphia – 24 May 2011

Time	Name	Affiliation
9:15	Rabbi Daniel Swartz	Scranton Area Ministerium and PA Interfaith Power and Light
9:20	Deborah P. Brown	The American Lung Assoc.
9:25	Charles McPhedran	Citizens for PA's Future (PennFuture)
9:30	Robin Mann	Sierra Club
9:35	Joseph Minott	Clean Air Council
9:40	Adam Garber	Penn Environment
9:45	Paul J. Miller	Northeast States for Coordinated Air Use Management
9:50	Dr. Walter Tsou	Philadelphia Physicians for Social Responsibility
9:55	Stephen Harvey	Sierra Club; Pepper Hamilton LLP
10:00	Reverend Cheryl Pyrch	Summit Presbyterian Church
10:05	Eileen O'Boyle	Greenpeace USA
10:10	Jay Butera	Individual
10:15	Rev. Mitchell Hescox	Evangelical Environmental Network
10:20	Leslie G. Fields	Sierra Club
10:25	Paul G. Billings	American Lung Association
10:30	James W. Banford, Jr.	International Brotherhood of Boilermakers; Boilermakers Local Lodge No. 13
10:35	Dr. Poune Sabieri	Sierra Club
10:40	Doug Keith	Sierra Club
10:45	Joy Bergey	The Center for the Celebration of Creation
10:50	Kevin M. Stewart	American Lung Association of the Mid-Atlantic
10:55	Christine Guhl	Sierra Club
	Statement from Anna Maria Caldera read by Christine Guhl	Individual
11:00	Scott Segal	Electric Reliability Coordinating Council/B&G
11:05	Corinne Wright	Sisters of St. Francis of Philadelphia
11:10	Thomas Au	Clean Air Board of Central Pennsylvania
11:05	Ed Perry	National Wildlife Federation
11:10	Don Robertson	Isaac Walton League of America
11:15	Rev. Horace W. Strand	Chester Environmental Partnership
11:20	William Kramer	Sierra Club
11:25	Dr. Scott Manaker	American Thoracic Society
11:30	Chris Salmi	New Jersey Department of Environmental Protection
11:35	Michael Bradley	The Clean Energy Group
11:40	Anthony DiSorbo	Individual
11:45	John McLaughlin	Individual
11:50	Jack Miller	Individual
11:45	Mariko Franz	Individual
11:50	Paul J Mellon, Jr	Novetas Solutions, LLC
11:55	Jim Black	Partnership for Sustainability in Delaware
12:00	Kevin Pflug	Sierra Club
12:05	Mervyn Kline	Individual

Time	Name	Affiliation
12:10	Alicia McDevitt	MA Dept of Environmental Protection
12:15	Margaret Motheral	Union of Concerned Scientists
12:20	Catherine Bowes	National Wildlife Federation
12:25	Rabbi Kevin M. Kleinman	Individual
12:30	Jamin Bogi	Group Against Smog and Pollution
2:15	Nancy Parks	SC/PA Chapter/Clean Air Committee
2:20	Jay Butera	One Million Calls For Clean Energy
2:25	Katie Feeney	Clean Air Council
2:30	Tyra Bryant-Stephens	The Community Asthma Prevention Program
2:35	Candance Cheatham	Individual
2:40	Mark Schmerling	Individual
2:45	Dr. Rima Synnestivedt	Sierra Club
2:50	Robert Cooper	Union of Concerned Scientists
2:55	Sarah Bucic	Delaware City Environmental Coalition
3:00	Dr. Kristen Welker-Hood	Physicians for Social Responsibility
3:05	Gretchen Dahlkemper-Alfonso	Individual
3:10	Judith Focareta	
3:15	Sarah Landini	Pittsburgh City Council
3:20	John Elwood	Evangelical Environmental Network
3:25	Rev. Leah Schade	The Evangelical Lutheran Church in America
3:30	Donna Henry	Individual
3:35	Dr. Kevin Osterhoudt	American Academy of Pediatrics
3:40	Theodore Carrington	NAACP
3:45	Gina E. Wood	Joint Center for Political and Economic Studies
3:50	John Hanger	PA Dept of Environmental Protection Hanger Consulting
3:55	Teresa Mendez-Quigley	Women's Health and Environmental Network
4:00	Amy Roe	Individual
4:05	Geneva Boyer	Individual
4:10	Shreena Bindra	Individual
3:55	Coralie A. Pryde	Individual
4:00	Josh Nelson	CREDO Action from Working Assets
4:20	Jeff A McNelly	ARIPPA
4:25	Brenda Afzal	HCWH, U.S. Climate Policy Coordinator
4:30	Ed Braun	City of Philadelphia Department of Public Health, Air Management Services
4:35	Mary Anne Rushlau	Sierra Club
4:40	Jenny Kordick	Individual
4:45	Bruce Alexander	Exelon Corporation
4:50	Kate Etherington	Philadelphia Physicians for Social Responsibility
4:55	Alex Milone	
5:00	Mandy Warner	Environmental Defense Fund
5:05	Katie Edwards	Individual
5:10	Phillipa Strahm	League of Conservation Voters
5:15	James Grande	Sierra Club

Time	Name	Affiliation
5:20	James Kelley	Individual
5:25	Freyda Black	Individual
6:45	Al Rizzo	American Lung Association
6:50	Matthew Pale	PennEnvironment
6:55	Joe Parrish	American Lung Association of New Jersey
7:00	Kendall Mackey	National Wildlife Federation
7:05	Adam H. Cutler	Public Health and Environmental Justice Law Clinic
7:10	Rachel Mentin	Individual
7:15	Lynn Jaeger	Eastern MontCo Action
7:20	Captain Joel Fogel	Waterwatch International
7:25	Kate Zaidan	Individual
7:30	Myriam Fallon	Greenpeace
7:35	Christina Marie Glessner	Individual
7:40	Rosa Michmya	Individual
7:30	Dr. Gwen DuBois	Chesapeake Physicians for Social Responsibility
7:35	Dr. Cindy Parker	Chesapeake Physicians for Social Responsibility
7:40	Jeff Player	Individual
7:45	Lisa Hastings	Individual
7:50	Stephen Shapiro	Chesapeake Physicians for Social Responsibility
7:55	Hollister Knowlton	National Council of Churches and the Quaker Earthcare Ministry
8:00	Georgina Shanley	Citizens United for Renewable Energy
8:05	Steven Fenichel	Citizens United for Renewable Energy
8:10	Miranda Outman	
8:15	Martin Hage	Individual
8:20	Ann Dixon	Penn Environment
8:25	Jay Fabrikant	Individual

APPENDIX B: LIST OF COMMENTERS

DCN	Commenter Name	Commenter Affiliation
EPA-HQ-OAR-2009-0234-6543-A1	Chris M. Hobson	Southern Company
EPA-HQ-OAR-2009-0234-6584-A1	Sheila C. Holman	North Carolina Department of Environment and Natural Resources (NCDENR), Division of Air Quality (NC DAQ)
EPA-HQ-OAR-2009-0234-6637-A1	Naomi Goodman	Electric Power Research Institute (EPRI)
EPA-HQ-OAR-2009-0234-6640-A1	A. Mellinger-Birdsong	None
EPA-HQ-OAR-2009-0234-8443-A1	Theresa Pugh	American Public Power Association (APPA)
EPA-HQ-OAR-2009-0234-9738-A1	H. Tsourous	None
EPA-HQ-OAR-2009-0234-10167-A1	Mike Roddy	Seminole Electric Cooperative, Inc
EPA-HQ-OAR-2009-0234-10569-A1	Juan Ramirez	Florida Electric Power Coordinating Group, Inc. (FCG)
EPA-HQ-OAR-2009-0234-10750-A1	John M. McManus	American Electric Power (AEP)
EPA-HQ-OAR-2009-0234-10821-A2	Michael J. Nasi	Jackson Walker, LLP on behalf of Gulf Coast Lignite Coalition (GCLC)
EPA-HQ-OAR-2009-0234-10822-A2	L. Mohorovic, PhD	None
EPA-HQ-OAR-2009-0234-10942-A1	John D. Free	Alabama Public Service Commission (APSC)
EPA-HQ-OAR-2009-0234-10943-A1	James O. Vick	Gulf Power Company
EPA-HQ-OAR-2009-0234-10944-A1	Charles McPhedran	Citizens for Pennsylvania's Future (PennFuture)
EPA-HQ-OAR-2009-0234-10987-A1	Rae Cronmiller, James J. Nipper	National Rural Electric Cooperative Association (NRECA), American Public Power Association (APPA)
EPA-HQ-OAR-2009-0234-11107-A1	Alan H. Lockwood	None
EPA-HQ-OAR-2009-0234-11889	Douglas K. Stevens	None
EPA-HQ-OAR-2009-0234-12050-A2	Thomas Au	Clean Air Board of Central Pennsylvania (CAB)
EPA-HQ-OAR-2009-0234-12267-A1	S. W. Kuntz, PhD	
EPA-HQ-OAR-2009-0234-12380-A2	Anonymous public comment	None

EPA-HQ-OAR-2009-0234-12462-A1	Lee Sprague	Little River Band of Ottawa Indians
EPA-HQ-OAR-2009-0234-12798-A2	Alisa Gravitz	Green America
EPA-HQ-OAR-2009-0234-12991-A1	Jeffrey Quick	Utah Geological Survey, Utah Department of Natural Resources
EPA-HQ-OAR-2009-0234-12996-A2	Michael P. Halpin	Division of Air Resource Management, Florida Department of Environmental Protection (DEP)
EPA-HQ-OAR-2009-0234-13178-A1	Patrick O'Loughlin	Buckeye Power, Inc.
EPA-HQ-OAR-2009-0234-13526-A1	Susana M. Hildebrand	Texas Commision on Environmental Quality (TCEQ)
EPA-HQ-OAR-2009-0234-13529-A1	Byron T. Burrows	Tampa Electric Company (TECO)
EPA-HQ-OAR-2009-0234-13827-A1	Darrell Dorsey	Kansas City Board of Public Utilities (BPU)
EPA-HQ-OAR-2009-0234-14017-A1	David R. Tripp and Dennis Lane	Stinson Morrison Hecker LLP on behalf of Westar Energy, Inc.
EPA-HQ-OAR-2009-0234-14069-A1	Raymond L. Evans	FirstEnergy Corp.
EPA-HQ-OAR-2009-0234-14070-A1	G. Vinson Hellwig	Michigan Department of Environmental Quality (MDEQ)
EPA-HQ-OAR-2009-0234-14070-A2	G. Vinson Hellwig	Michigan Department of Environmental Quality (MDEQ)
EPA-HQ-OAR-2009-0234-14115-A1	Dr. W. Soon	None
EPA-HQ-OAR-2009-0234-14368-A1	Niger Innis	Congress of Racial Equality on behalf of Affordable Power Alliance (APA)
EPA-HQ-OAR-2009-0234-15002-A1	Barbara Gottlieb	Physicians for Social Responsibility (PSR)
EPA-HQ-OAR-2009-0234-15160-A1	Dr. Lawrence Raymond	Clean Air Carolina
EPA-HQ-OAR-2009-0234-15182-A2	James Zorn	Great Lakes Indian Fish and Wildlife Commission (GLIFWC)
EPA-HQ-OAR-2009-0234-15678-A2	William Skrabak	Transportation and Environmental Services, Office of Environmental Quality, City of Alexandria, Virginia
EPA-HQ-OAR-2009-0234-15884-A2	Joseph Otis Minott	Clean Air Council
EPA-HQ-OAR-2009-0234-16121-A1	Cynthia Bearer, Board Chair	Children's Environmental Health Network (CEHN)
EPA-HQ-OAR-2009-0234-16122-A1	Harold "Gus" Frank	Forest County Potawatomi Community (FCPC)

EPA-HQ-OAR-2009-0234-16207-A1	Nancy F. Parks	Sierra Club
EPA-HQ-OAR-2009-0234-16402-A1	Joseph S. Hensel	Rochester Public Utilities
EPA-HQ-OAR-2009-0234-16403-A1	Paul Bailey	American Coalition for Clean Coal Electricity (ACCCE)
EPA-HQ-OAR-2009-0234-16404-A1	Charles D. Connor	American Lung Association
EPA-HQ-OAR-2009-0234-16405-A1	Art Graham	Florida Public Service Commission (FPSC)
EPA-HQ-OAR-2009-0234-16469-A1	Bill Banig and Jim Hunter	Unions for Jobs and the Environment (UJAE)
EPA-HQ-OAR-2009-0234-16513-A1	Daniel C. Esty	Connecticut Department of Energy and Environmental Protection
EPA-HQ-OAR-2009-0234-16549-A1	Lance Brown et al.	Partnership for Affordable Clean Energy (PACE)
EPA-HQ-OAR-2009-0234-16626-A1	Congressman John D. Dingell, et al.	Congress of the United States
EPA-HQ-OAR-2009-0234-16627-A1	Illona A. Jeffcoat-Sacco	North Dakota Public Service Commission
EPA-HQ-OAR-2009-0234-16630-A1	Ellen Rendulich	Citizens Against Ruining the Environment (CARE)
EPA-HQ-OAR-2009-0234-16682-A1	Juliet Cohen	Upper Chattahoochee Riverkeepers
EPA-HQ-OAR-2009-0234-16705-A2	William H. Conrad	City of Newberry, Florida
EPA-HQ-OAR-2009-0234-16738-A1	Leonard Levin	Electric Power Research Institute (EPRI)
EPA-HQ-OAR-2009-0234-16822-A1	Senator James A. Inhofe, et al.	Congress of the United States
EPA-HQ-OAR-2009-0234-16824-A2	Chris Clark	Georgia Chamber of Commerce
EPA-HQ-OAR-2009-0234-16826-A1	Brian Saylor	American Lung Association
EPA-HQ-OAR-2009-0234-16844-A1	John A. Arway	Pennsylvania Fish and Boat Commission (PFBC)
EPA-HQ-OAR-2009-0234-16849-A1	Rebecca Heffren	Empire District Electric Company
EPA-HQ-OAR-2009-0234-16850-A2	Cindy B. Miller	Florida Public Service Commission
EPA-HQ-OAR-2009-0234-16856-A1	Tom Bloss	Pritchard Electric
EPA-HQ-OAR-2009-0234-16857-A1	Caroline Choi	Progress Energy
EPA-HQ-OAR-2009-0234-16858-A1	R.D. Cross	Gilmer, TX
EPA-HQ-OAR-2009-0234-16859-A1	Leo M. Drozdoff	Environmental Council of the States (ECOS)
EPA-HQ-OAR-2009-0234-16861-A1	Thomas R. Kuhn	Edison Electric Institute (EEI)
EPA-HQ-OAR-2009-0234-16872-A1	Tony Clark	National Association of Regulatory Utility Commissioners

		(NARUC)
EPA-HQ-OAR-2009-0234-16873-A1	Thomas W. McNamee	Public Utilities Commission Ohio (PUCO)
EPA-HQ-OAR-2009-0234-17003-A1	Scott H. Segal	Electric Reliability Coordinating Council (ERCC)
EPA-HQ-OAR-2009-0234-17004-A1	Billy Ray Jones	City of Nashville, Arkansas
EPA-HQ-OAR-2009-0234-17022-A1	Charles Waldon	Town of Stonewall, Louisiana
EPA-HQ-OAR-2009-0234-17026-A1	David R. Rockett, Jr.	Greater Bossier Economic Development Foundation
EPA-HQ-OAR-2009-0234-17028-A1	Carson C. Joines	City of Carthage, Texas
EPA-HQ-OAR-2009-0234-17055-A1	Nicholas A. Brown	Southwest Power Pool, Inc. (SPP)
EPA-HQ-OAR-2009-0234-17110-A1	Michael Bradley	Clean Energy Group's Clean Air Policy Initiative
EPA-HQ-OAR-2009-0234-17114-A1	Rosemary Elebash	National Federation of Independent Business (NFIB)
EPA-HQ-OAR-2009-0234-17123-A1	Andrew J. Such	Michigan Manufacturers Association (MMA)
EPA-HQ-OAR-2009-0234-17137-A1	Mike Arms	Association of Tennessee Valley Governments (ATVG)
EPA-HQ-OAR-2009-0234-17157-A1	Evelyn Fang	Leadership Council Alaska, American Lung Association
EPA-HQ-OAR-2009-0234-17174-A2	Myra C. Reece	Bureau of Air Quality, South Carolina Department of Health and Environmental Control (DHEC)
EPA-HQ-OAR-2009-0234-17191-A2	Terry Hogan	Wabash Valley Power Association (WVPA)
EPA-HQ-OAR-2009-0234-17197-A1	Paul Schulz	Platte River Power Authority
EPA-HQ-OAR-2009-0234-17254-A1	Public Hearing in Atlanta, GA on May 26, 2011	
EPA-HQ-OAR-2009-0234-17265-A1	Michael P. Halpin	Division of Air Resource Management, Florida Department of Environmental Protection (FDEP)
EPA-HQ-OAR-2009-0234-17270	V. Watson	None
EPA-HQ-OAR-2009-0234-17278-A1	Donald H. Picard	Southeast Volusia Audubon Society chapter of the National Audubon Society
EPA-HQ-OAR-2009-0234-17279	Mark Mueller	St. Petersburg chapter of the National Audubon Society
EPA-HQ-OAR-2009-0234-17281-A2	Kenneth J. Schilling	Washington Electric Cooperative, Inc.

EPA-HQ-OAR-2009-0234-17283-A1	Carli Smith et al.	Cooper Environmental Services, LLC (CES)
EPA-HQ-OAR-2009-0234-17291	Anonymous public comment	None
EPA-HQ-OAR-2009-0234-17294	L. McClain	None
EPA-HQ-OAR-2009-0234-17295-A2	L. J. Joey Durel, Jr.,	Lafayette Consolidated Government on behalf of Lafayette Utilities System
EPA-HQ-OAR-2009-0234-17296-A2	Marshall D. Moore	Chemtura Corporation
EPA-HQ-OAR-2009-0234-17297-A2	Orjiakor N. Isiogu, Monica Martinez, and Greg R. White	Department of Licensing and Regulatory Affairs, Michigan Public Service Commission
EPA-HQ-OAR-2009-0234-17299-A2	George Carter	Paulding Putnam Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17305-A2	Gerald Lauer	Consolidated Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17306-A2	Glenn W. Miller	Holmes-Wayne Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17316-A2	B. Machaver	None
EPA-HQ-OAR-2009-0234-17381	Jon Hinck	Maine House of Representatives
EPA-HQ-OAR-2009-0234-17383-A1	John T. Graves	Minnkota Power Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17385-A2	Floyd DesChamps	Alliance to Save Energy
EPA-HQ-OAR-2009-0234-17386-A2	Richard Vélez	Taunton Municipal Lighting Plant (TMLP)
EPA-HQ-OAR-2009-0234-17400-A1	Eugene F. Wallace and Paul H. Beckhusen	Coldwater Board of Public Utilities, City of Coldwater, Michigan
EPA-HQ-OAR-2009-0234-17401-A1	Jay Vavricek and Timothy Luchsinger	City of Grand Island, Nebraska
EPA-HQ-OAR-2009-0234-17402-A1	Basil G. Constantelos	Edison Mission Energy, LLC
EPA-HQ-OAR-2009-0234-17403-A1	Anthony N. Jacobs	International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers and AFL-CIO (Boilermakers Union)
EPA-HQ-OAR-2009-0234-17405-A1	Jennifer Lust	Brainerd Lakes Area Audubon Society
EPA-HQ-OAR-2009-0234-17406-A1	Raymond Burns	Rogers-Lowell Area Chamber of Commerce

EPA-HQ-OAR-2009-0234-17408-A1	Public Hearing in Chicago, IL on May 24, 2011	
EPA-HQ-OAR-2009-0234-17409-A1	Public Hearing in Philadelphia, PA on May 24, 2011	
EPA-HQ-OAR-2009-0234-17608-A1	Winslow Sargeant	Small Business Administration (SBA)
EPA-HQ-OAR-2009-0234-17620-A1	S. William Becker	National Association of Clean Air Agencies (NACAA)
EPA-HQ-OAR-2009-0234-17621-A1	Paul Chu	Electric Power Research Institute (EPRI)
EPA-HQ-OAR-2009-0234-17622-A1	David Foerter	Institute of Clean Air Companies (ICAC)
EPA-HQ-OAR-2009-0234-17623-A1	Brian H. Moeck	Large Public Power Council (LPPC)
EPA-HQ-OAR-2009-0234-17625-A1	Ronald Poltak	New England Interstate Water Pollution Control Commission (NEIWPCC)
EPA-HQ-OAR-2009-0234-17626-A1	Robert G. Hilton	Power Technologies for Government Affairs, Alstom
EPA-HQ-OAR-2009-0234-17627-A1	Raymond L. Evans	FirstEnergy Corp. (FE)
EPA-HQ-OAR-2009-0234-17628-A1	Les Oakes	King & Spalding LLP on behalf of Power4Georgians, LLC (P4G)
EPA-HQ-OAR-2009-0234-17629-A1	John V. Corra	Wyoming Department of Environmental Quality
EPA-HQ-OAR-2009-0234-17637-A1	Ruthanne F. Calabrese	Northeast Utilities System Company (NUSCO)
EPA-HQ-OAR-2009-0234-17638-A1	James O. Vick	Florida Electric Power Coordinating Group, Inc. (FCG)
EPA-HQ-OAR-2009-0234-17639-A1	Terry E. Branstad, Governor	State of Iowa
EPA-HQ-OAR-2009-0234-17640-A1	Paul A. Yost	National Association of Manufacturers (NAM)
EPA-HQ-OAR-2009-0234-17648-A2	Kathleen Barron	Exelon Corporation (Part 1 of 3)
EPA-HQ-OAR-2009-0234-17654-A1	David E. Meehan	Sunbury Generation LP
EPA-HQ-OAR-2009-0234-17655-A1	David M. Fraley	City Utilities of Springfield, Missouri (CU)
EPA-HQ-OAR-2009-0234-17656-A1	Holly Propst	Western Business Roundtable
EPA-HQ-OAR-2009-0234-17657-A1	Joan Small	Gilmer Area Chamber of Commerce
EPA-HQ-OAR-2009-0234-17658-A1	Lynda Munkres,	Morris County, TX

	Judge	
EPA-HQ-OAR-2009-0234-17659-A1	Kelly R. Hall	Real East Texas Longview Chamber of Commerce
EPA-HQ-OAR-2009-0234-17660-A1	J. W. Fullen, Mayor	City of Henderson, TX
EPA-HQ-OAR-2009-0234-17661-A1	Charles Thomas	Carthage Economic Development Corporation
EPA-HQ-OAR-2009-0234-17674-A1	Charles L. Franklin	Akin Gump Strauss Hauer & Feld LLP on behalf of Gila River Indian Community
EPA-HQ-OAR-2009-0234-17675-A1	Brian Brazil	TransAlta Centralia Generation LLC
EPA-HQ-OAR-2009-0234-17676-A1	Ellen Bloom et al.	Consumers Union
EPA-HQ-OAR-2009-0234-17677-A1	Tim Mordhorst	Black Hills Corporation (BH)
EPA-HQ-OAR-2009-0234-17678-A1	Eric Redman	Summit Texas Clean Energy, LLC
EPA-HQ-OAR-2009-0234-17679-A1	David Evers	Biodiversity Research Institute (BRI)
EPA-HQ-OAR-2009-0234-17680-A1	David Chadwick, Mayor	City of Center, TX
EPA-HQ-OAR-2009-0234-17681-A1	Farzie Shelton	Lakeland Electric
EPA-HQ-OAR-2009-0234-17682-A1	Steven C. Borell	Alaska Miners Association (AMA)
EPA-HQ-OAR-2009-0234-17683-A1	Tim Gestwicki and Dick Hamilton	North Carolina (NC) Wildlife Federation and North Carolina Camouflage Coalition
EPA-HQ-OAR-2009-0234-17684-A1	Judy Sewell	Henderson Area Chamber of Commerce
EPA-HQ-OAR-2009-0234-17685-A1	Bobby Beane	Kilgore Economic Development Corporation
EPA-HQ-OAR-2009-0234-17686-A1	Alan Grantham and Connie Ware	Marshall Chamber of Commerce
EPA-HQ-OAR-2009-0234-17689-A1	Rae E. Cronmiller	The National Rural Electric Cooperative Association (NRECA)
EPA-HQ-OAR-2009-0234-17690-A1	Roger Caiazza	Environmental Energy Alliance of New York, LLC
EPA-HQ-OAR-2009-0234-17691-A1	John S. Lyons	Commonwealth of Kentucky, Division for Air Quality
EPA-HQ-OAR-2009-0234-17692-A1	Daniel L. Juneau	Louisiana Association of Business and Industry (LABI)
EPA-HQ-OAR-2009-0234-17693-A1	Stephen J. Metcalf and Susan	Longview Economic Development Corporation

	Mazarakes-Gill	
EPA-HQ-OAR-2009-0234-17694-A1	Lynda Rauscher	Mineola, Texas, Community Development Department
EPA-HQ-OAR-2009-0234-17695-A1	Sue Henderson	Henderson Economic Development Corporation
EPA-HQ-OAR-2009-0234-17696-A2	Linda Whelan	Dynegy, Inc.
EPA-HQ-OAR-2009-0234-17697-A1	Edward J. B. Calvo	Governor of Guam on behalf of Guam Power Authority (GPA)
EPA-HQ-OAR-2009-0234-17698-A1	Joaquin C. Flores	Guam Power Authority (GPA)
EPA-HQ-OAR-2009-0234-17699-A1	Alexander Jackson	Fond du Lac Band of Lake Superior Chippewa
EPA-HQ-OAR-2009-0234-17700-A1	R. E. Spradlin, III, Mayor	Kilgore, TX
EPA-HQ-OAR-2009-0234-17701-A1	Robin J. Lunt	National Association of Regulatory Utility Commissioners (NARUC)
EPA-HQ-OAR-2009-0234-17702-A1	Robert E. Hunzinger	Gainesville Regional Utilities (GRU)
EPA-HQ-OAR-2009-0234-17703-A1	Ronald W. Gore	Alabama Department of Environmental Management (ADEM)
EPA-HQ-OAR-2009-0234-17704-A1	Angela Rodriguez	City Public Service (CPS Energy)
EPA-HQ-OAR-2009-0234-17705-A1	Kevin Wanttaja	Salt River Project (SRP)
EPA-HQ-OAR-2009-0234-17707-A1	Jack Pelfrey	Eufaula Barbour County Chamber of Commerce
EPA-HQ-OAR-2009-0234-17708-A1	E. F. Whitus, Mayor	Mineola, Texas
EPA-HQ-OAR-2009-0234-17709-A1	Bruce Caswell, State Senator	State of Michigan
EPA-HQ-OAR-2009-0234-17710-A1	Senator Thomas C. Ada	Committee on Utilities, Transportation, Public Works, and Veterans Affairs of the 31st Guam Legislature
EPA-HQ-OAR-2009-0234-17711-A1	Paul Noe and Robert Glowinski	American Forest & Paper Association (AF&PA) and American Wood Council (AWC)
EPA-HQ-OAR-2009-0234-17712-A1	Leonard F. Hopkins	Southern Illinois Power Cooperative (SIPC)
EPA-HQ-OAR-2009-0234-17713-A1	Niger Innis	Affordable Power Alliance
EPA-HQ-OAR-2009-0234-17714-A1	Nicholas M. Dernik	Northern Indiana Public Service Company (NIPSCO)
EPA-HQ-OAR-2009-0234-17715-A1	David E. Jones	Ohio Valley Electric Corporation (OVEC)/Indiana Kentucky

		Electric Corporation (IKEC)
EPA-HQ-OAR-2009-0234-17716-A1	Dennis Lane	Stinson Morrison Hecker LLP on behalf of Westar Energy, Inc.
EPA-HQ-OAR-2009-0234-17717-A1	Lorenz Walker, Mayor	Bossier City, LA
EPA-HQ-OAR-2009-0234-17718-A1	Reid T. Clemmer	PPL Corporation
EPA-HQ-OAR-2009-0234-17719-A1	Martha E. Rudolph	Colorado Department of Public Health and Environment
EPA-HQ-OAR-2009-0234-17720-A1	Angila M. Retherford	Vectren Corporation
EPA-HQ-OAR-2009-0234-17721-A1	Winston & Strawn LLP	on behalf of Chem-Mod LLC
EPA-HQ-OAR-2009-0234-17722-A1	Mary Jo Roth	Great River Energy (GRE)
EPA-HQ-OAR-2009-0234-17723-A1	David M. Fraley	City Utilities of Springfield, Missouri (CU)
EPA-HQ-OAR-2009-0234-17724-A1	John W. Dwyer	Lignite Energy Council (LEC)
EPA-HQ-OAR-2009-0234-17725-A1	Verne Shortell	NRG Energy, Inc.
EPA-HQ-OAR-2009-0234-17727-A1	John Proos, et al., State Senate	State of Michigan
EPA-HQ-OAR-2009-0234-17728-A1	Douglas J. Fulle	Oglethorpe Power Corporation
EPA-HQ-OAR-2009-0234-17729-A1	Bruce Parker	Electric Energy, Inc. (EEI)
EPA-HQ-OAR-2009-0234-17730-A1	Barbara A. Walz	Tri-State Generation & Transmission Association, Inc.
EPA-HQ-OAR-2009-0234-17731-A1	Parthenia B. Evans and Dennis Lane	Stinson Morrison Hecker LLP on behalf of the Kansas City Board of Public Utilities (BPU)
EPA-HQ-OAR-2009-0234-17732-A1	Stephen B. Etsitty	Navajo Nation Environmental Protection Agency
EPA-HQ-OAR-2009-0234-17733-A1	Harold “Gus” Frank and James Crawford	Forest County Potawatomi Community (FCPC)
EPA-HQ-OAR-2009-0234-17734-A1	Ed Williams	Novinda Corporation
EPA-HQ-OAR-2009-0234-17735-A1	Wayne E. Penrod	Coalition of New Units
EPA-HQ-OAR-2009-0234-17736-A1	Ryan D. Elliott	Shumaker, Loop & Kendrick, LLP on behlaf of Ohio Utility Group
EPA-HQ-OAR-2009-0234-17737-A1	Arie Hoekstra	Tucson Electric Power Company (TEP)
EPA-HQ-OAR-2009-0234-17738-A1	Derek R. McDonald	Baker Botts LLP on behalf of the IPA Coleto Creek LLC (IPA)
EPA-HQ-OAR-2009-0234-17739-A1	Neal J. Cabral	McguireWoods LLP on behalf of CONSOL Energy, Inc.

EPA-HQ-OAR-2009-0234-17740-A1	William M. Bumpers	Baker Botts L.L.P., on behalf of Class of 1985 Regulatory Response Group
EPA-HQ-OAR-2009-0234-17741-A1	Stephen R. Lindauer	The Association of Union Constructors (TAUC)
EPA-HQ-OAR-2009-0234-17743-A1	E. Scott Pruitt, Attorney General	State of Oklahoma
EPA-HQ-OAR-2009-0234-17745-A1	Samuel S. Olens, Attorney General	State of Georgia
EPA-HQ-OAR-2009-0234-17747-A1	Krag Petterson	Pall Corporation
EPA-HQ-OAR-2009-0234-17748-A1	Charles L. Hardy Jr., Mayor	City of Commerce, Georgia
EPA-HQ-OAR-2009-0234-17749-A1	Jeff Lewis	Fitzgerald Water, Light & Bond Commission
EPA-HQ-OAR-2009-0234-17750-A1	Charlie Denham	Crisp County Power Commission
EPA-HQ-OAR-2009-0234-17751-A1	William L. Kovacs	U.S. Chamber of Commerce
EPA-HQ-OAR-2009-0234-17752-A1	Mark Thoma	Otter Tail Power Company
EPA-HQ-OAR-2009-0234-17753-A1	Jason D. Bostic	West Virginia Coal Association (WVCA)
EPA-HQ-OAR-2009-0234-17754-A1	Jeff McNelly	ARIPPA
EPA-HQ-OAR-2009-0234-17755-A1	Eddie Terrill	Oklahoma Department of Environmental Quality (ODEQ)
EPA-HQ-OAR-2009-0234-17756-A1	Paul M. Ling	Kansas City Power & Light Company (KCP&L
EPA-HQ-OAR-2009-0234-17757-A1	Patrick O'Loughlin	Buckeye Power, Inc.
EPA-HQ-OAR-2009-0234-17758-A1	Thomas R. Kuhn	Edison Electric Institute (EEI)
EPA-HQ-OAR-2009-0234-17760-A1	William M. Bumpers	Baker Botts L.L.P., on behalf of Class of 1985 Regulatory Response Group
EPA-HQ-OAR-2009-0234-17761-A1	Cathy S. Woollums	Mid American Energy Holdings Company
EPA-HQ-OAR-2009-0234-17763-A1	Camille Payne, Mayor	Thomasville, GA
EPA-HQ-OAR-2009-0234-17765-A1	John T. Heard	The Virginia Coal Association, Inc. (VCA)
EPA-HQ-OAR-2009-0234-17766-A1	Dennis M. Grzezinski	Midwest Environmental Advocates, Inc. (MEA)
EPA-HQ-OAR-2009-0234-17767-A1	PJ Becker	City of Springfield, Illinois - City Water Light & Power (CWLP)
EPA-HQ-OAR-2009-0234-17768-A1	Michael A. Livermore et al.	Institute for Policy Integrity, New York University School of Law
EPA-HQ-OAR-2009-0234-17769-A1	Mike Roddy	Seminole Electric Cooperative, Inc.

EPA-HQ-OAR-2009-0234-17770-A1	Bruce W. Ramme	We Energies
EPA-HQ-OAR-2009-0234-17771-A1	Dave Martin	New Mexico Environment Department (NMED)
EPA-HQ-OAR-2009-0234-17772-A1	JoAnne Rau	Dayton Power and Light Company (DP&L)
EPA-HQ-OAR-2009-0234-17773-A1	Leonard Levin	Electric Power Research Institute (EPRI)
EPA-HQ-OAR-2009-0234-17774-A1	Jay Hudson	Santee Cooper
EPA-HQ-OAR-2009-0234-17775	None	Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2009-0234-17775-A1	Lee B. Zeugin et. al Hunton and Williams LLP	on behalf of Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2009-0234-17776-A1	Patricia D. Horn	Oklahoma Gas And Electric Company (OGandE)
EPA-HQ-OAR-2009-0234-17777-A1	Hunton and Williams LLP	on behalf of Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2009-0234-17778-A1	Willie E. Burns, Mayor	City of Washington, Georgia
EPA-HQ-OAR-2009-0234-17779-A1	Albert Doughty, Mayor	Town of Benton, Louisiana
EPA-HQ-OAR-2009-0234-17780-A1	Mary Jo Graham	Oakmoss Education
EPA-HQ-OAR-2009-0234-17781-A1	Hunton and Williams LLP	on behalf of Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2009-0234-17782-A1	Rosemary Elebash	National Federation of Independent Business (NFIB)
EPA-HQ-OAR-2009-0234-17783-A1	Kenneth D. Roberts	City of Barnesville, Georgia
EPA-HQ-OAR-2009-0234-17784-A1	Hunton and Williams LLP	on behalf of Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2009-0234-17785-A1	Hunton and Williams LLP	on behalf of Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2009-0234-17786-A1	Lauren Freeman	Hunton & Williams LLP on behalf of Utility Air Regulatory Group
EPA-HQ-OAR-2009-0234-17787-A1	Lauren Freeman	Hunton & Williams LLP on behalf of Utility Air Regulatory Group
EPA-HQ-OAR-2009-0234-17788-A1	Scott Getzschman and Derril Marshall	Fremont Department of Utilities, Nebraska
EPA-HQ-OAR-2009-0234-17789-A2	Scott M. Lorey	Adirondack Council
EPA-HQ-OAR-2009-0234-17790-A2	William Rogers	DTE Energy
EPA-HQ-OAR-2009-0234-17791-A2	Robin J. Lunt	National Association of Regulatory Utility Commissioners (NARUC)

EPA-HQ-OAR-2009-0234-17792-A1	L. J. "Joey" Durel, Jr.	Lafayette Consolidated Government on behalf of Lafayette Utilities System et al.
EPA-HQ-OAR-2009-0234-17795-A1	Brian W. Green	GenOn Energy, Inc.
EPA-HQ-OAR-2009-0234-17796-A1	J. Jared Snyder	New York State Department of Environmental Conservation (NYSDEC)
EPA-HQ-OAR-2009-0234-17797-A1	Eldon Long, Mayor	City of Lowell, Arkansas
EPA-HQ-OAR-2009-0234-17798-A1	William B. Baumann	Wisconsin Department of Natural Resources (WDNR)
EPA-HQ-OAR-2009-0234-17799-A1	Paul Bailey	American Coalition for Clean Electricity (ACCCE)
EPA-HQ-OAR-2009-0234-17800	Steven C. Whitworth	Ameren Corporation
EPA-HQ-OAR-2009-0234-17800-A1	Steven C. Whitworth	Ameren Corporation
EPA-HQ-OAR-2009-0234-17801-A1	Steve Meyers	General Electric Company (GE)
EPA-HQ-OAR-2009-0234-17803-A1	Robert D. Teetz	National Grid
EPA-HQ-OAR-2009-0234-17804-A1	Michael L. Krancer	Pennsylvania Department of Environmental Protection (DEP)
EPA-HQ-OAR-2009-0234-17805-A1	Abbie Krebsbach	Montana-Dakota Utilities Company
EPA-HQ-OAR-2009-0234-17806-A1	Henry R. Darwin	Arizona Department of Environmental Quality (ADEQ)
EPA-HQ-OAR-2009-0234-17807	Thomas L. Hernandez	Tampa Electric Company (TEC)
EPA-HQ-OAR-2009-0234-17807-A1	Thomas L. Hernandez	Tampa Electric Company (TEC)
EPA-HQ-OAR-2009-0234-17808-A1	Michael Bradley	The Clean Energy Group
EPA-HQ-OAR-2009-0234-17809-A1	Mike Roddy	Seminole Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17810-A1	Regina Hopper	America's Natural Gas Alliance (ANGA)
EPA-HQ-OAR-2009-0234-17811-A1	J. Dorgan and M. D. Gibson Lindblom on behalf of Michael Churchman	Alabama Environmental Council et al.
EPA-HQ-OAR-2009-0234-17812-A1	Robert D. Bessette	Council of Industrial Boiler Owners (CIBO)
EPA-HQ-OAR-2009-0234-17813-A1	Joseph G. Eutizi	San Miguel Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17814-A1	James O. Vick	Gulf Power Company

EPA-HQ-OAR-2009-0234-17815-A1	John W. Fainter, Jr.	Association of Electric Companies of Texas (AECT)
EPA-HQ-OAR-2009-0234-17816-A1	Michael L. Jones	Puget Sound Energy, Inc.
EPA-HQ-OAR-2009-0234-17817-A1	Wayne E. Penrod	Sunflower Electric Power Corporation
EPA-HQ-OAR-2009-0234-17818-A2	Ronald A. Amirikian	State of Delware, Department of Natural Resources & Environmental Control, Division of Air and Waste Management
EPA-HQ-OAR-2009-0234-17819-A2	Keith Harley	Environment Illinois, Chicago Legal Clinic, Inc. on behalf of Environmental Law and Policy Center (ELPC)
EPA-HQ-OAR-2009-0234-17820-A1	Pamela F. Faggert	Dominion
EPA-HQ-OAR-2009-0234-17820-A2	Pamela F. Faggert	Dominion
EPA-HQ-OAR-2009-0234-17821-A1	John L. Stowell	Duke Energy
EPA-HQ-OAR-2009-0234-17822-A1	Richard Barr, Mayor	Adel, GA
EPA-HQ-OAR-2009-0234-17823-A1	Woodrow Wilson, Jr.	Parrish of Caddo
EPA-HQ-OAR-2009-0234-17824-A1	Peter B. Storey	Childersburg Chamber of Commerce
EPA-HQ-OAR-2009-0234-17825-A1	Keith Brady, Mayor	Newnan, GA
EPA-HQ-OAR-2009-0234-17826-A1	Peter L. Banks, Mayor	Barnesville, GA
EPA-HQ-OAR-2009-0234-17827-A1	J.D. Herring	Quitman, GA
EPA-HQ-OAR-2009-0234-17829-A1	Fred Hlava,	Gordon, NE
EPA-HQ-OAR-2009-0234-17830-A1	Dan Leise	Cedar-Knox Public Power District (CKPPD)
EPA-HQ-OAR-2009-0234-17831-A1	Neal D. Suess	Loup River Public Power District
EPA-HQ-OAR-2009-0234-17833-A1	David P. Hackett and Jessica Mitchell Wicha, Baker & McKenzie LLP	on behalf of Michael A. Gardner Gypsum Association
EPA-HQ-OAR-2009-0234-17834-A1	Jon Bruning	State of Nebraska et al.
EPA-HQ-OAR-2009-0234-17835-A1	David M. Fraley	City Utilities of Springfield, Missouri (CU)
EPA-HQ-OAR-2009-0234-17836	John T. Suttles	Southern Environmental Law Center (SELC)
EPA-HQ-OAR-2009-0234-17836-A1	John T. Suttles, Jr.,	Southern Environmental Law Center (SELC) and Southeast

		Environmental Organizations
EPA-HQ-OAR-2009-0234-17837-A2	Thomas Holbrook, Illinois State Representative	Illinois General Assembly, 113th District
EPA-HQ-OAR-2009-0234-17838-A2	R. J. Shaffer	Scrubgrass Generating Company L.P.
EPA-HQ-OAR-2009-0234-17839-A2	Wallace L. Taylor	Sierra Club Iowa Chapter
EPA-HQ-OAR-2009-0234-17840-A2	William D. Bissett	Kentucky Coal Association (KCA)
EPA-HQ-OAR-2009-0234-17841-A2	Craig S. Campbell	Lafarge North America-Cement Division
EPA-HQ-OAR-2009-0234-17842-A2	Kevin Cramer	North Dakota Public Service Commission (NDPSC) et al.
EPA-HQ-OAR-2009-0234-17843-A2	Arthur N. Marin	Northeast States for Coordinated Air Use Management (NESCAUM)
EPA-HQ-OAR-2009-0234-17844-A2	Mindy Lubber	Ceres
EPA-HQ-OAR-2009-0234-17845-A2	C. Richard Neff	Cogentrix Energy, LLC
EPA-HQ-OAR-2009-0234-17846-A2	Alex Jackson	Fond du Lac Band of Lake Superior Chippewa
EPA-HQ-OAR-2009-0234-17848-A2	Travis J. Blake	Division of Air Pollution Control, Tennessee Department of Environment and Conservation
EPA-HQ-OAR-2009-0234-17849-A2	Garry A. Mbiad	Guernsey-Muskingum Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17850-A1	Jeff A. McNelly	ARIPPA
EPA-HQ-OAR-2009-0234-17851-A2	Melvin E. Keener	Coalition for Responsible Waste Incineration (CRWI)
EPA-HQ-OAR-2009-0234-17852-A2	Gregory C. Staple	American Clean Skies Foundation (ACSF)
EPA-HQ-OAR-2009-0234-17853-A2	Matt Most	Encana Natural Gas, Inc.
EPA-HQ-OAR-2009-0234-17854-A1	Kristina Curtis	Green Century Capital Management
EPA-HQ-OAR-2009-0234-17855-A2	David A. Kellermeyer	Northern Star Generation, LLC
EPA-HQ-OAR-2009-0234-17856-A2	Scott J. Nally	Ohio Environmental Protection Agency (Ohio EPA)
EPA-HQ-OAR-2009-0234-17857-A2	John A. Benedict	West Virginia Department of Environmental Protection, Division of Air Quality
EPA-HQ-OAR-2009-0234-17866-A1	Jackie L. Wilson, Mayor	City of Douglas, Georgia

EPA-HQ-OAR-2009-0234-17867-A2	Stephen Quennoz	Portland General Electric Company (PGE)
EPA-HQ-OAR-2009-0234-17868-A2	Alex Hofmann and Theresa Pugh	American Public Power Association (APPA)
EPA-HQ-OAR-2009-0234-17869-A1	Seth Jacobson	Mercury Free Partnership (MFP)
EPA-HQ-OAR-2009-0234-17870-A2	Randall R. LaBauve	NextEra Energy Inc.
EPA-HQ-OAR-2009-0234-17871-A2	Dennis P. Laybourn	Newmont Nevada Energy Investment, LLC (NNEI)
EPA-HQ-OAR-2009-0234-17872-A2	W. Lawrence Givens	Umatilla County Board of County Commissioners, Oregon
EPA-HQ-OAR-2009-0234-17873-A2	Frank P. Prager	Xcel Energy, Inc.
EPA-HQ-OAR-2009-0234-17875-A1	Susan Lyon	Center for American Progress
EPA-HQ-OAR-2009-0234-17876-A2	Deborah Fohr Levchak	Basin Electric Power Cooperative (BEPC)
EPA-HQ-OAR-2009-0234-17877-A1	Todd A. Tolbert	Associated Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17877-A2	Todd A. Tolbert	Associated Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-17878-A3	Ben Yamagata	Coal Utilization Research Council (CURC)
EPA-HQ-OAR-2009-0234-17879-A2	Thomas S. Howard	Domtar
EPA-HQ-OAR-2009-0234-17880-A2	Adrienne Esposito	Citizens Campaign for the Environment (CCE)
EPA-HQ-OAR-2009-0234-17881-A2	Louis P. Pocalujka	Consumers Energy
EPA-HQ-OAR-2009-0234-17882-A2	Shelley Vinyard	Environment America et al.
EPA-HQ-OAR-2009-0234-17883-A2	Kevin Cahill	IPR-GDF SUEZ Energy Generation NA, Inc.
EPA-HQ-OAR-2009-0234-17884-A2	Peter Glaser	Troutman Sanders LLP on be half of Peabody Energy Company
EPA-HQ-OAR-2009-0234-17885-A1	Leonard F. Hopkins	Southern Illinois Power Cooperative (SIPC)
EPA-HQ-OAR-2009-0234-17886-A2	John W. Myers	Tennessee Valley Authority (TVA)
EPA-HQ-OAR-2009-0234-17887-A2	James E. Melia	Pennsylvania Public Utility Commission (PAPUC)
EPA-HQ-OAR-2009-0234-17889-A1	Kevin Pollard	Norris Public Power
EPA-HQ-OAR-2009-0234-17890-A1	Duncan Kinchelow	Missouri Association of Municipal Utilities
EPA-HQ-OAR-2009-0234-17891-A1	William J. Yearta, Mayor	Sylvester, GA
EPA-HQ-OAR-2009-0234-17892-A1	Clay A. Gibbs	Cornhusker Public Power District

EPA-HQ-OAR-2009-0234-17895-A1	Senator Jack Reed	United States Senate
EPA-HQ-OAR-2009-0234-17897-A1	Greg Thompson, Mayor	Monroe, GA
EPA-HQ-OAR-2009-0234-17898-A1	Kathy French	Longleaf Energy Associates, LLC
EPA-HQ-OAR-2009-0234-17901-A2	Michael T.W. Carey	Ohio Coal Association (OCA)
EPA-HQ-OAR-2009-0234-17902-A2	Douglas R. Kopp	Alliant Energy Corporate Services, Inc.
EPA-HQ-OAR-2009-0234-17903-A2	Leland M. Searles	Iowa Environmental Council (IEC)
EPA-HQ-OAR-2009-0234-17904-A3	Leslie Garrett Allen	Balch & Bingham LLP on behalf of Luminant
EPA-HQ-OAR-2009-0234-17909-A1	Keith M. Stephens	PowerSouth Energy Cooperative
EPA-HQ-OAR-2009-0234-17910-A1	Robert T. Hunnicutt, Sr.	Fort Valley Utility Commission, Fort Valley, CA
EPA-HQ-OAR-2009-0234-17911-A1	Floyd Gilzow	Missouri Joint Municipal Electric Utility Commission (MJMEUC)
EPA-HQ-OAR-2009-0234-17912-A1	Les Oakes and Cynthia Stroman	King & Spalding LLP on behalf of IPP Coalition
EPA-HQ-OAR-2009-0234-17913-A1	Russ Baker	Omaha Public Power District (OPPD)
EPA-HQ-OAR-2009-0234-17914-A1	R. L. Killion	Babcock & Wilcox Power Generation Group, Inc. (B&W)
EPA-HQ-OAR-2009-0234-17915-A1	Alice Edwards	Division of Air Quality, Alaska Department of Environmental Conservation (ADEC)
EPA-HQ-OAR-2009-0234-17916-A1	John Wilkinson	Province of Ontario Ministry of the Environment, Canada
EPA-HQ-OAR-2009-0234-17917-A1	Matthew H. Mead, Governor	State of Wyoming
EPA-HQ-OAR-2009-0234-17918-A1	Dustin McDaniel	Arkansas Attorney General's Office
EPA-HQ-OAR-2009-0234-17919-A1	Scott H. Segal	Electric Reliability Coordinating Council (ERCC)
EPA-HQ-OAR-2009-0234-17920-A1	Joseph Hantz	Entergy Services, Inc.
EPA-HQ-OAR-2009-0234-17921-A1	Indra Frank	Improving Kids' Environment
EPA-HQ-OAR-2009-0234-17922-A1	Ross Gould	Environmental Advocates of New York
EPA-HQ-OAR-2009-0234-17923-A1	Craig Bressan	Prairie State Generating Company, LLC (PSGC)
EPA-HQ-OAR-2009-0234-17924-A1	James C. Welsh	Kissimmee Utility Authority (KUA)
EPA-HQ-OAR-2009-0234-17925-A2	Bill Matthews	Cleco Power LLC

EPA-HQ-OAR-2009-0234-17926-A2	Derf Johnson	Montana Environmental Information Center (MEIC)
EPA-HQ-OAR-2009-0234-17927-A2	Grant Rodway	Bison Engineering, Inc.
EPA-HQ-OAR-2009-0234-17928-A2	Paul J. Allen	Constellation Energy
EPA-HQ-OAR-2009-0234-17929-A2	James Pew	Earthjustice
EPA-HQ-OAR-2009-0234-17930-A2	Michael J. Nasi	Jackson Walker L.L.P. on behalf of Gulf Coast Lignite Coalition (GCLC)
EPA-HQ-OAR-2009-0234-17931-A2	William D. Bissett	Kentucky Coal Association (KCA)
EPA-HQ-OAR-2009-0234-17973-A1	John A. Paul	Regional Air Pollution Control Agency (RAPCA) of Dayton, Ohio
EPA-HQ-OAR-2009-0234-17974-A1	James O. Vick	Florida Electric Power Coordinating Group, Inc. (FCG)
EPA-HQ-OAR-2009-0234-17975-A1	Eric Schaeffer	Environmental Integrity Project (EIP)
EPA-HQ-OAR-2009-0234-18014-A2	Larry J. Koshire	Rochester Public Utlities (RPU)
EPA-HQ-OAR-2009-0234-18015-A2	Edward Z. Fox	Arizona Public Service Company (APS)
EPA-HQ-OAR-2009-0234-18016-A2	John D. Free	Alabama Public Service Commission (APSC)
EPA-HQ-OAR-2009-0234-18017-A2	David V. Modeer	Central Arizona Water Conservation District (CAWCD)
EPA-HQ-OAR-2009-0234-18018-A2	Barry Moline	Florida Municipal Electric Association (FMEA)
EPA-HQ-OAR-2009-0234-18019-A2	Susan Ackerman and John Savage	Oregon Public Utility Commission (OPUC)
EPA-HQ-OAR-2009-0234-18020-A2	Jonathan Oliver	Arkansas Electric Cooperative Corporation (AECC)
EPA-HQ-OAR-2009-0234-18021-A2	James M. Landreth	South Carolina Electric and Gas Company (SCE&G)
EPA-HQ-OAR-2009-0234-18022-A2	Ross Gould	Environmental Advocates of New York
EPA-HQ-OAR-2009-0234-18023	Chris Hobson	Southern Company
EPA-HQ-OAR-2009-0234-18023-A2	Chris M. Hobson	Southern Company
EPA-HQ-OAR-2009-0234-18024-A2	John P. Reese	US Power Generating Company (USPG)
EPA-HQ-OAR-2009-0234-18025-A2	Eric B. Svenson	PSEG Services Corporation
EPA-HQ-OAR-2009-0234-18026-A2	Kevin Schmidt	Ohio Manufacturers' Association (OMA)
EPA-HQ-OAR-2009-0234-18027-A2	Vickie Patton	Environmental Defense Fund (EDF)
EPA-HQ-OAR-2009-0234-18028	J. Butera	Environmental Defense Fund (EDF)

EPA-HQ-OAR-2009-0234-18029-A2	Thomas M. Gibbons	Jersey City Environmental Commission
EPA-HQ-OAR-2009-0234-18030-A2	Bill Schuette	State of Michigan Attorney General Office
EPA-HQ-OAR-2009-0234-18031-A2	Michael G. Cashin	Minnesota Power (ALLETE)
EPA-HQ-OAR-2009-0234-18032-A2	Jim Weeks	Michigan Municipal Electric Association (MMEA)
EPA-HQ-OAR-2009-0234-18033-A2	Thomas C. Perry	National Mining Association (NMA)
EPA-HQ-OAR-2009-0234-18034-A2	Mark R. Vickery	Texas Commission on Environmental Quality (TCEQ)
EPA-HQ-OAR-2009-0234-18034-A3	Mark R. Vickery	Texas Commission on Environmental Quality (TCEQ)
EPA-HQ-OAR-2009-0234-18035-A2	Lauren Freeman, et al. Hunton & Williams LLP	Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2009-0234-18036-A2	Aaron Flynn, Hunton & Williams LLP	Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2009-0234-18037-A2	Douglas L. Biden	Electric Power Generation Association (EPGA)
EPA-HQ-OAR-2009-0234-18038-A2	Justin M. Nickels	City of Manitowoc Public Utilities, Wisconsin
EPA-HQ-OAR-2009-0234-18039-A2	Kenneth L. Kimmell	Massachusetts Department of Environmental Protection (MassDEP)
EPA-HQ-OAR-2009-0234-18043-A2	Allison D. Beals	Adirondack Mountain Club (ADK)
EPA-HQ-OAR-2009-0234-18051-A2	Greg Schaefer	Arch Coal, Inc. (ACI)
EPA-HQ-OAR-2009-0234-18248-A2	Joseph Mendelson III	National Wildlife Federation (NWF)
EPA-HQ-OAR-2009-0234-18414-A1	Larry L. Guest, Mayor	City of Elberton, Georgia
EPA-HQ-OAR-2009-0234-18415-A1	W. Kurt Foreman	North Louisiana Economic Partnership (NLEP)
EPA-HQ-OAR-2009-0234-18416-A1	Greg Hines, Mayor	City of Rogers, Arkansas
EPA-HQ-OAR-2009-0234-18417-A1	Patsy Meck	Panola County Economic Development Corporation
EPA-HQ-OAR-2009-0234-18418-A1	Doug Sprouse, Mayor	City of Springdale, Arkansas
EPA-HQ-OAR-2009-0234-18419-A1	Jennifer G. Trammell	Greater Shelby County Chamber of Commerce
EPA-HQ-OAR-2009-0234-18420-A1	Perry Webb	Springdale Chamber of Commerce
EPA-HQ-OAR-2009-0234-18421-A2	Susanne Brooks	Environmental Defense Fund

		(EDF)
EPA-HQ-OAR-2009-0234-18422-A1	Ted Hampton	Utah Associated Municipal Power Systems (UAMPS)
EPA-HQ-OAR-2009-0234-18422-A2	Ted Hampton	Utah Associated Municipal Power Systems (UAMPS)
EPA-HQ-OAR-2009-0234-18423-A2	David Bookbinder	Julander Energy Company
EPA-HQ-OAR-2009-0234-18424-A2	J. Nathan Noland	Indiana Coal Council, Inc.
EPA-HQ-OAR-2009-0234-18425-A2	Erika Padgett	Clean Wisconsin, et al.
EPA-HQ-OAR-2009-0234-18426-A2	G. Vinson Hellwig	Michigan Department of Environmental Quality (MDEQ)
EPA-HQ-OAR-2009-0234-18427-A2	Kerry Kelly	Waste Management (WM)
EPA-HQ-OAR-2009-0234-18428-A2	Caroline Choi	Progress Energy
EPA-HQ-OAR-2009-0234-18429-A2	Coment submitted by Brian L. Warner	Wolverine Power Supply Cooperative, Inc. (WPSCI)
EPA-HQ-OAR-2009-0234-18430-A2	Robert F. McDonnell	Commonwealth of Virginia
EPA-HQ-OAR-2009-0234-18431-A1	John Blair	Valley Watch, Inc.
EPA-HQ-OAR-2009-0234-18432-A2	Adam H. Cutler	Public Interest Law Center of Philadelphia
EPA-HQ-OAR-2009-0234-18433-A2	Joaquin C. Flores, P.E.	Guam Power Authority (GPA)
EPA-HQ-OAR-2009-0234-18433-A3	Joaquin C. Flores, P.E.	Guam Power Authority (GPA)
EPA-HQ-OAR-2009-0234-18433-A4	Joaquin C. Flores, P.E.	Guam Power Authority (GPA)
EPA-HQ-OAR-2009-0234-18434-A2	David Gardiner	The Alliance for Industrial Efficiency
EPA-HQ-OAR-2009-0234-18435-A2	American Academy of Pediatrics et al.	American Lung Association et al.
EPA-HQ-OAR-2009-0234-18436-A2	Jenny Dorgan	Alabama Rivers Alliance
EPA-HQ-OAR-2009-0234-18437-A1	Patrick L. Pope	Nebraska Public Power District
EPA-HQ-OAR-2009-0234-18438-A2	Vickie Patton	Environmental Defense Fund (EDF)
EPA-HQ-OAR-2009-0234-18439-A2	Lisa Jacobson	Business Council for Sustainable Energy (BCSE)
EPA-HQ-OAR-2009-0234-18440-A2	Dustin McCaniel	Arkansas Attorney General's Office
EPA-HQ-OAR-2009-0234-18441-A2	Craig Glazer	PJM Interconnection, L.L.C.
EPA-HQ-OAR-2009-0234-18442-A1	Michael G. Dowd	Virginia Department of Environmental Quality (VADEQ)
EPA-HQ-OAR-2009-0234-18443-A1	Michalene Reilly	Hoosier Energy Rural Electric

		Cooperative, Inc.
EPA-HQ-OAR-2009-0234-18444-A2	William O'Sullivan, P.E.	State of New Jersey Department of Environmental Protection
EPA-HQ-OAR-2009-0234-18445-A2	Edward F. Miller	American Lung Association (ALA)
EPA-HQ-OAR-2009-0234-18446-A2	Thomas Horne	State of Arizona et al.
EPA-HQ-OAR-2009-0234-18447-A2	Brian Trower	Ames Municipal Electric System
EPA-HQ-OAR-2009-0234-18448-A2	Craig A. Glazer	PJM Interconnection, L.L.C. et al.
EPA-HQ-OAR-2009-0234-18449-A2	Frank Schaedlich	Tekran Instruments Corporation
EPA-HQ-OAR-2009-0234-18450-A2	Donald Neal	Calpine Corporation
EPA-HQ-OAR-2009-0234-18477-A3	Ronald R. Cox	Hawaiian Electric Company, Inc.
EPA-HQ-OAR-2009-0234-18478-A1	Lois Capps, et al.	Congress of the United States
EPA-HQ-OAR-2009-0234-18480-A1	Neal F. Niedfeldt	City of Beatrice, Nebraska
EPA-HQ-OAR-2009-0234-18481-A1	William I. McLarty, Mayor	City of South Sioux City, Nebraska
EPA-HQ-OAR-2009-0234-18482-A1	Ann H. Campbell, Mayor	Mayor's Office, City of Ames, Iowa
EPA-HQ-OAR-2009-0234-18483-A2	Larry G. Carlson	Tenaska, Inc.
EPA-HQ-OAR-2009-0234-18484-A2	Steven C. Borell	Alaska Miners Association (AMA)
EPA-HQ-OAR-2009-0234-18486-A2	Mark Maslyn	American Farm Bureau Federation
EPA-HQ-OAR-2009-0234-18487-A2	Sierra Club, et al.	Sierra Club, et al.
EPA-HQ-OAR-2009-0234-18488-A2	Edward L. Kropp	Midwest Ozone Group (MOG)
EPA-HQ-OAR-2009-0234-18489-A2	Marion Loomis	Wyoming Mining Association (WMA)
EPA-HQ-OAR-2009-0234-18497-A2	Jolene M. Thompson	American Municipal Power, Inc. (AMP)
EPA-HQ-OAR-2009-0234-18498-A2	Jerry Purvis	East Kentucky Power Cooperative, Inc. (EKPC)
EPA-HQ-OAR-2009-0234-18499-A2	Sal LoBianco	Muscatine Power and Water
EPA-HQ-OAR-2009-0234-18500-A2	Climate Policy Group (CPG)	Climate Policy Group (CPG)
EPA-HQ-OAR-2009-0234-18501-A2	Tyler Edgar	National Council of Churches
EPA-HQ-OAR-2009-0234-18502-A2	Late Miguel A. Cordero Lopez	Puerto Rico Electric Power Authority (PREPA)
EPA-HQ-OAR-2009-0234-18538-A2	Donna L. Nelson	Public Utility Commission of Texas (Texas PUC)
EPA-HQ-OAR-2009-0234-18539-A1	Al DePaoli	AES Corporation
EPA-HQ-OAR-2009-0234-18540-A2	Louis J. Manuel Jr.	Ak-Chin Indian Community
EPA-HQ-OAR-2009-0234-18541-A1	J. Fitzgerald and	None

	C. R. de Azua	
EPA-HQ-OAR-2009-0234-18575-A1	Heartland Consumers Power District	Heartland Consumers Power District
EPA-HQ-OAR-2009-0234-18576-A2	Sherri Bulkley, et al.	American Lung Association in Hawaii
EPA-HQ-OAR-2009-0234-18590-A2	Robin Grant	American Lung Association in Tennessee (ALATN)
EPA-HQ-OAR-2009-0234-18644-A2	S. Nelson Jr.	None
EPA-HQ-OAR-2009-0234-18666-A1	P. Difani	None
EPA-HQ-OAR-2009-0234-18705-A1	Michael P. Marcotte	City of Alexandria, Louisiana
EPA-HQ-OAR-2009-0234-18706-A1	Bucky Johnson, Mayor	City of Norcross, Georgia
EPA-HQ-OAR-2009-0234-18707-A2	Linda McGrath	American Lung Association in Idaho
EPA-HQ-OAR-2009-0234-18716-A2	Taylor A. Davis III, Patty Unfred and Matthew Walker	American Lung Association in Oregon
EPA-HQ-OAR-2009-0234-18721-A2	Jon Breiner, et al.	American Lung Association in Washington
EPA-HQ-OAR-2009-0234-18749-A2	Mike Moody	American Lung Association in Kentucky
EPA-HQ-OAR-2009-0234-18750-A2	Harry Perlstadt	American Lung Association in Michigan
EPA-HQ-OAR-2009-0234-18751-A2	William Lawson and Jesse Neeley	American Lung Association in Tennessee
EPA-HQ-OAR-2009-0234-18759-A2	Rick MacCornack	Washington Asthma Initiative (WAI)
EPA-HQ-OAR-2009-0234-18785-A2	Eddy Young	Optim Energy LP, Twin Oaks
EPA-HQ-OAR-2009-0234-18820-A1	M. Stiefermann	Central Electric Power Cooperative
EPA-HQ-OAR-2009-0234-18823-A2	John Cloud	American Lung Association in Ohio
EPA-HQ-OAR-2009-0234-18831-A1	Berdell Knowles	JEA
EPA-HQ-OAR-2009-0234-18894-A1	Ric Hall, Mayor	City of Blakely, Georgia
EPA-HQ-OAR-2009-0234-18897-A2	Daniel Sutton	American Lung Association in Ohio (ALAO)
EPA-HQ-OAR-2009-0234-18898-A2	Linn Billingsley	American Lung Association, Nevada
EPA-HQ-OAR-2009-0234-18899-A2	Marlis Hadley	American Lung Association, New Mexico
EPA-HQ-OAR-2009-0234-18900-A2	Caroline Moassessi	American Lung Association, Nevada

EPA-HQ-OAR-2009-0234-18901-A2	Andy Boyce	American Lung Association, Nevada
EPA-HQ-OAR-2009-0234-18907-A2	Charles D. Bennett	Marathon Petroleum Company LP
EPA-HQ-OAR-2009-0234-18924-A1	Jim Hawks	City of North Platte
EPA-HQ-OAR-2009-0234-18930-A2	Connie Shawler et al.	American Lung Association in Arizona
EPA-HQ-OAR-2009-0234-18933-A2	Michael S. Hubbard	National Council of Textile Organizations (NCTO)
EPA-HQ-OAR-2009-0234-18934-A2	Nicky Sheats, Esq.	New Jersey Environmental Justice Alliance (NJEJA)
EPA-HQ-OAR-2009-0234-18935-A2	Jon Howard	Weston Solutions, Inc.
EPA-HQ-OAR-2009-0234-18936-A1	Hays Arnold, Mayor	City of Thomaston, GA
EPA-HQ-OAR-2009-0234-18937-A1	Kimberly C. Carter, Mayor	City of Covington, GA
EPA-HQ-OAR-2009-0234-18944-A1	Charles Sherwood	City of Ellaville, GA
EPA-HQ-OAR-2009-0234-18961-A2	Meg Voorhes	US SIF – The Forum for Sustainable and Responsible Investment
EPA-HQ-OAR-2009-0234-18963-A2	Daniel Traynor	Northampton Generating Company, L.P
EPA-HQ-OAR-2009-0234-18964-A2	CONSOL Energy Inc.	CONSOL Energy Inc.
EPA-HQ-OAR-2009-0234-19032-A1	James M. Andrew	Arizona Electric Power Cooperative, Inc. (AEPCO)
EPA-HQ-OAR-2009-0234-19033-A1	Samuel H. Bruntz	Alcoa Power Generating, Inc. (APGI)
EPA-HQ-OAR-2009-0234-19040-A1	D. S. McKeown	None
EPA-HQ-OAR-2009-0234-19041-A1	Steven K. Nelson	The Frontier Power Company
EPA-HQ-OAR-2009-0234-19042-A2	James Parkhurst	EOP Foundation
EPA-HQ-OAR-2009-0234-19094-A1	Michael C. Stiefermann	Central Electric Power Cooperative (CEPC)
EPA-HQ-OAR-2009-0234-19101-A1	James J. Egge	Audubon Chapter of Minneapolis
EPA-HQ-OAR-2009-0234-19111-A1	Linda Vanderveen	Conservation Chair, Hernando Audubon of Florida
EPA-HQ-OAR-2009-0234-19114-A1	John M. McManus	American Electric Power (AEP)
EPA-HQ-OAR-2009-0234-19120-A1	Angelique Oliger	Indianapolis Power & Light Company (IPL)
EPA-HQ-OAR-2009-0234-19121-A1	Jon A. Finlinson	Intermountain Power Service Corporation (IPSC)
EPA-HQ-OAR-2009-0234-19122-A1	Mark J. Sedlacek	Los Angeles Department of Water

		and Power (LADWP)
EPA-HQ-OAR-2009-0234-19123-A1	Markus I. Bryant	Lorain-Medina Rural Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-19143-A1	John (no surname provided)	None
EPA-HQ-OAR-2009-0234-19145-A1	Juan M. Cofield	National Association for the Advancement of Colored People (NAACP)
EPA-HQ-OAR-2009-0234-19199-A1	Heath R. VanNatter	House of Representative, State of Indiana
EPA-HQ-OAR-2009-0234-19205-A1	L. Garvey	None
EPA-HQ-OAR-2009-0234-19209-A1	Markus I. Bryant	North Central Electric Cooperative, Inc.
EPA-HQ-OAR-2009-0234-19210-A1	Richard H. Baker	Pelican Island Audubon Society
EPA-HQ-OAR-2009-0234-19211-A1	Joseph Croce	Virginia Manufacturers Association (VMA)
EPA-HQ-OAR-2009-0234-19212-A2	James D. Atterholt	Indiana Utility Regulatory Commission (IURC) et al.
EPA-HQ-OAR-2009-0234-19213-A1	J. Michael Houston, Mayor	City of Springfield, Illinois
EPA-HQ-OAR-2009-0234-19214-A1	Willie R. Taylor, Director	United States Department of the Interior
EPA-HQ-OAR-2009-0234-19225-A1	Mike Godwin	Orange Audubon Society
EPA-HQ-OAR-2009-0234-19296-A1	Richard H. Bremer	Greater Shreveport Chamber of Commerce
EPA-HQ-OAR-2009-0234-19506-A1	Thomas W. Easterly	Indiana Department of Environmental Management
EPA-HQ-OAR-2009-0234-19540	Ann Brewster Weeks	Clean Air Task Force, et al.
EPA-HQ-OAR-2009-0234-19549-A1	David Theiss, Mayor	City of Ellaville, Georgia
EPA-HQ-OAR-2009-0234-19559-A1	C. Neil Mayer	City of Whigam, Georgia
EPA-HQ-OAR-2009-0234-19560-A1	Lemuel O. Edwards	Albany Water Gas & Light Commission, Albany, Georgia
EPA-HQ-OAR-2009-0234-19564-A1	Jamey D. Pankoke	Perennial Public Power District
EPA-HQ-OAR-2009-0234-19565-A1	Brian Lukasiewicz	Howard Greeley Rural Public Power District
EPA-HQ-OAR-2009-0234-19566-A1	L. J. Joey Durel, Jr.	Lafayette Utilities System, Louisianna
EPA-HQ-OAR-2009-0234-19574-A1	Thomas E. Rudloff	Elkhorn Rural Public Power District
EPA-HQ-OAR-2009-0234-19580-A1	Jay Timmons	National Association of

		Manufacturers (NAM)
EPA-HQ-OAR-2009-0234-19581-A1	Kent Greenwalt, Mayor	City of Terrytown
EPA-HQ-OAR-2009-0234-19595	N.A. Bishop	City of Terrytown
EPA-HQ-OAR-2009-0234-19601-A1	J. M. Gibney, Jr.	Wahoo Public Utility
EPA-HQ-OAR-2009-0234-19603-A1	Steve Rentfrow	Crisp County Power Commission
EPA-HQ-OAR-2009-0234-19622-A2	Adriana Oller	Nickel Producers Environmental Reseach Association (NiPERA, Inc)
EPA-HQ-OAR-2009-0234-19653-A1	Richard Marshall	Spectrum Systems Inc.
EPA-HQ-OAR-2009-0234-19654	Rick Wajda	Indiana Builders Association (IBA)
EPA-HQ-OAR-2009-0234-19671-A2	Lee A. Casey, Counsel, Baker & Hostetler LLP on behalf of Institute for Liberty et al.	Institute for Liberty et al.
EPA-HQ-OAR-2009-0234-19671-A3	Lee A. Casey, Counsel, Baker & Hostetler LLP on behalf of Institute for Liberty et al.	Institute for Liberty et al.
EPA-HQ-OAR-2009-0234-19677-A1	Michael Ralston	Iowa Association of Business and Industry (ABI)
EPA-HQ-OAR-2009-0234-19678-A2	Barbara A. Walz	Tri-State Generation and Transmission Association, Inc.
EPA-HQ-OAR-2009-0234-19679	John Artes	Maryland Department of the Environment
EPA-HQ-OAR-2009-0234-19741	A. Gwen Ecklund	West Associates
EPA-HQ-OAR-2009-0234-19742	Andrew J. Such	Michigan Manufacturer's Association